Kazakhstan Association of Oil, Gas and Energy Sector Organizations, KAZENERGY

THE NATIONAL ENERGY REPORT KAZENERGY 2023

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Ladies and Gentlemen, Dear Readers!

Since the publication of the KAZENERGY National Energy Report 2021, the global economy has witnessed major shifts – the global energy industry is facing many challenges and transformations. We are experiencing a growing demand for energy with volatile energy prices, a realignment of global supply chains, an increasing awareness of environmental responsibility, and the need to combat climate change. The issue of depreciation and inevitable aging of the industry's infrastructure becomes particularly acute, which pushes us towards the development of new energy security and risk management strategies.

At the same time, along with the emergence of global challenges, we also gain unprecedented opportunities. The rapid development of technologies, including renewable energy sources, innovations in energy efficiency, modern energy storage methods and digitalization open up new horizons for our industry. We can use these opportunities to create a more sustainable, reliable, efficient and flexible energy system.

In current conditions, the KAZENERGY National Energy Report 2023 is an important mechanism for assessing the current state of the energy sector in Kazakhstan, as well as determining strategic prospects and priorities for the coming years. The report represents the result of collaboration between the KAZENERGY Association's professionals, Kazakhstani and international experts, representatives of business, the scientific community and government agencies that cooperate closely with the KAZENERGY Association.

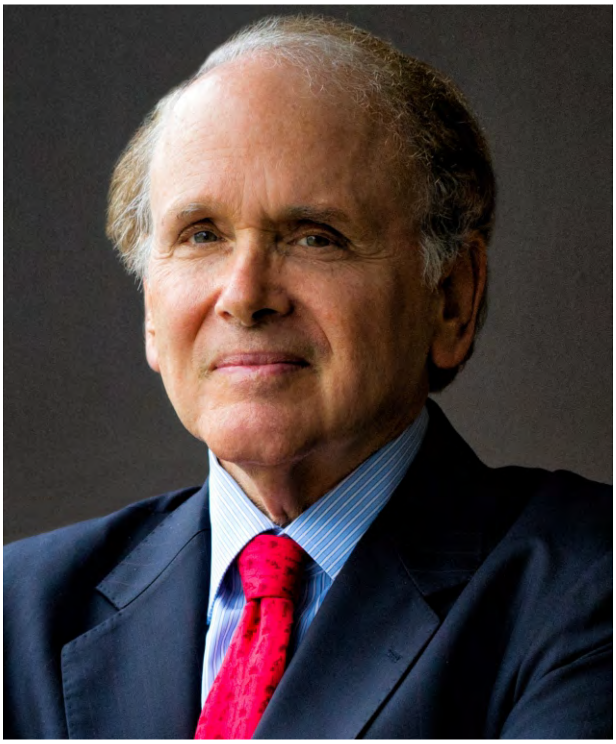
An important aspect of the Report 2023 was the KAZENERGY team's work on the conceptual vision for the development of the Energy Security Strategy of the Republic of Kazakhstan and a serious study of the experience of the world's advanced economies.

Today, the application of a systems approach to planning the development of an efficient energy complex in the republic, which allows for a reduction of these risks and increases the competitiveness of the economy, is of particular relevance for Kazakhstan. The Government of the country and the national energy community consistently implement systemic changes to regulate the industry and solve ambitious tasks in the field of decarbonization of the national economy outlined by the President of the Republic of Kazakhstan Kassym-Jomart Tokayev.

I would like to express my sincere gratitude to all participants of the KAZENERGY National Energy Report publishing project. Your contribution, expertise and suggestions are key elements of its value and credibility.

I hope that the KAZENERGY National Energy Report 2023 will form the basis for further dialogue and cooperation between government agencies, business and the scientific community, and will become an independent guide for the development of a balanced state policy and making important decisions that promote sustainable development of the energy sector of Kazakhstan.

Sincerely,
Timur Kulibayev
Chairman KAZENERGY Association



Dear Readers!

Yet again we have the distinct honor of participating in the preparation of The KAZENERGY National Energy Report 2023 for Kazakhstan (NER 2023). This marks our fifth edition of this significant Report covering the importance, diversity, successes, and challenges of Kazakhstan's energy sector. This year also marks two important 30-year anniversaries in Kazakhstan: both the Tengizchevroil joint venture (TCO) developing the Tengiz field and the KazakhstanCaspiyShelf Consortium (KCS) that became the NCOC (North Caspian Operating Company) developing the Kashagan field were established in 1993.

This Report comes at another critical juncture for Kazakhstan and the world as a whole. Global disruptions in energy markets from the ongoing military conflict in Ukraine have raised the importance of energy security in overall policy-making. The push for renewable energy and the drive toward net-zero carbon emissions remain important goals, of course, as the global consensus around climate change and the energy transition becomes stronger. But the enormous challenges to that transition are also becoming clearer. In addition to the uncertain pace of the development and deployment of clean-energy technologies, four issues in particular stand out: (1) the reemphasis on energy security as a prime requirement for countries; (2) lack of consensus on how fast the energy transition should and can take place in different places across the globe, in part because of its potential economic disruptions; (3) a sharpening divide between advanced and developing countries on priorities in the transition; and (4) obstacles to expanding mining and building supply chains for the minerals needed for the net-zero objective.

The first issue, energy security, is a key theme of NER 2023, as it has particular salience for Kazakhstan. Globally, the concern over energy security had faded somewhat over the previous few years. But the 2022 energy shock, the economic hardships that ensued in different quarters, skyrocketing energy prices that could not have been imagined two years ago, and geopolitical conflicts—all have combined to force many governments and companies to reassess their energy transition strategies. This reassessment recognizes that the energy transition needs to be grounded in energy security—that is, adequate and reasonably priced energy supplies—to ensure public support and avoid severe economic dislocations. It is useful to view the role of coal in Kazakhstan's economy through this particular prism—despite its outsize contributions to Kazakhstan's carbon footprint, this low-cost, domestically available fuel provides essential ballast for the greater risks involved in the other elements of the overall energy transition.

For Kazakhstan, the energy sector is the very foundation for its overall economic security and well-being. Although Kazakhstan's economy has experienced considerable development and some diversification in the three decades since independence, hydrocarbons and other energy resources still remain central in the national economy. The oil and gas industries alone, together with related sectors (e.g., oil and gas transportation, upstream construction, and geology), contributed around 20% of the country's GDP in 2022, with oil accounting for 60% of Kazakh export earnings and constituting the primary source of the government's budgetary revenue. The development of the oil and gas industry has been a source of strength, generating economic activity, employment, and revenues that have been crucial since 1991 in solidifying Kazakhstan's independence as a nation and improving the incomes and standards of living for its people. It has also fortified Kazakhstan's relations with its neighbors and established the country as a reliable partner and major force in the global oil industry and a significant participant in global markets, the world community, and global affairs.

But this also increases the national economy's vulnerability to external shocks. More specifically, the economy's heavy reliance on hydrocarbon revenue increases its sensitivity to swings in global oil prices, as repeatedly demonstrated in recent years. Notably, both the contraction of Kazakh GDP in 2020 and subsequent strong rebound (in 2021) largely paralleled world oil price trends, while the slowing of national GDP growth in 2022-23 reflected the deceleration of oil price growth in 2022 and price decline in 2023. Notwithstanding these vulnerabilities, the energy sector generally, and the hydrocarbon industry in particular, is expected to remain a key driver of Kazakh economic growth throughout the outlook period to 2050.

Given the importance of the energy sector within Kazakhstan's economy, revenues from exports of hydrocarbons and other energy resources will be essential for economic diversification initiatives and for funding the country's ongoing transition to low-carbon energy in the future. But Kazakhstan will face increased competition for scarce foreign investment capital worldwide (including from other major hydrocarbon-producing countries). Investor-companies will still compete for new opportunities, but they are exercising much greater capital discipline, increasing the competition among resource-holding countries for available investment in new projects. It will be important in this new environment for Kazakhstan's policymakers to take steps, through enlightened fiscal and other policies, to demonstrate they are holders of "advantaged" supplies that can be developed, produced, and delivered at relatively low cost and with a low carbon footprint and, at the same time, with reasonable regulatory certainty and timely decision-making. These are the key criteria on which international companies will make their investment decisions.

Yet resilience in response to macroeconomic shocks and creation of an attractive investment environment are but two dimensions of Kazakhstan's energy security warranting attention in NER 2023. This includes the importance of diversification of Kazakhstan's oil export routes, as the West's response to Russia's invasion of Ukraine has dramatically reoriented the geography of global oil and gas trade and greatly increased transit risk. Other elements of Kazakhstan's energy security include raising the overall resilience of the country's electrical grid (increasingly important in accommodating both greater electrification and a larger share of intermittent renewable generation entering the grid as part of decarbonization efforts) and more energy storage. Finally, the importance of policy resilience—broad public agreement regarding the direction of decarbonization and overall energy policy—cannot be ignored. We believe that a key approach needed to enhance overall policy resilience is to ground the energy sector within a broader market-economy framework, with market supply and demand fundamentals driving prices and allocating resources. This includes adoption of a general open-trade stance internationally with respect to energy.

If energy security is the first challenge of the transition, timing is the second. The energy transition will be an extremely challenging, multidecadal process that will require extraordinary changes in energy use, technology, and policy. How fast should it—and can it—proceed? There is much pressure to accelerate a significant part of the 2050 carbon reduction emission targets toward 2030. But it sometimes seems that the scale of what is being attempted is underestimated. In investigating Kazakhstan's energy transition and greenhouse gas reduction initiatives, and comparing them with decarbonization programs undertaken internationally, we offer recommendations for the reform of one of the more important elements of Kazakhstan's Low-Carbon Development Strategy to 2060—the Emissions Trading System. We observe the paradox for Kazakhstan is that while the reduction of coal consumption in the electric power sector is the single most effective step it can take toward reducing its greenhouse gas emissions, coal—when used judiciously—can also be an important near-term stabilizer (energy "security blanket") in what will likely be a bumpy transition path.

Another source of stability is international collaboration, as evidenced in Kazakhstan's participation since 2020 in the organized crude oil production cuts by the OPEC+ group of major world producers. OPEC+ has helped to stabilize global energy markets, driving world oil prices up from very low levels (and with that, export revenues for oil exporters) by managing global supply to more closely correspond with demand. Another area of broad regional cooperation that could enhance security in the energy space is the pending formation of single markets within the Eurasian Economic Union (EAEU) for oil and oil products, natural gas, and electric power. Accession to the EAEU single markets provides a mechanism whereby Kazakh energy prices can gradually rise to parity with those in fellow EAEU member-states (particularly Russia) as part of a general movement toward integrated open markets. Higher energy prices will provide clear benefits by increasing the efficiency of energy consumption (in the process lowering GHG emissions) and reducing unauthorized ("grey") exports to consumers in bordering countries.

Energy security concerns have now also modified, although not totally transformed, the transition strategies of major international energy companies. On the eve of the conflict in Ukraine, many hydrocarbon producers expected to reach maximum oil and gas output earlier and at lower levels than forecasted prior to the COVID-19 pandemic, and pursued portfolio diversification, mergers and acquisitions (M&A), divestments, and new clean-energy ventures to reflect this expectation. But energy security concerns stemming from rising prices and disrupted supply chains following the outbreak of the conflict in Ukraine have caused many industry executives to reassess their business plans and approaches to the transition in general. In the current strong demand environment, some "first mover" companies in the energy transition have pushed back the timetable for reducing oil and gas production. The international oil majors are concentrating their activities closer to home geographically, in better known geological and political environments, while exercising increased capital discipline. National oil companies, although a diverse group, generally have continued to focus on monetizing their hydrocarbon resources as effectively as possible in an increasingly competitive investment environment.

Nonetheless, this change in approach is more a mid-course correction than a major reorientation of transition strategy. Companies continue to emphasize increasing cost-efficiency in their operations and embracing powerful technological innovations (big data, cloud computing, artificial intelligence) to cut costs and boost production from existing assets. Many also continue to execute plans to become more diversified energy companies by building out renewable energy capacity, electric vehicle charging stations, and carbon capture, use, and storage (CCUS) installations.

And there is a growing recognition that substantial progress toward reducing greenhouse gas (GHG) emissions will require the use of both proven low-carbon technologies such as wind and solar power in electric power generation, as well as technologies currently only at the experimental phases, such as hydrogen in sectors that are more difficult to decarbonize (heavy industry and transportation). This does not mean that hydrocarbon energy resources will no longer be important. They will continue to play a major role in the world economy throughout the outlook period (to 2050). However, the focus will increasingly shift to reducing their climate impact and increasing the efficiency of their consumption.

We present NER 2023 at this key juncture in the development of Kazakhstan's energy sector with the same sense of optimism and purpose as our first Report issued back in 2015. Our shared goal is to contribute to and advance an ongoing process of understanding, and with it decision-making and policy formation, that will enable Kazakhstan to meet its energy, security, and environmental challenges while promoting the economic and social welfare of its population.

Dr. Daniel Yergin

Vice Chairman S&P Global

October 2023

Appreciation

The KAZENERGY National Energy Report 2023 was prepared by the KAZENERGY Association (with active participation from its members) and by S&P Global together with Avantgarde Advisory. However, it builds on a foundation established by many years of previous research and analysis undertaken by many different experts, both within Kazakhstan and abroad. These specialists come from a diverse array of organizations, including KAZENERGY Association members, state authorities of the Republic of Kazakhstan, many research, development, design and engineering entities, as well as companies operating in the sector. The contributions of all these experts are essential and gratefully acknowledged. This most recent Report is published in 2023 as the world deals with the after-effects of an energy shock brought on by global geopolitical tensions and changes in the world order. This year also marks the 30th anniversary of the establishment in Kazakhstan of two multi-national consortia developing the Tengiz and Kashagan oil and gas mega-projects. It is a reminder of Kazakhstan's emergence, in just a few short decades, as a major player in global energy markets and a stable partner in the energy space internationally.

Preparation of NER 2023 during a period of international geopolitical turbulence and disrupted trade flows and travel arrangements presented some research challenges, including in obtaining data and making outlooks. We are grateful to the entities that took the time to conduct both virtual and on-site interviews with the research team. We are also grateful to the KAZENERGY member companies and governmental agencies that responded to information requests and provided indispensable written feedback, data inputs, and insights.

We especially thank the Avantgarde Advisory represented by its General Director, Ruslan Mukhamedov, as well as Oleg Arkhipkin, who were actively involved in preparation of this Report and provided the content of the electric power, coal, and uranium chapters, as well as Ekaterina de Vere Walker of SEEPX, who developed the electric power chapter, along with contributions from Andrey Kibarin, Tatyana Polyanichkina, and Alisher Kurbanaliev.

Numerous specialists within and outside Kazakhstan also reviewed individual chapters of the Report corresponding to their individual areas of expertise. We genuinely appreciate their suggestions and comments.

We especially thank Timur Kulibayev, Chairman of the KAZENERGY Association; Uzakbay Karabalin, Deputy Chairman of the KAZENERGY Association; Kenzhebek Ibrashev, General Director of the KAZENERGY Association; and Rustam Zhursunov, Ombudsman for the Protection of the Rights of Entrepreneurs of Kazakhstan. This Report would not have been possible without their active assistance, expert advice, and support.

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In closing, throughout the preparation of this Report we have once again been truly fortunate to have worked with many extraordinary and talented colleagues in Kazakhstan. It is a special honor to present this report during the convocation of the Kazakhstan Energy Week – 2023 and XV KAZENERGY Eurasian Forum, hosted in Astana and devoted to important issues of Kazakhstan's energy future.

In Appreciation,

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CHAPTER 1

GLOBAL ECONOMIC AND ENERGY MARKET DYNAMICS, 2022–23 AND FUTURE OUTLOOK

1. GLOBAL ECONOMIC AND ENERGY MARKET DYNAMICS, 2022–23 AND FUTURE OUTLOOK

1.1 Key Points

► As a result of the economic effects of the global COVID-19 pandemic, total global primary energy demand fell by 3.9% in 2020, but then rebounded in 2021 and 2022 to surpass the pre-pandemic level; more specifically, global primary energy demand grew by 4.9% in 2021, followed by 1.4% growth in 2022 (to 15.0 billion tons of oil equivalent). Oil (i.e., crude and condensate) continued to be the most widely consumed form of primary energy in 2022, accounting for 30.5% of global primary energy demand, followed by coal (26.8%) and then natural gas (22.9%).

► Among the different forms of primary energy, renewable energy increased the most in relative terms (14.0%) in the 2022 primary energy demand mix, followed by oil (2.9%). Surprisingly, coal continued a slow (albeit temporary) upward trajectory, increasing by 1.4%. Gas demand, meanwhile decreased slightly (-0.8%). The reversal in the fortunes of the two fuels – gas and coal – rather than reflecting long-term trends, instead was due to a combination of more immediate developments: a dramatic fall in European gas demand as Russia reduced supplies to the Continent as a result of the conflict in Ukraine, weaker than expected Chinese demand owing to the country's protracted post-COVID economic recovery, and a temporary reversal of net coal-to-gas switching in power generation and industry as gas prices spiked and drought lowered hydroelectric power generation in some regions (e.g., Europe, Eurasia); this left coal to fill the gap.

► The S&P Global Commodity Insights (base case or expected) outlook for global primary energy demand to 2050 features a steady shift in the 2030s and 2040s toward lower carbon energy sources across most major economies. By the mid-2030s, fossil fuel consumption trends on a consistently downward path, while market penetration by renewables increases steadily. Total primary energy demand increases by 15% (0.5% annually) over the present level by 2050, despite a doubling of global GDP and an increase of global population by some 2 billion; this is the result of a concurrent reduction in energy intensity (2.0% annually) associated with improvements in energy efficiency.

► Global liquids[1] demand peaks in the early 2030s, and gradually falls back to 2022 levels by the late 2040s. Although oil loses market share and total demand falls, it remains the largest contributor to total primary energy demand (TPED) even in 2050 (at 4,334.7 MMtoe, 25% of TPED). Natural gas will play an important bridge role to a low-carbon future. The share of gas in TPED in 2050 (22%) is virtually the same as at present (23%), although the volume consumed is projected to be about 12% higher. Similarly, nuclear and hydroelectric power will remain vital sources of zero-emission power generation in the new energy system, although their shares in TPED will not change appreciably from present levels. The most rapid increase in TPED over the 2022–50 period is non-hydro renewables, which increase at an average rate of 7.4% annually, reaching 20% of TPED (nearly seven times the current share). In contrast, coal demand (starting from 2023) falls steadily through 2050, driven by rising competition from gas and renewables and stronger policies restricting coal use. Coal's share in TPED falls by more than half, to 11% in 2050, with absolute quantities consumed decreasing by more than 50%.

► The average real (constant 2022 dollar) Dated Brent crude oil price is expected to be about $74/barrel (b) during 2023-50 in the S&P Global outlook—an increase of over $10/bbl compared with the base case presented in *The National Energy Report 2021.* This upward shift in the expected price trajectory reflects a variety of factors putting additional pressure on producer break-even costs. In particular, supply chain issues have heightened inflation as the world continues to recover from COVID-19, armed conflict in Ukraine and the geopolitical fallout have resulted in a higher price "risk premium" while the negative impact of Western sanctions on Russian oil production longer term also removes a significant stream of lower-cost barrels from the global market. Finally, investors now require higher rates of return before launching major new upstream projects, since the ongoing global decarbonization drive weakens the overall global oil demand picture.

► One key consequence of new Western sanctions targeting Russian oil and product exports since 2022 has been to partition global markets between those who buy Russian barrels and those who do not. Western nations that have now generally banned the import of Russian barrels have ended up paying more on average for imports than countries such as India and mainland China—the main recipients of Russian oil redirected from European markets, at deeply discounted prices. Significantly, the countries without sanctions in place against Russia account for about two-thirds of the world's population and a growing share of the global hydrocarbon market. The G7/EU price cap regime, whereby these countries' maritime services are available to facilitate Russian oil and refined product exports so long as such sales occur below a specified price ceiling or cap, has contributed to the stability of Russian oil and product export volumes and thereby served to avert global oil price spikes while reinforcing market partition. Voluntary oil production restrictions by the OPEC+ coalition, of which Russia and Kazakhstan are both members, nevertheless continue to limit global oil supply and thereby exert upward pressure on prices.

► Global oil demand and supply growth are concentrated among non-OECD and OPEC countries, respectively, during the scenario period. On the demand side, the non-OECD share of global liquids consumption rises from 54.1% in 2022 to 68.1% in 2050 (and the Asia Pacific region remains the chief global center of oil demand growth). On the supply side, OPEC liquids output rises by 28% to 44 million b/d in 2050—lifting the OPEC share of total world liquids production from 34% in 2022 to around 44% in 2050. The three largest producers globally during the period out to 2050 are likely to remain the United States along with OPEC+ members Saudi Arabia and Russia (which accounted between them for over 30% of global liquids supply in 2022).

1 Global liquids (or oil) demand figures are presented as "total oil liquids," which includes crude oil as well as biofuels, liquid petroleum gases, other liquids (including natural gas liquids, gas to liquids, coal to liquids, asphalt, petroleum coke, waxes, lubricants, aviation gasoline, nonrenewable oxygenates, refinery additives and oil shale [kerogen]).

► Overall, the development of the national oil and gas sector has continued to serve Kazakhstan well. But the flip side of the coin of the economy's heavy reliance on hydrocarbon revenue is the vulnerability of macroeconomic trends to swings in global oil prices, as repeatedly demonstrated in recent years. Notably, both the contraction of Kazakh GDP in 2020 and subsequent rebound starting in 2021 largely paralleled world oil price trends, while the slowing of national GDP growth in 2022-23 reflected the deceleration of oil price growth in 2022 and price decline in 2023. Although energy sector recovery lifted the national economy in 2022-23, the energy sector has lagged various other sectors of the economy in the post-2020 rebound of investment in fixed capital, indicating relatively weak returns recently. Notwithstanding such concerns, the energy sector generally, and the hydrocarbon industry in particular, is expected to remain a key driver of Kazakh economic growth throughout the period to 2050: annual GDP growth is expected to slow over time, but still average 2.6% during 2023-50.

► Comparative analysis of upstream costs in oil-producing countries and an E&P attractiveness country rating developed by S&P Global indicate that Kazakhstan may struggle to compete with certain other international destinations for new foreign investment needed to help finance additional upstream development. The S&P Global cost curve methodology calculates a relatively high break-even price for a typical new Kazakhstan upstream project (in 2022), of about $67/bbl (i.e., for projects that would begin development over the next few years). For context, most of the new global crude production through 2040, for example, is expected to come from countries where projects break even at $50/bbl or less. Meanwhile, our latest quarterly E&P attractiveness rating placed Kazakhstan in only the 78th spot out of 112 countries, albeit the country's rating has improved somewhat over the course of the past 10 years; key factors accounting for Kazakhstan's relatively low rating include a comparatively high government tax take and correspondingly low rate of return for upstream investors in Kazakhstan.

1.2 General Trends in Primary Energy Demand

Global trends in the consumption of energy in the aftermath of the COVID-19 pandemic are being driven by an increasingly complex interplay of underlying forces that appear destined to dramatically alter the trajectory and composition of world energy demand over the next three decades. Primary energy demand is rebounding in the aftermath of the pandemic, but at the same time that the transition to lower-carbon forms of energy is gaining momentum. The uncertainties inherent in this transition are now compounded by a new element—geopolitical turbulence—with the disruption and subsequent reorientation of energy trade flows resulting from the conflict in Ukraine now placing energy security at the forefront of many countries' energy and broader economic agendas. These security concerns are shared both by countries that have depended on imports of fossil fuels to sustain their economies and those that rely on energy export revenues to finance significant portions of their national budgets.

A good starting point in efforts to envision where these trends may be leading is to assess the current structure of global primary energy demand (2021 and 2022) coming out of the pandemic. Clearly the effects of the pandemic are evident in the reduction and subsequent recovery of global economic activity: total real global GDP fell by 3.1% in 2020, followed by a strong rebound (6.0% growth) in 2021 and slower growth (3.1%) in 2022.[2] The trajectory of global primary energy demand was broadly similar, contracting by 3.9% in 2020, recovering strongly (4.9%) to the pre-pandemic level in 2021, with growth slowing (1.4%) in 2022 (see Table 1.1 Global primary energy demand by fuel type, 2019-23).

In that year oil (i.e., crude and condensate) continued to be the most widely consumed form of energy, accounting for 30.5% of primary energy demand, followed by coal (26.8%) and natural gas (22.9%). The shares of the other fuels in total global energy demand were decidedly smaller, accounting for 5% or less each.

Examination of relative changes in demand for each of the fuels over the period 2021–22 is particularly illustrative, both of near-term disruptions from the Russia-Ukraine conflict as well as the likely resilience of longer-term trends. The modest growth in global oil (liquids) consumption is consonant with the picture of a gradual recovery in activity as the impacts of the pandemic recede, but the drop in natural gas consumption clearly reflects reduced European consumption of the fuel in 2022 as Russia reduced supplies to the Continent,[3] and weak Chinese demand as the pandemic impact persisted later there than in most other parts of the world. European and global spot gas prices surged in anticipation of tight winter 2022 supply, further depressing demand. As a result of the anomalous gas supply picture and resulting high prices, the global trend toward net coal-to-gas switching in power generation and industry was temporarily reversed in 2022, with coal consumption increasing worldwide by 1.4%. Another factor contributing to the rise of regional coal demand in Europe and Eurasia (e.g., Russia) was a warmer and drier spring and summer 2022. This reduced hydroelectric power generation and in Europe nuclear power generation as well, as sources of cooling water were threatened by falling river levels; coal-fired capacity disproportionately received the call to serve as the back-up.[4]

Despite these 2022 deviations in global primary energy demand, other developments demonstrated the persistence or even acceleration of longer-term trends. Demand for renewable energy exhibited double-digit gains (albeit from a small base), well above the 1.4% growth in overall primary energy demand, continuing the momentum of the global energy transition toward renewable electricity and fuels; generation of electric power by wind increased by 14.1% globally in 2022 and solar-generated power increased by 26.7%.

2 S&P Global Market Intelligence, Economics and Country Risk, *Global Executive Summary*, 21 June 2023.

3 According to the International Energy Agency, natural gas demand in the European Union fell in 2022 by 55 Bcm, or 13%, its steepest drop in history; see https://www.iea.org/commentaries/europe-s-energy-crisis-what-factors-drove-the-record-fall-in-natural-gas-demand-in-2022.

4 See S&P Global Commodity Insights, Russia Watch, *Damage Control: How is Russia's energy industry adapting to intensified Western sanctions and new domestic political and economic constraints?* March 2023, p. 50.

Table 1.1 Global primary energy demand by fuel type, 2019-23 (MMtoe)

	2019	2020	2021	2022	2023*	Δ%, 2021-22
Total	**14,685**	**14,115**	**14,801**	**15,007**	**15,138**	**1.4**
Oil	4,624	4,188	4,453	4,584	4,694	2.9
Natural gas	3,358	3,307	3,460	3,431	3,397	-0.8
Coal	3,914	3,809	3,963	4,020	3,924	1.4
Hydro	364	373	367	371	388	1.1
Nuclear	728	700	729	699	711	-4.1
Renewables	331	364	408	465	545	14.0
Modern biomass	745	751	787	794	849	0.9
Other**	620	623	634	643	631	1.3

Notes: *Estimate. **Includes traditional biomass, solid waste, ambient heat, and net trade in electricity, hydrogen, and heat.
Source: S&P Global (Energy and Climate Scenarios).

1.3 Outlook for the Global Energy Mix to 2050

The long-term outlook for world primary energy demand is based on S&P Global's proprietary base-case energy scenario, known as Inflections®. Inflections models future world energy demand and related greenhouse-gas emissions out to the year 2050 on the basis of the following general assumptions:

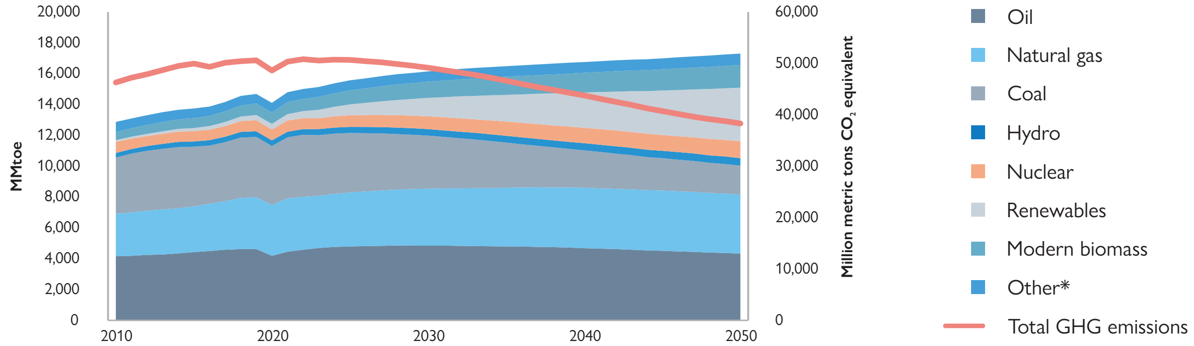
- ***Fundamental turning points*** in international relations, national politics, markets and individual choice and behavior accelerate the global energy transition faster than previously anticipated.
- **Greater geopolitical instability** drives countries to seek more political, economic and energy security and independence. The global landscape becomes more divided and international relations become more opportunistic and transactional.
- ***National security interests become closely linked with energy security, which is pursued in different ways by countries,*** depending on domestic politics, energy resource mix, levels of import dependency, and institutional capabilities to alter existing energy systems. Energy security in Inflections largely means pursuit of "all of the above" (fossil fuels [short-to-medium term], clean technology and end-use efficiency [medium-to-long term]).
- ***Key countries pursue industrial policies to develop competitive advantages in clean energy technologies*** and related industries in what is considered a new type of "arms race."
- ***Successful implementation of policies and strategic goals is mixed across the world, affected by politics, market constraints, and practical barriers.*** Progress in the evolution of energy markets and a pathway to a lower-carbon future is significant, but does not meet expectations, leaving most long-term clean energy and climate goals and aspirations unmet by 2050.[5]

Figure 1.1. presents the Inflections outlook for the global energy mix to 2050, accounting for continuing decarbonization efforts, the resulting shifts in investments among the varied energy carriers, and S&P Global's basic assumptions concerning national government policy initiatives (see Figure 1.1 Global primary energy demand and GHG emissions: Inflections). The following key, overarching trends can be identified:

- Over the period 2022–50, total primary energy intensity (million tons of oil equivalent [MMtoe] of primary energy consumed per $US million GDP) declines at a compound annual rate (CAGR) of -2.0% (see Figure 1.2 Primary energy intensity of GDP), while total primary energy demand grows by 15% (to 17,303 MMtoe; CAGR of 0.5%). This occurs despite a doubling of global GDP and population growth of almost two billion people. In short, the effect of GDP growth in increasing energy demand is offset by an approximate doubling of the rate of efficiency improvements, relative to the 1990–2021 trend.
- During the 2030s and 2040s, a mix of government policies and actions by corporations pushes a steady shift toward lower carbon energy across most major economies. Fossil fuel consumption is on a consistently downward path, while market penetration by renewables and electric vehicles (EVs) is a story of steady growth.
- Electrification is the main element in primary energy demand growth through 2050, with renewables greatly outpacing fossil fuels in power generation and transportation. Non-hydro renewables account for over 60% of global power generation capacity by 2050.

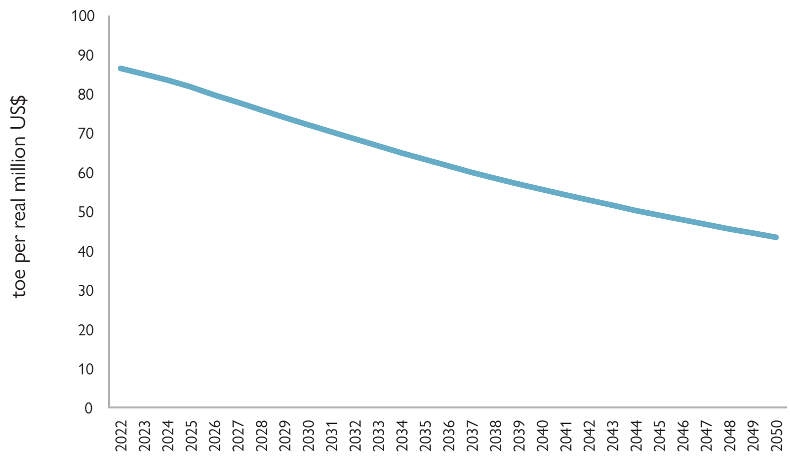
5 S&P Global, Energy and Climate Scenarios/Webinar, *Energy and Climate Scenarios 2023 Update: Assumptions, narratives, and preliminary results*, 17 May 2023, p. 17; S&P Global, Strategic Report, Energy and Climate Scenarios, *Inflections 2023–50: The S&P Global Commodity Insights base-case scenario of the energy future*, July 2023. In addition to the base-case scenario Inflections, S&P Global models four other global energy and climate scenarios—Discord, Green Rules, Accelerated Carbon Capture and Storage (ACCS), and Multitech Mitigation. Discord assumes that a confluence of crises worsens geopolitical fragmentation (a tendency in international relations toward a "friend vs. foe" alignment of like-minded nations) and weakens the resolve for collective climate action, resulting in much less progress toward emissions reduction than in Inflections. Green Rules assumes that energy security concerns mobilize strong long-term government actions that align energy security and energy transition measures, leading to more substantial emissions reduction than in Inflections, but still not sufficient for the world to reach net zero by 2050. ACCS and Multitech Mitigation are two 2050 net-zero scenarios based on widespread adoption of carbon capture and storage economy-wide (ACCS) and strong energy efficiency measures and electrification based on renewables, hydrogen, and nuclear power (Multitech Mitigation).

Figure 1.1 Global primary energy demand and GHG emissions: Inflections



Notes: *Includes traditional biomass, solid waste, ambient heat, and net trade of electricity, hydrogen, and heat.
Source: S&P Global Commodity Insights.

Figure 1.2 Primary energy intensity of GDP (2022-50)



Source: S&P Global Commodity Insights.

The outlook for individual energy sources can be summarized as follows:

- ***Oil and condensate (liquids)*** demand rebounds over the near term as the world recovers from the confluence of crises (pandemic, military conflict in Ukraine, inflation) in the early 2020s. Liquids demand globally peaks in the early 2030s, and gradually falls back to 2022 levels by the early-to-mid-2040s. Although oil loses market share and total demand falls, it remains the largest contributor to total primary energy demand (TPED) in 2050 (falling to 25% of TPED from 31% at present).
- ***Natural gas*** will play a key role in transitioning toward a lower-carbon future in key markets in developed and developing countries, whether through back-up to renewables in power markets, rising low-emission "blue" hydrogen production, or continued use in hard-to-decarbonize sectors such as heavy industry. The Inflections scenario sees gas continuing to play largely a bridge role, with robust demand through the late 2030s, before plateauing thereafter to the end of the forecast period (i.e., gas demand reaches a maximum around the year 2040). The share of gas in TPED in 2050 (22%) is virtually the same as at present (23%), although the volume consumed (3,833 MMtoe) is expected to be about 12% higher.
- ***Coal*** demand rebounded in 2021 as a result of post-pandemic recovery and in 2022 as countries pursued short-term energy security measures to address the crisis in gas supply resulting from the Russia-Ukraine conflict. But this rebound will be short-lived, as coal enters a long-term downward demand trajectory through 2050, driven by steadily rising competition from gas and renewables and stronger policies restricting coal use. Coal's share falls by more than half, from 27% in 2022 to 11% in 2050, with absolute quantities consumed decreasing by more than 50%. This will require a proactive policy response for regions that have traditionally relied upon the production and consumption of coal as a basis for industry and power generation, as coal's decline is expected to adversely impact the economic prospects of coal companies in these regions, with related effects on the social welfare of their populations.
- ***Renewables.*** By the 2030s, wind and solar projects are lower cost than fossil fuel generation on a levelized cost of energy (LCOE) basis in most parts of the world—even without subsidies or government protection. However, rapid growth of renewables and EV penetration of road transportation continue to face challenges as demand for strategic materials like lithium and copper often outpaces supplies. There are also supply chain issues related to batteries, solar cells, and

wind turbines, as overreliance on particular markets (e.g., China) takes time to overcome. Over time, policy and market responses gradually contribute to expanding sources of key raw materials and diversifying wind and solar photovoltaic (PV) manufacturing and supplies. Eventually, decentralization of manufacturing occurs as part of a broader reshoring and onshoring trend in many markets. The combination of all these factors results in higher costs for renewables, but not to the extent that it significantly curtails growth. Over the period 2022–50 renewable energy demand increases more than sevenfold, at a CAGR of 7.4%, so that by 2050 its share of TPED (20%) trails only oil and gas among the primary energy sources.

- ***Nuclear and hydroelectric*** power will remain vital sources of zero-emission power generation in the new energy system, although their shares in total primary energy demand in 2050 (6% and 3%, respectively) will not change appreciably from at present (5% and 2%, respectively). Nonetheless they will be larger overall, increasing with TPED. By 2050 primary energy demand for nuclear power will be 57% greater than at present, and demand for hydro will be 33% greater.
- The share of ***modern biomass*** (including biofuels, biogas, and processed waste wood) in TPED will nearly double from the current level (5%) by 2050 (9%), as the trend toward recycling of plant and animal waste for the production of renewable fuels gains momentum. However, the dedicated use of scarce land strictly for fuel production (given the increasing opportunity cost of producing fuel instead of food on such land) is expected to encounter limits, so the growth trend tapers toward the end of the forecast period.
- In contrast to modern biomass, the share of "***other***" forms of primary energy (which includes direct combustion of wood and animal waste as well as net trade in hydrogen in primary energy) remains relatively constant, at 4%. This appears to reflect the countervailing effects of a gradual decrease in direct combustion of wood and animal waste in developing countries—whose GHG emissions per unit of energy exceed even that of coal—and a slow increase in net trade in hydrogen, electricity, and heat in TPED.

1.4 World Oil Market Trends and the Implications for Kazakhstan

This section provides an overview of global oil price trends and the evolution of our price outlook to 2050 since the previous edition of *The National Energy Report*, based on changes in global oil supply and demand fundamentals and upstream investment dynamics. It then examines the implications for Kazakhstan's economy and upstream investment development.[6]

1.4.1 World oil prices: The supply cost curve has shifted upwards

Geopolitical factors became a more critical driver of prices for oil along with other commodities in the wake of the February 2022 expansion of armed conflict in Ukraine and given the ensuing expansion of Western sanctions against Russia—exacerbating new inflationary pressures that had already sent oil prices sharply upward starting in 2021.[7] Although prices so far in 2023 have trended lower than in 2022, the S&P Global outlook is now for a significantly higher average long-term world oil price compared with our outlook at the time of *The National Energy Report 2021*. Supply chain issues and heightened inflation continue to put upward pressure on producer break-even costs—and therefore prices as well—while companies are also seeking higher rates of return to offset the additional upstream investment risks amid the global decarbonization push. Another factor contributing to higher prices is the negative impact of Western sanctions on Russian oil production longer term, as that removes a significant stream of lower-cost barrels from the global market. Periodic OPEC+ crude oil output restrictions are also likely to buoy prices during various years of the scenario period. The net result is likely to be an average real (constant 2022 dollar) Dated Brent price exceeding $70/bbl during the scenario period to 2050—over $10/bbl above our price outlook in 2021. In short, a higher long-term price environment is now seen as necessary to incentivize sufficient long-term supply, notwithstanding the expected peak in global oil liquids demand in the early 2030s in our current outlook.[8]

1.4.1.1 Recent global oil price and market developments

The 2021 surge in the average real Dated Brent price, by 63% to $76/bbl ($71/bbl nominal), was followed by a 34% price jump in 2022, to $101/bbl. Supply chain constraints contributed to much of this price rise starting in 2021, as the global economy rebounded from the 2020 COVID-19 quarantine measures, while another key factor since February 2022 has been global market disruptions following Western nations' adoption of sanctions targeting Russian oil and product exports. The OPEC+ group's continued voluntary curtailment of crude oil production levels provided price support throughout this period as well. Dated Brent reached a monthly high during 2022 of about $124/bbl in June, but during most of the second half of 2022 was under $100/bbl, and prices so far in 2023 have fluctuated in approximately the $75-$95/bbl range. The price downturn in the second half of 2022 and first part of 2023 reflected the resilience of overall Russian oil export volumes—largely redirected from European to "East of Suez" markets—along with relatively weak demand-side fundamentals given a slowdown of global economic

6 Here and elsewhere, the term "oil" as used in this report is typically shorthand for overall liquids volumes including both crude oil and gas condensate as well as other types of liquid fuels. Analysis of global oil trends in *The National Energy Report 2023* provides oil volumes in barrels, whereas official statistics of Kazakhstan and other Eurasian countries typically report regional oil volumes in metric tons. When referencing Kazakh oil volumes specifically, however, these are generally provided in metric tons followed by barrel-equivalent estimates in parentheses. Separate metric ton-barrel conversion ratios are used for major individual Kazakh oil streams where applicable. But for aggregated or undifferentiated oil volumes (production, refining, consumption, and export streams), barrelization of these volumes (or capacities) is based on an average 7.3 barrel-per-metric-ton ratio. For more on Kazakh ton-barrel conversion issues, see S&P Global Commodity Insights, Insight, *OPEC+ Agreement Accentuates Challenges of "Barrelization" of Oil Production for Russia, Kazakhstan, and Azerbaijan*, September 2020.

7 The term "Western" as used in this report is shorthand for the loose coalition of countries that have enacted sanctions against Russia in response to the armed conflict in Ukraine and is not limited in a geographic sense—it includes countries of the Asia Pacific region such as Japan and Australia along with EU member nations, the United Kingdom, Switzerland, Norway, the United States, and Canada.

8 All dollar prices in this report refer to US dollars unless otherwise indicated.

growth.

The G7/EU price cap mechanism has contributed to stability of Russian oil as well as product export volumes. The G7/EU decision to make these countries' maritime services available to facilitate Russian oil and refined product sales so long as the price does not exceed a specified level has contributed to the stability of Russian export volumes; i.e., the alternative option of a blanket ban on provision of these maritime services as originally considered would have resulted in a major curtailment of Russian exports given the absence of readily available replacements for many G7/EU services. The price cap regime, introduced in December 2022 for Russian crude oil and February 2023 for refined products—corresponding to the EU schedules for imposition of outright bans on the import of Russian crudes and products, respectively—was designed to minimize any potential global reduction of Russian export volumes and resulting price spikes, while simultaneously limiting Russian revenues from such sales. Under terms of the price cap regime, third party countries importing Russian crude and products can contract with Western maritime service providers to conduct this trade if the oil or product sales price falls below the specified caps, and these price ceilings are reviewed periodically by the sanctioning nations with the aim of ensuring that Russian oil and products continue to sell at a significant discount in global markets.

The price caps were initially set as follows, and remain at these same levels for now:

- $60/bbl for crude oil
- $100/bbl for products that trade at a premium to crude oil, including diesel (Russia's largest single product export stream), gasoline, and jet kerosene
- $45/bbl for products that trade at a discount to crude oil, including fuel oil and naphtha.

The Western sanctions have led to a partitioning of the global oil and refined product markets (for the foreseeable future) between those who buy Russian barrels and those who do not. The global oil and products market as it was known since the 1990s, basically ceased to exist in 2022-23. Most of Russia's sales before 2022 were to Western nations that have now generally banned the import of Russian barrels (with a few exceptions). Countries that embargoed Russian volumes ended up paying more for imports, partly due to higher logistical costs. In contrast, India and mainland China in particular have been keen to import discounted Russian barrels shunned by the EU and other traditional buyers. Altogether, countries without sanctions in place against Russia account for about two-thirds of the world's population and a growing share of the global hydrocarbon market, although relatively few of these nations can be considered close partners of Russia.

The new geopolitical realities have also had some negative knock-on effects on the price of Kazakhstan's primary export crude grade, CPC Blend, as well as other Kazakh crude oil exports transiting Russian territory. The average CPC Blend discount to Dated Brent widened significantly in 2022, as CPC exports were curtailed amid shipping constraints and rising associated risks. CPC Blend price risks arising from the armed conflict in Ukraine subsequently eased but remain a concern to buyers; as a result, the spreads have recently remained wider than historical levels. Meanwhile, Kazakh oil exported via the Transneft pipeline marine terminal outlets in the Baltic Sea (Ust-Luga) and Black Sea (Novorossiysk) were initially subject to the same sort of steep discounts as Russia's Urals Blend, but Kazakhstan subsequently managed to sell these export volumes at a premium to Urals by rebranding them in June 2022 as Kazakhstan Export Blend Crude Oil (KEBCO), and thereby differentiating Kazakh oil from Russian oil (though the quality of KEBCO is identical to that of Urals). Indeed, after trading at a discount to Brent during the second half of 2022 and first part of 2023, KEBCO has also traded at a premium to Brent in recent months (even as Urals has remained at a discount to Brent, albeit a narrower discount than before). This positive dynamic partly reflects the general tightness of sour barrels in global oil markets due to the OPEC+ reduction of collective crude oil output; Saudi Arabia is playing the lead role in the latest OPEC+ reductions and since it is a producer of relatively sour barrels the net result is to make such crude streams scarcer, boosting their prices generally worldwide, while Russia has also announced a series of new cuts this year that limit the availability of Urals Blend in world markets. In addition, European refiners who were dependent on Urals prior to sanctions have scrambled to find crudes of similar quality.

1.4.1.2 Near-term and long-term price scenarios

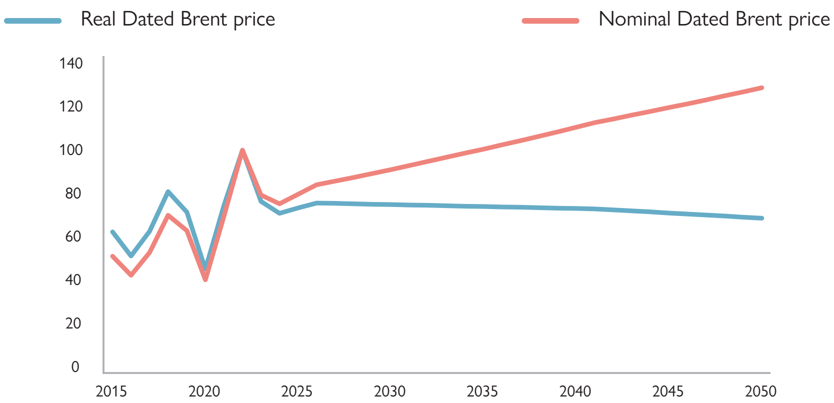
In our current outlook, world oil prices drift upwards in the second half of 2023, before weakening slightly (in real terms) in 2024. However, prices are likely to remain relatively volatile going forward, particularly given the dynamic situation with respect to key variables impacting oil balance fundamentals, especially Chinese demand and the production trajectories of Russia as well as Saudi Arabia and the United States.

Key assumptions underlying our expectation for price strengthening in the second part of 2023 include:[9]

- ***Global oil demand growth is relatively robust, concentrated primarily in mainland China.*** Mainland China has contributed more than any other country to 2023 world liquids demand growth, though some mixed macroeconomic signals raise questions about the magnitude of mainland China's growth, both for the economy and oil demand. In the United States, tighter credit will continue to restrain economic growth, but the likelihood of a recession has dropped.
- ***OPEC+ actions reduce the potential for supply surplus, but substantial production growth outside OPEC+ is a countervailing force limiting the price upside.*** In autumn 2022, the OPEC+ countries began lowering their collective crude oil output targets in a series of deals (Kazakhstan agreed to an additional 78,000 b/d reduction as part of one of these accords, in April 2023). Meanwhile, however, liquids production by several countries outside OPEC+ grows robustly in 2023. This year, the United States is again the leading source of higher supply, but there are many other notable contributors as well: Canada, Brazil, Guyana, Norway, mainland China, and Argentina.

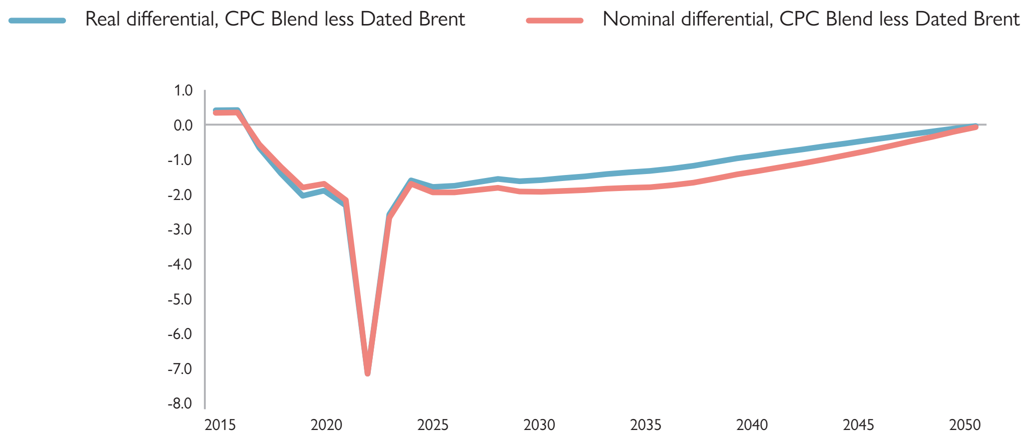
9 S&P Global Commodity Insights, Scheduled Update, *Global Crude Oil Markets Short-Term Outlook: The Quiet Surge: Supply growth outside OPEC+*, June 2023.

Figure 1.3 Long-term crude oil price outlook ($/bbl)



Notes: Real 2022 dollars per barrel.
Source: S&P Global Commodity Insights, Argus Media Limited (for historical prices).

Figure 1.4 Long-term outlook for CPC Blend differential to Dated Brent ($/bbl)



Notes: CPC Blend Med CIF price; real 2022 dollars per barrel.
Source: S&P Global Commodity Insights, Argus Media Limited (for historical prices).

Whereas our long-term price base case at the time of *The National Energy Report 2021* was for Dated Brent to average around $60/bbl in real terms during the period out to 2050, our current outlook is for an average between $70/bbl and $80/bbl. This price appears adequate to incentivize sufficient long-term supply (see Figure 1.3 Long-term crude oil price outlook). Break-even costs have risen sharply, as inflation, material prices, and supply chain issues have all put upward pressure on costs. Companies are seeking higher rates of return on extraction efforts since risks are rising for upstream investment, as a weakened global oil demand picture clouds the long-term outlook.[10]

With respect to CPC Blend differentials versus other international crude grades, the outlook is for some reduction of the discount seen recently, given such factors as strong European refinery demand for CPC Blend as a replacement for Urals (see Figure 1.4 Long-term outlook for CPC Blend differential to Dated Brent).

1.4.2 Global oil balance outlook

The longer-term S&P Global price outlook reflects our key assumptions about the trajectories and geography of global oil demand and supply during 2023-50 (see Table 1.2 Outlook for world oil (liquids) balance to 2050).[11] S&P Global expects global oil (liquids) demand to peak during the first half of the outlook period and then begin a gradual decline, but it is a "long goodbye" as different national policies and actions slow the global progression toward alternatives and ongoing economic growth upholds oil use in emerging markets. Meanwhile, relatively robust OPEC production accounts for a growing share of global oil supply as both Russian and US production enter long-term decline trajectories. The removal of comparatively low-cost Russian barrels from the supply curve is also supportive of price, insofar as these must be replaced by alternative barrels worldwide that are largely more expensive to produce (as discussed below in

10 See S&P Global Commodity Insights, Scheduled Update, *Europe, CIS, and Africa Crude Oil Markets Long-Term Outlook: Q2 2023,* June 2023, and S&P Global Commodity Insights, Scheduled Update, *The Long-term Oil Price Environment Now Looks More Expensive,* June 2022.

11 Various 2022 baseline numbers for our 2050 global oil supply and demand scenarios consist of S&P Global outlooks for 2022 results in the absence of final year-end data.

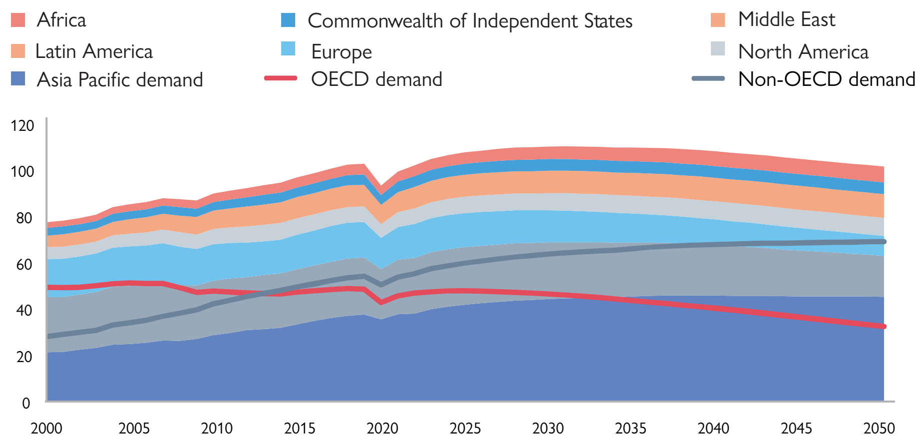
Table 1.2 Outlook for world oil (liquids) balance to 2050 (million b/d)

I. World liquids demand[1]	2020	2025	2030	2035	2040	2045	2050
North America	21.6	24.7	24.3	23.2	21.7	19.7	17.5
United States[2]	17.9	20.5	20.0	19.0	17.6	15.8	13.7
Canada	2.2	2.4	2.3	2.3	2.1	2.0	1.9
Europe	13.4	14.7	13.8	12.4	11.0	9.7	8.6
OECD Asia	7.3	7.8	7.7	7.3	6.7	6.1	5.6
Non-OECD Asia	28.0	33.8	36.4	37.9	38.8	39.1	39.5
China (mainland)	14.8	18.0	18.8	18.9	18.7	17.9	17.3
India	4.8	5.9	6.9	7.6	8.1	8.7	9.6
Non-OECD Asia excl. China and India	8.4	9.9	10.7	11.4	12.0	12.4	12.6
Latin America	5.8	7.0	7.4	7.7	7.8	7.8	7.8
Middle East	8.3	9.5	9.6	9.8	10.2	10.3	10.2
Commonwealth of Independent States	4.2	4.8	5.0	5.0	5.0	5.1	5.0
Africa	4.0	4.9	5.4	5.9	6.3	6.6	6.8
Total world liquids demand	**92.8**	**107.1**	**109.6**	**109.2**	**107.5**	**104.3**	**100.9**
Asia Pacific demand	35.4	41.6	44.1	45.2	45.5	45.2	45.1
OECD demand	42.6	47.6	46.2	43.4	40.0	36.1	32.2
Non-OECD demand	50.2	59.5	63.4	65.8	67.5	68.2	68.7
II. World liquids production							
Non-OPEC Crude[3]							
North America	16.8	20.8	21.1	20.3	18.3	17.1	15.7
United States[2 4]	10.7	13.7	14.0	13.5	11.7	10.9	10.0
Canada[4]	4.4	5.3	5.5	5.3	5.0	4.8	4.4
Mexico	1.7	1.8	1.6	1.6	1.5	1.4	1.3
Commonwealth of Independent States[4]	14.0	13.3	12.4	12.2	11.7	10.8	9.7
Latin America	5.3	5.9	7.0	7.2	7.5	6.8	5.8
Brazil	3.1	3.4	4.2	4.4	4.5	4.4	3.7
Europe	3.2	3.2	2.4	2.0	1.7	1.4	0.8
Asia Pacific	6.4	6.2	5.4	5.2	4.6	4.0	3.5
Africa	1.5	1.4	1.5	1.6	1.8	1.7	1.5
Middle East	1.8	2.0	1.7	1.4	1.2	0.9	0.7
Total Non-OPEC crude	49.1	52.8	51.6	49.9	46.7	42.6	37.6
Non-OPEC condensate and NGLs	10.0	11.4	12.2	11.9	11.0	10.4	9.7
Total Non-OPEC liquids production	**59.1**	**64.2**	**63.8**	**61.7**	**57.7**	**53.0**	**47.3**
OPEC crude[3]	26.4	30.3	31.1	31.6	33.4	34.8	37.3
OPEC condensate and NGLs	5.0	5.7	6.8	7.4	7.5	7.4	7.0
Total OPEC liquids production	**31.4**	**36.0**	**37.9**	**38.9**	**40.9**	**42.1**	**44.2**
Processing gains	2.1	2.5	2.5	2.5	2.5	2.4	2.3
Global biofuels and other liquids[5]	3.4	4.4	5.4	6.0	6.5	6.7	7.1
Total world liquids production	**96.0**	**107.1**	**109.6**	**109.2**	**107.5**	**104.3**	**100.9**
Total crude oil production	75.5	83.1	82.7	81.4	80.1	77.4	74.9
III. Inventory dynamics							
Total liquids inventory change[6]	3.3	0.0	0.0	0.0	0.0	0.0	0.0

Notes: Mexico is included in North America.
1 Includes biofuels and other synthetic oil.
2 The United States includes 50 states, District of Columbia, and other US territories excluding Puerto Rico.
3 The split of OPEC and non-OPEC countries is based on the member status as of July 2021.
4 Includes condensate.
5 Biofuels include US and Brazilian ethanol supply. Other liquids category includes gas-to-liquids (GTL), coal-to-liquids (CTL), nonrenewable oxygenates, refinery additives, and oil shale (kerogen).
6 A positive number indicates a stock build. A negative number indicates a stock draw.

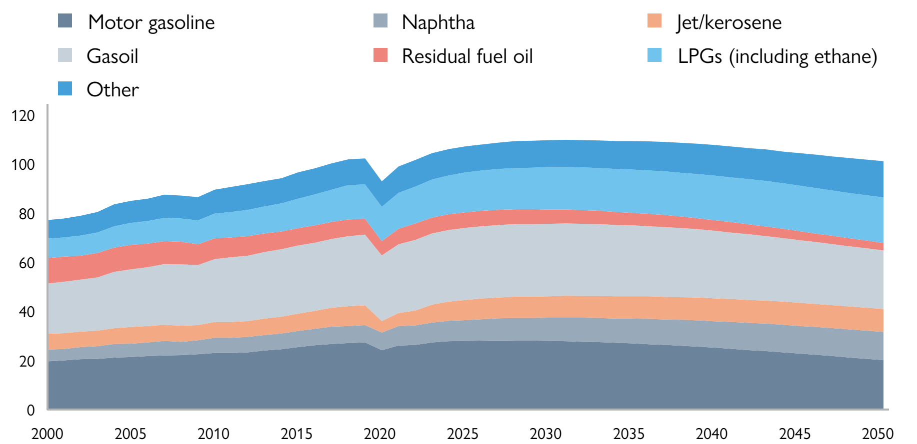
Source: Historical data from the International Energy Agency, US Energy Information Administration, national statistical agencies; projections from S&P Global Commodity Insights.

Figure 1.5 World oil (liquids) demand outlook by region (million b/d)



Notes: Demand calculation includes biofuels and other synthetic oil; Mexico is included in North America.
Source: Historical data from the International Energy Agency, US Energy Information Administration, national statistical agencies; projections from S&P Global Commodity Insights.

Figure 1.6 World oil (liquids) demand outlook by refined product to 2050 (million b/d)



Notes: "Other" category includes asphalt, petroleum coke, waxes, lubes, aviation gasoline, and miscellaneous products.
Source: Historical data from the International Energy Agency and US Energy Information Administration; projections by S&P Global.

more detail, Russian oil production remains substantial during 2023-50, but contracts significantly from the 2022 level).[12]

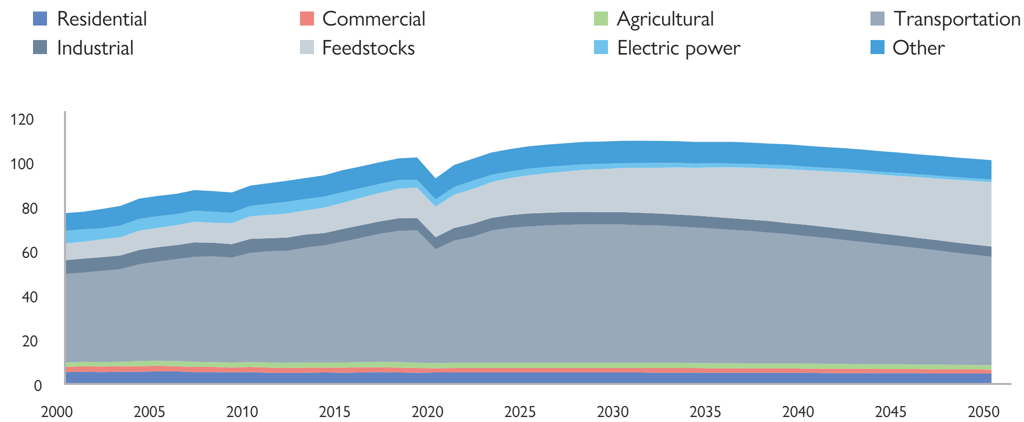
The following sections discuss key drivers of our demand and supply outlooks in more detail.

1.4.2.1 Global oil demand

In Inflections, global liquids demand rises from around 102 million b/d in 2022 to an early 2030s maximum of about 110 million b/d, before declining to around 101 million b/d in 2050. The non-OECD countries' aggregate oil consumption, however, remains on a growth trajectory during this period, rising by 25% altogether to 69 million b/d, while OECD demand contracts by 31% to 32 million b/d. Thus, the non-OECD share of global liquids consumption rises from 54.1% in 2022 to 68% in 2050 (see Figure 1.5 World oil (liquids) demand outlook by region, Figure 1.6 World oil (liquids) demand outlook by refined product to 2050, and Figure 1.7 World oil (liquids) demand outlook by sector to 2050).

12 For example, S&P Global estimates average 2040 Russian oil producer costs for new projects, in terms of the Brent break-even price, at around $45 per barrel; this compares with break-even costs averaging over $50 per barrel for a large portion of potential global oil supply from new projects in 2040.

Figure 1.7 World oil (liquids) demand outlook by sector to 2050 (million b/d)



Notes: "Transportation" category includes biofuels; "Other" category includes Includes energy sector uses, distribution losses, and statistical differences (negative numbers may indicate use of synthetic fuels); IEA historical data are based on annual data, which often vary slightly from aggregated IEA monthly data.

Source: Historical data from the International Energy Agency and US Energy Information Administration; projections by S&P Global.

During the period to 2030, key factors include the following:

- A post–COVID-19/Ukraine crisis bounce in oil (liquids) demand soon tempers as high prices and concerns over energy security limit oil demand growth through the decade, with aggregate expansion averaging less than 1% per year from 2022 to 2030 (the weakest period of growth over the past 20 years and a harbinger of "peak" oil demand to come).
- Demand growth is driven largely by mainland China and emerging market countries, while demand in developed economies plateaus and then declines; high prices in the early 2020s sharpen concerns over fossil energy dependence.
- This dovetails with a new wave of electric vehicles (EVs) entering the market and rising sales in key markets.
- In 2030, global demand is around 110 million b/d, 8% above the 2022 level.

During 2030-50, key global oil demand dynamics include:

- The accelerating energy transition leads to a peak in global oil (liquids) demand by the early 2030s.
- The postpeak decline in global demand is more rapid than in our previous outlook, as key consuming markets chase net-zero goals, bolstered by newly heightened concerns around energy security.
- Motor gasoline consumption contracts the most, as EV penetration in light vehicle (LV) road transportation accelerates, driven by zero-emissions vehicle (ZEV) mandates in different countries and the world's major automakers committing to the transformation of their output away from gasoline- and diesel- propelled LVs and steadily increasing EV manufacturing and sales.
- EV sales also grow in emerging-market economies (driven in many places by rising sales of electric two-wheeled vehicles), outpacing sales in OECD countries by the 2040s.
- Notwithstanding significant contraction of gasoline consumption, the transportation sector remains the single largest component of oil demand throughout the outlook period, and in 2050 global motor gasoline consumption still amounts to around 20 million b/d in the base case, while transport diesel demand is equivalent to about 16 million b/d and jet/kerosene demand is roughly 9 million b/d.
- Beyond transportation, the practicality of petrochemical products—and plastics in particular— supports their continued use over the outlook period.
- By 2050, global oil (liquids) demand is approximately 101 million b/d, nearly the same as in 2022, but 8% below the global maximum of the early 2030s.

Major oil demand variations among regions in the S&P Global base case include continuing concentration of global demand growth in Asia Pacific markets (supplied increasingly from outside the region), alongside further contraction of European demand, the onset of long-term US oil demand decline by the late 2020s and moderate growth of demand in Eurasia:

- ***Asia Pacific region.*** Asia Pacific markets register a net oil demand rise of 19% during 2023-50, to 45 million b/d in our outlook. But dynamics within the region continue to vary widely. Non-OECD Asian demand increases by 31% to 39 million b/d, reflecting expansion of Indian demand in particular (by 77%, to 10 million b/d). Mainland China, with liquids demand of 16 million b/d in 2022, remains the chief non-OECD Asian market by far, but Chinese oil demand plateaus at around 19 million b/d in the late 2030s and falls to around 17 million b/d in 2050, so it only grows by 10% altogether during 2023-50. In contrast, OECD Asian oil demand drops 27% to 6 million b/d during the same period, reflecting the ongoing structural decline of Japanese oil demand in particular. At the same time, non-OPEC Asia Pacific crude oil production falls overall by 45% to 4 million b/d during 2023-50 in the outlook.

- ***Europe.*** Oil demand in Europe (currently Kazakhstan's primary oil export market) continues to contract in the S&P Global base case, but Europe remains highly dependent on imports to meet remaining demand given the simultaneous trend of an ongoing fall in indigenous crude oil production. European liquids demand drops overall by 41% to 9 million b/d during 2023-50, while crude oil production (essentially North Sea output) is expected to contract by 74%, leaving total indigenous output at only around 1 million b/d in 2050.
- ***North America.*** After reaching a maximum of around 25 million b/d in 2025, total North American liquids demand slowly contracts to 17 million b/d in 2050, for an overall decline during 2023-50 of 27%.
- ***Eurasia.*** Liquids demand among the Eurasian countries is expected to rise to a plateau of around 5 million b/d during the 2030s and 2040s, for a net increase during 2023-50 of 8%. As discussed in more detail below (see Chapter 3), the upcoming establishment of a Single Market among members of the Eurasian Economic Union (EAEU) implies a further liberalization of prices across EAEU members states that will tend to limit product demand growth in markets such as Kazakhstan's where prices are currently artificially low (compared with product consumption levels in a scenario without such market integration).

1.4.2.2 Global oil supply

Throughout the outlook period, oil reserves growth globally and in Kazakhstan, along with production growth, is likely to remain challenged by limited investment in exploration and field development as companies focus on capital discipline and return on investment, while confronting ESG (environment-safety-governance) concerns.[13] Exploration spending contracted markedly overall worldwide during the past ten years, and competition for remaining E&P investment is intense. Global E&P capex fell 57% over 2014-20; a 2021 rise still left spending well below pre-pandemic levels, while E&P capex finally surpassed pre-pandemic levels in 2022, when such spending totaled about half a trillion dollars (see Figure 1.8 Outlook for world upstream E&P spending). The growth in spending in 2021-22 is a predictable response to a stronger oil price environment, as well as upstream cost inflation, and inflation remains a key factor in an expected 11% rise in global upstream capital expenditure to $565 billion in 2023; 5% of the anticipated 2023 increase will come from cost inflation alone.[14] The rate of global spending growth and E&P activity is expected to slow beyond 2023, but will remain substantial. Above all, this reflects the imperative for new discoveries and production streams to sustain supply at levels necessary to meet world demand in coming decades given ongoing natural decline at producing fields. The aggregate global base decline rate during the outlook period, including fields that already are in decline as well as fields that are currently ramping up or at plateau, is forecast at about 3% per year. The call on new crude and condensate production is about 31 million b/d by 2040, for example, or nearly 40% of 2022 world output. At the same time, key signposts point to companies' increased emphasis on more selective exploration efforts oriented towards "low risk" opportunities.[15]

Although access to financial resources needed to fund new hydrocarbon projects is likely to remain challenging amid the ongoing energy transition, our (base case) Inflections scenario to 2050 is one in which global lenders nevertheless extend credit on the scale needed to bring on stream the major additional new E&P projects required to both offset depleting fields and meet incremental oil demand; i.e., growing oil demand globally during the first part of the scenario period and a continued rise in oil demand within numerous individual countries during subsequent years. The capital discipline now in vogue, though, is likely to increasingly limit oil companies' scope for spending to those projects that promise the best returns on investment—and, preferably, returns in the near to medium term rather than longer term—but the Inflections investment climate remains more favorable to E&P activity than that found in our alternative scenarios (in our Green Rules scenario, in contrast, financing for hydrocarbon projects is more constrained and new upstream projects are at greater risk, reflecting the accelerated decarbonization efforts and reduced call on hydrocarbons overall in this outlook). At the same time, the Inflections scenario is a world in which investors will also tend to give preference to those projects that can deliver lower carbon, higher value oil production in more sustainable and efficient ways than before.

The mix of total liquids supply also undergoes significant changes during the outlook period in terms of both composition and the geography of production (see Figure 1.9 Outlook for world oil (liquids) production).[16] Crude oil's share of total global liquids supply declines from around 78% in 2022 to 74% by 2050, given relatively greater growth of the other components (condensate and other NGLs as well as biofuels and other liquids). With respect to the geographic breakdown of global liquids supply, an important trend in our is robust growth of OPEC liquids output. OPEC production, in turn, becomes more concentrated in the fields of OPEC's Middle Eastern members (especially Saudi Arabia), while the chief non-OPEC producers during the period to 2050 are likely to remain the United States and Russia (even as these two countries' oil output contracts overall).

So called "shale" (or tight) oil production, currently concentrated in the United States, is also expected to continue to play a key role in world oil supply during the scenario period, while Kazakhstan may be poised to join the ranks of the world's "shale" oil producers in coming years (see text box "Prospects for shale (tight) oil development globally and in Kazakhstan").

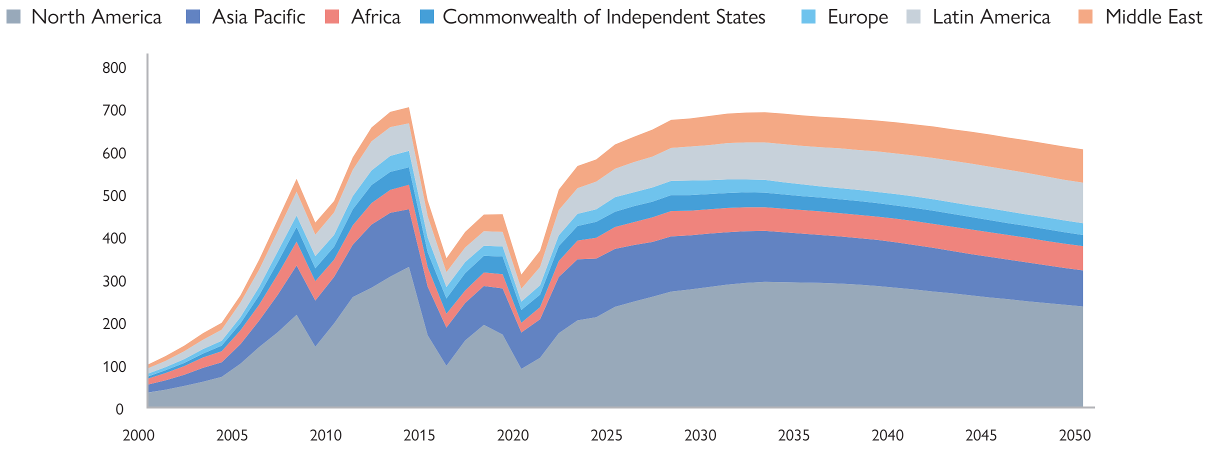
13 S&P Global Commodity Insights, Insight, *Global Conventional Exploration Trends: Fears of discovering tomorrow's stranded assets are overriding concerns on resource deficient portfolios — for now*, May 2023.

14 But Eurasia is an outlier among major world regions in our outlook; while all other regions register an increase in upstream E&P spending during 2023 in the base case, in Eurasia such expenditure is expected to decline by around 6%, to $33 billion.

15 For example, US shale exploration has evidently entered a new phase: although traditional exploration is also still occurring, companies appear to be focused more than before on development of under-exploited acreage within companies' existing license zones as opposed to targeting discoveries in new drilling acreage; see Energy Intelligence, *'Quiet' Exploration Takes Shape in US Shale Patch*, June 8, 2023.

16 The total liquids supply trajectory essentially mirrors the above-noted demand picture in our base case in volume terms; i.e., for modeling purposes, the outlook assumes zero total liquids inventory change—no stock builds or stock draws—on an annual basis (see Table 1.2).

Figure 1.8 Outlook for world upstream E&P spending (billion dollars, nominal)



Notes: Total spending for field development is determined using a bottom-up analysis of projects covered by our databases, while using actual project details provided by operating companies or major service contractors and then assuming construction period (normally three to four years), estimated spending is calculated; Mexico is not included in North America.
Source: S&P Global Commodity Insights.

Prospects for shale (tight) oil development globally and in Kazakhstan

Non-OPEC oil supply growth worldwide is dominated by US shale over the next five years in our outlook. Global tight oil production rises from around 8.4 million b/d in 2022 (of which the US share is around 94%) to a maximum of 11.7 million b/d in 2030 (when the US share is expected to amount to 91%), and then falls to 7.7 million b/d in 2050 (when the US share equates to 86%). Other shale oil producers during the scenario period (listed in order of the volume of their 2022 tight oil crude production) are Canada, Russia, Argentina, and mainland China.

In light of Kazakhstan's considerable shale oil potential (given the areal extent of its sedimentary basins), it would not be surprising if the country also eventually emerges as a significant shale oil producer, though much more exploration (and perhaps some actual commercial development) is needed before the scale of the commercially recoverable reserves is known. Key signposts of Kazakhstan's shale oil potential include a 2014 evaluation of the country's technically recoverable shale oil (and shale gas) resources by the US Energy Information Administration (EIA). The EIA assessment indicated shales and “other organic-rich source rocks” of Kazakhstan hold a risked and technically recoverable shale oil/condensate resource amounting 10.6 billion barrels, while the in-place risked and technically recoverable resource is 221 billion barrels.[17]

In the near term, the prospects for commercial development shale oil development in Kazakhstan hinge mainly on the efforts of the private South Oil company, which in February 2023 became the first in Kazakhstan to officially book shale oil reserves that it discovered in south-central Kazakhstan; specifically, in Karaganda and Kyzylorda oblasts (South Turgay Basin, where hydrocarbon accumulations are found at relatively shallow depths).

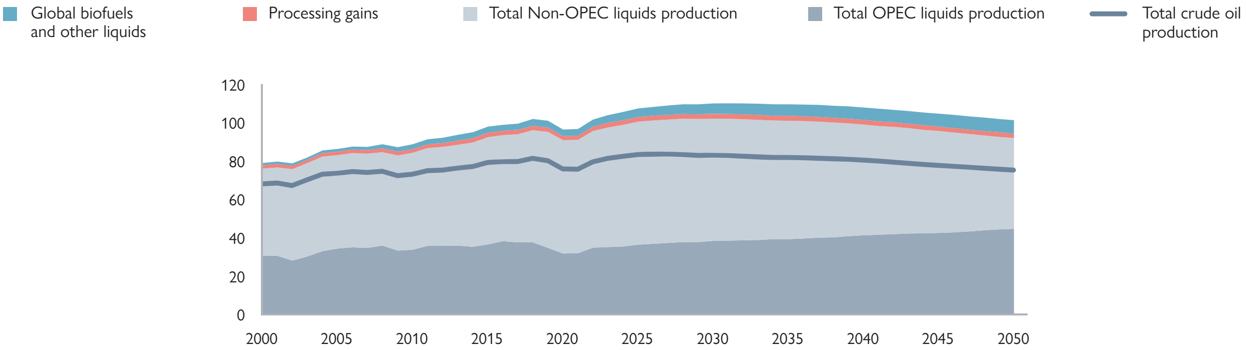
Since 2001, South Oil has owned the rights to subsoil use and exploration of hydrocarbons in contract areas No. 662 and 668, and since 2005 several fields have been discovered (Kenlyk, Aktau, Yeszhan, YuZ-Karabulak, Akshabulak Vostochny). In 2021, the company also partnered with colleagues from Russia, RN-BashNIPIneft LLC, on a study of deposits in the Lower-Middle Jurassic horizon of the South Turgay Basin. As part of the company's activities, an assessment was made of the resource potential of the Karagansay suite, confirming the oil and gas potential (specifically, well No. 40 in contract area No. 668 registered an oil flow rate of 0.5 m^3/day). Subsequently, on February 22, 2023, the State Commission on Mineral Reserves (under the Committee of Geology of the Ministry of Industry and Infrastructure Development) considered and approved the company's reserves report (“Calculation of shale oil reserves of the Karagansay block of unconventional hydrocarbon sources located in the Karaganda and Kyzylorda regions of the Republic of Kazakhstan”).

This, in turn, paves the way for more comprehensive study of the source rocks and subsequent commercial development. At the moment, South Oil is drawing up a work program in accordance with existing legislation, and the company reportedly plans to drill around 15 wells over the next 2-3 years, and 100-150 wells during the next 25 years. However, there are still many uncertainties surrounding the project, including the scale of the discovery, expected production volumes and ramp-up schedule, planned production technologies, development costs, financing arrangements, etc.

Development of shale oil in Kazakhstan may depend crucially on government support through more favorable above-ground “enablers” than are currently found in Kazakhstan; e.g., tax credits and supportive regulatory policies. Such measures underpinned the US tight oil production boom, for example. The EIA's study also cautioned that several key above-ground factors encouraging North American tight oil development might not apply elsewhere, including “private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable

17 U.S. Energy Information Administration, *Technically Recoverable Shale Oil and Shale Gas Resources: Kazakhstan*, September 2015, p. XXVIII-2, https://www.eia.gov/analysis/studies/worldshalegas/pdf/Kazakhstan_2014.pdf.

Figure 1.9 Outlook for world oil (liquids) production (million b/d)



Notes: The split of OPEC and non-OPEC countries is based on the member status as of July 2021; biofuels include US and Brazilian ethanol supply, and other liquids includes gas-to-liquids (GTL), coal-to-liquids (CTL), nonrenewable oxygenates, refinery additives, and oil shale (kerogen).
Source: S&P Global Commodity Insights.

drilling rigs…and the availability of water resources for use in hydraulic fracturing."[18]

More broadly, another key lesson of the US tight oil revolution for Kazakhstan is that conventional plays may also hold large-scale untapped tight oil reserves, which can, in turn, serve as a basis for redevelopment of many mature fields through much of the same technology (e.g., horizontal drilling in combination with multi-stage hydraulic fracturing). The possibilities for application of tight oil production technologies to mature fields nevertheless remain unexplored for the most part in Russia, where a shale oil development is most advanced within Eurasia. Russia's response to the North American tight oil phenomenon has consisted largely of an exploration of possible Russian analogs in new fields and plays instead of older conventional ones, with mixed results.[19]

Through 2030, the following supply-side factors are decisive in our base case outlook:

- Higher oil prices and a renewed focus on energy security are expected to continue to drive global upstream capex.
- S&P Global assumes the implicit oil project internal rate of rate (IRR) requirement has grown from 10% to 20%, reflecting investor pressure to boost returns and the growing risk that the energy transition creates for oil projects.
- The war in Ukraine has weakened Russia's oil sector in several key dimensions, and it is assumed that the country enters a long-term production decline during this period, with Western countries continuing to largely shun Russian export barrels; sanctions and higher taxes greatly complicate Russian upstream development going forward.
- The roadmap of near- to medium-term global oil supply depends heavily on US upstream development, which has a high potential to deliver incremental barrels through the 2020s. However, US crude production is expected to peak in the latter years of the decade.

Key drivers evolve during 2030-50 as follows:

- With a peak in global liquids demand in the early 2030s, lower upstream activity is needed to meet demand and offset natural field decline rates.
- As oil demand growth decelerates and the energy transition accelerates, investment shifts away from expensive, large-scale, single-project investments toward tight oil and smaller-scale projects that have faster payback periods.
- Small- or medium-scale onshore and subsea tieback projects, and those with multiphase expansion opportunities, are expected to account for most new-source conventional production over the outlook time horizon.
- The most expensive global areas for exploration face severe challenges. High-cost production in certain regions actually declines.
- By the 2030s we assume that Russia's relationship with the West improves, allowing more oil to flow to Europe, but the loss of foreign investment and access to international capital and technology is expected to prevent Russian production from recovering over the long term.

The wider OPEC+ group (Vienna Alliance) may account for the majority of world oil output during the latter part of the outlook period. This, in turn, indicates the potential for strong continued or even increased OPEC+ influence in global oil markets. But key wildcards include the future evolution of the group's membership (see Table 1.3 OPEC+ voluntary production quotas, as of July 2023). At the same time, the Eurasian members of the Vienna Alliance (Russia, Kazakhstan, and Azerbaijan) are each expected to register a decline in oil output during outlook period, suggesting that net production by non-OPEC members of the Vienna Alliance may fall overall even as the OPEC members of OPEC+ increase their output (the Eurasian share of crude oil production among non-OPEC members of the alliance recently amounted to over 85%). In the base case, total OPEC liquids

18 Ibid., p. 3.

19 For a comparison of the initial periods of tight oil development in the United States and Russia, see the S&P Global Private Report, *Tight Oil in Russia: Can development spur a West Siberian renaissance?*, July 2012. Starting in 2014, Western sanctions effectively derailed a number of promising shale oil joint ventures between Russian companies and IOCs, but this is only part of the explanation for why Russia's immense tight oil potential (e.g., the Bazhenov Formation underlying much of the West Siberian Basin) remains mostly unrealized. The absence inRussia of the aforementioned above-ground ingredients for a tight oil revolution is perhaps an even greater constraint.

Table 1.3 OPEC+ voluntary production quotas, as of July 2023 (million b/d)

OPEC	Quota	Non-OPEC	Quota
Algeria	0.96	Azerbaija	0.68
Angola	1.46	Bahrain	0.20
Congo	0.31	Brunei	0.10
Equatorial Guinea	0.12	Kazakhstan	1.55
Gabon	0.17	Malaysia	0.57
Iraq	4.22	Oman	0.80
Kuwait	2.55	Russia	10.48
Nigeria	1.74	Sudan	0.07
Saudi Arabia	8.98	South Sudan	0.12
UAE	2.88	**Total Non-OPEC**	**14.57**
Total OPEC	**23.38**	**Total OPEC+**	**37.95**

Source: S&P Global Commodity Insights.

production grows from 34.5 million b/d in 2022 to around 44 million b/d in 2050 for an increase of 28%, while OPEC's share of global liquids output during the same period increases from around 34% to 44%. In contrast, the oil production by the Eurasian members of OPEC+ is expected to fall from 13.2 million b/d in 2022 to roughly 10 million b/d in 2050, declining by 24% altogether, while the Eurasian share of global output drops from 13% to 10%.[20]

The three largest oil producers globally during the period out to 2050 remain the United States along with OPEC+ members Saudi Arabia and Russia. These three producers accounted between them for over 30% of global liquids supply in 2022. But quite different dynamics are envisioned for each going forward:

- ***US oil production is projected to peak by the early 2030s and then decline during the remainder of the outlook period.*** Despite the general cooling oil price environment, we still expect prices will remain robust enough for oil companies to grow production while continuing to generate hefty volumes of free cash flow that will flow back to investors. In the base case, US average annual oil output rises from 11.9 million b/d in 2022 to a peak of about 15.1 million b/d in 2032—roughly 3 million b/d above the previous maximum achieved in 2019. But core inventory exhaustion creates an increasing drag on output by the early 2030s, resulting in declining output for the rest of the forecast horizon, to around 11 million b/d in 2050.
- ***Saudi Arabia produced at its highest sustained rate in history in 2022 and remains on a growth trajectory in our outlook.*** Saudi crude oil output (accounting for the vast majority of its total liquids production) amounted to 10.6 million b/d in 2022, and is expected to average well over 10 million b/d for the rest of the decade, compensating for declining output in other OPEC+ countries. In our long-term outlook, Saudi Arabia's ability to sustainably increase output increases sharply beyond 2030, despite the peaking of global crude demand. By the following decade, non-OPEC (and some OPEC) supply will be in decline, requiring increases in Saudi output to meet the overall world call on crude. Redevelopments and enhanced oil recovery projects will drive new source growth in the country, and by 2050 national crude oil output is expected to amount to around 13 million b/d.
- ***Russia's war in Ukraine has set its upstream on a path of long-term decline.*** Russia's crude oil and condensate output rose slightly to 10.7 million b/d in 2022. We expect Russian oil production to decline during subsequent years of the outlook period. Our forecast envisions fewer new projects proceeding than in our previous outlooks. As a result, Russia's aggregate output is not able to offset ongoing (and inevitable) declines in older fields even through 2030 as anticipated previously. Russian production is expected to decline by about 500,000 b/d from 2025 through 2030 and plateau in 2030–35 at about 8.5 million b/d as new projects offset most of the declines from older producing fields. Decline rates in the short term are thawed by the ongoing robust expansion of condensate supply, but national liquids output dwindles to only around 8 million b/d by 2050 in the base case.

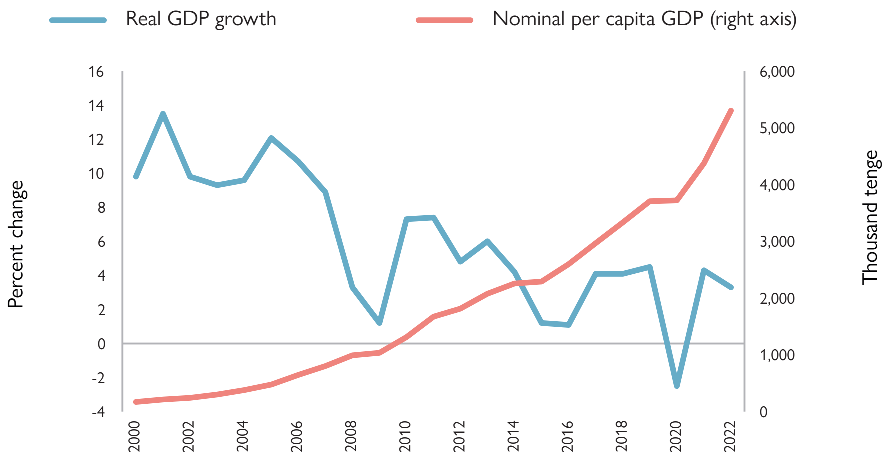
1.4.3 Implications for Kazakhstan

These world oil price and supply-demand dynamics are taken as a general indicator of many global commodities, with key implications for the economies of major commodity exporters such as Kazakhstan. For example, there is likely to a high, sustained global demand for the many critical minerals of the energy transition, such as copper, lithium, cobalt, and manganese, while demand for others, such as coal, declines.

But throughout the period of Kazakhstan's independence, hydrocarbon resources have been an important factor and contributor to Kazakhstan's economy. Revenues from hydrocarbon exports (crude oil, condensate, refined products, natural gas) have increased manyfold since 2000 and account for well over half of the country's total export earnings (e.g., $50.7 billion out of $84.4 billion, or 60.0% in 2022), as well as a large percentage of total budget revenues and foreign direct investment. Overall, the development of the national oil and gas industry has served Kazakhstan well, generating vital revenues and bringing in new

20 The corresponding numbers for the individual Eurasian members of OPEC+ in our base case are as follows: Russian oil production falls from around 10.7 to 7.9 million b/d (-26%); Kazakh output drops from 1.8 to 1.5 million b/d (-15%); Azeri volumes decrease from 0.7 to 0.6 million b/d (-17%).

Figure 1.10 Kazakhstan's real annual GDP growth, 2000-22



Notes: Preliminary estimate of 2022 nominal per capita GDP.
Source: S&P Global Market Intelligence.

technologies and activities that have solidified the country's economic independence and delivered higher living standards. The extraction of hydrocarbon resources will remain an important element of Kazakhstan's economy for the foreseeable future, as the country will remain a significant global oil producer. But the heightened role of the hydrocarbon sector in Kazakhstan since the turn of the century also spells increased sensitivity of national macroeconomic dynamics to global oil markets and prices—which can make the difference between government budget surpluses or deficits, and the profitability or not of upstream investment.

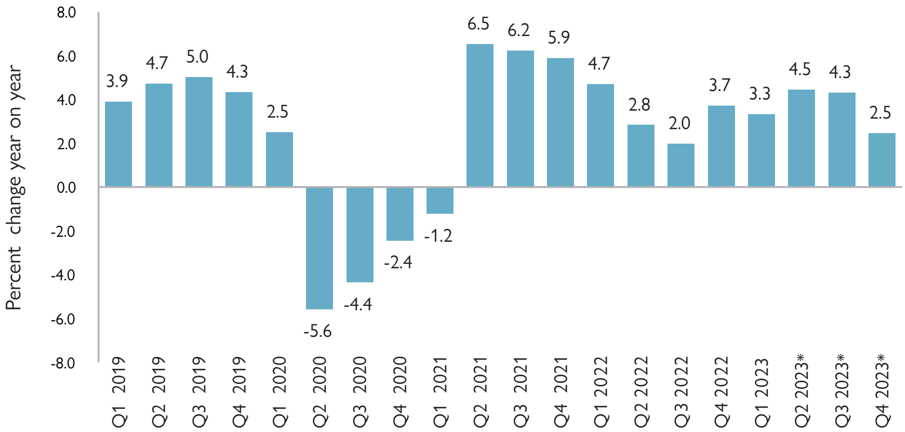
1.4.3.1 Kazakhstan's economy: Oil price changes played key role in 2020-23 "roller coaster" ride

Kazakh GDP trends during 2020-23 illustrate the positive contribution of world oil price trends to Kazakhstan's economic performance as well as the downside risks (see Figure 1.10 Kazakhstan's real annual GDP growth, 2000-22, and Figure 1.11 Kazakhstan's quarterly GDP change, 2019-23):

- ***2020-21: GDP contraction and then rebound with declining and then rising world oil prices.*** In 2020, GDP fell by 2.5% (the deepest recession for Kazakhstan in two decades) as a result of depressed external demand and lower prices for Kazakhstan's hydrocarbon exports owing to the COVID-19 pandemic. These effects were compounded by the negative impact of lockdowns on domestic economic activity. But in 2021 Kazakhstan's economy recovered. A rebound in oil prices and rising external and domestic demand due to improvement in the epidemiological situation were accompanied by a rapid acceleration of Kazakhstan's quarterly GDP growth: from -1.2% in Q1 2021 to 6.5% in Q2, followed by a rise of 6.2% in Q3 and 5.9% in Q4. GDP increased by 4.3% overall in 2021, restoring pre-pandemic levels of economic activity.
- ***2022-23: GDP growth continued, but at a slower rate, reflecting the new geopolitical headwinds as well as less oil price growth in 2022 and price decline in 2023.*** The onset of the Russia-Ukraine war in February 2022, and ensuing Western sanctions on Russia (and Belarus, both of which like Kazakhstan are members of the Eurasian Economic Union) initially cast a pall over Kazakhstan's economic recovery, notwithstanding the positive oil price dynamic during much of 2022: Q1 GDP growth in 2022 already had begun to cool from the previous quarter, to 4.7%, and slowed further in Q2 to 2.8%, while the results for Q3 and Q4 were 2.0% and 3.7% growth, respectively, resulting in an annual 2022 GDP rise of 3.3%—somewhat lower than previous, pre-war forecasts in the 3.9%–4.0% range. S&P Global projects 2023 Kazakh GDP growth at around 3.7%, although first half growth was about 5%.[21]

21 In addition to the impacts of the war and sanctions on nearby states and major trading partners, civil unrest in Kazakhstan in early January 2022, sparked by public dissatisfaction with higher fuel prices, led to the declaration of martial law and the dispatch of Russian peacekeepers under the auspices of the Collective Security Treaty Organization to quell looting and episodic violence in Almaty, Astana, and other urban centers. The overall security situation then stabilized, while policy directions announced by President Kassym-Zhomart Tokayev in the aftermath of the unrest had the effect of slowing the pace of energy price hikes. For background, see S&P Global Commodity Insights, Insight, *Kazakhstan's President Outlines New Directions and Reforms in Aftermath of Mass Demonstrations: What does it mean for the energy sector?* January 2022.

Figure 1.11 Kazakhstan's quarterly GDP change, 2019-23



Notes: *Preliminary estimate or outlook.
Source: S&P Global Market Intelligence.

The above-noted general trends also mask a diversity of outcomes across the different sectors of the economy, as the repercussions of oil and other global commodity price swings as well as sanctions and disrupted trade patterns are felt unevenly. The following key Kazakh supply- and demand-side trends underlie GDP dynamics:

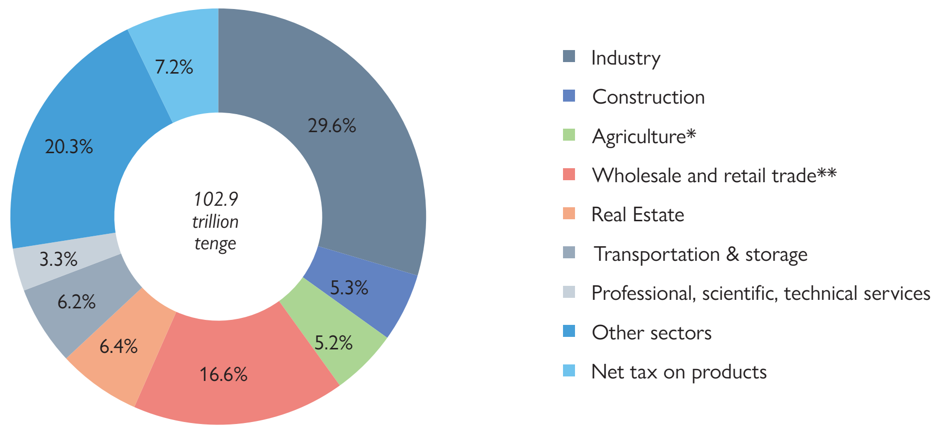
- ***Supply side: energy sector recovery continues to lift the national economy.*** The single largest component of the economy, comprising 29.6% of 2022 GDP, is the export-oriented industrial sector, which encompasses the mining and quarrying (extractive) sector of the economy including energy (see Figure 1.12 Kazakhstan's GDP in 2022 by sector). Industrial output jumped by 22.5% in 2022 in tenge terms, and this represented the sharpest increase of any major segment aside from agriculture (+25.9%). The energy sector remains a primary driver of the Kazakh economy, considering both shares in total industrial production and GDP overall, while oil accounts for the bulk of Kazakh export earnings and is the main source of the government's budgetary revenue. The oil and gas industries alone, together with related sectors (e.g., oil and gas transportation, upstream construction, and geology) probably contributed about 20% of the country's GDP directly in 2022, compared with 19.4% in 2021 (see Figure 1.13 Kazakhstan's oil and gas industry contribution to GDP). Meanwhile, combined revenue from crude oil and refined product exports jumped by 51.1% in 2022 to $48.4 billion—surpassing the 2019 level even though physical export volumes still remained somewhat lower (see Figure 1.14 Kazakhstan's oil export volumes and revenues). Such heavy reliance of the national economy on the hydrocarbon sector means that global trends, such as commodity price fluctuations, had a broad effect in Kazakhstan, both directly and indirectly, impacting the performance of other sectors, including transportation, construction, retail trade, and professional services. [22]

- ***Demand side: the energy sector has lagged various other sectors in the post-2020 rebound for investment in fixed capital, indicative of relatively weak returns.*** Following the 2020 drop, total investment 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—recovered by 2022 to nearly the 2019 level or surpassed this level depending on the type of measurement (see Figure 1.15 Kazakh energy sector fixed asset investment by segment in current dollars and Figure 1.16 Kazakh energy sector fixed asset investment by segment in constant (2010) tenge). In current dollar terms, for example, total investment in fixed assets rose by 13.4% in 2021 and by another 6.4% in 2022, to a total of $29.7 billion last year—only 1.6% lower than 2019. The growth spurt has been even greater measured in constant (2010) tenge terms; although such tenge-denominated investment declined by 4.1% in 2021, a 2022 surge of 33.6% more than erased the 2020-21 drop, and left this investment 9.9% higher than in 2019. Not surprisingly, the share of the energy sector in fixed capital investment has been on the rise since 2020, when this share collapsed from 52.7% to 32.4%, but in 2022 the energy sector's share had only recovered to 34.0%. The post-2020 investment boom has occurred mainly outside of the energy sector; aggregate investment in fixed assets in non-energy sectors actually remained on a growth trajectory in 2020, and by 2022 was already 37.1% higher than in 2019 in current dollar terms (53.2% higher in constant 2010 tenge). In contrast, energy sector fixed capital investment collapsed by over 49.8% in 2020 in current dollar terms (by 47.1% in constant 2010 tenge), and in 2022 was still 36.4% below the 2019 level in current dollars (29.0% lower in constant 2010 tenge), though such investment is now well above the 2020 level.[23]

22 The distinction between the energy-specific segments of the economy and other sectors is not always clear-cut. Much service sector activity, for example, is closely interrelated with energy industry dynamics, as mobility (transportation) is normally entailed in accessing goods and services.

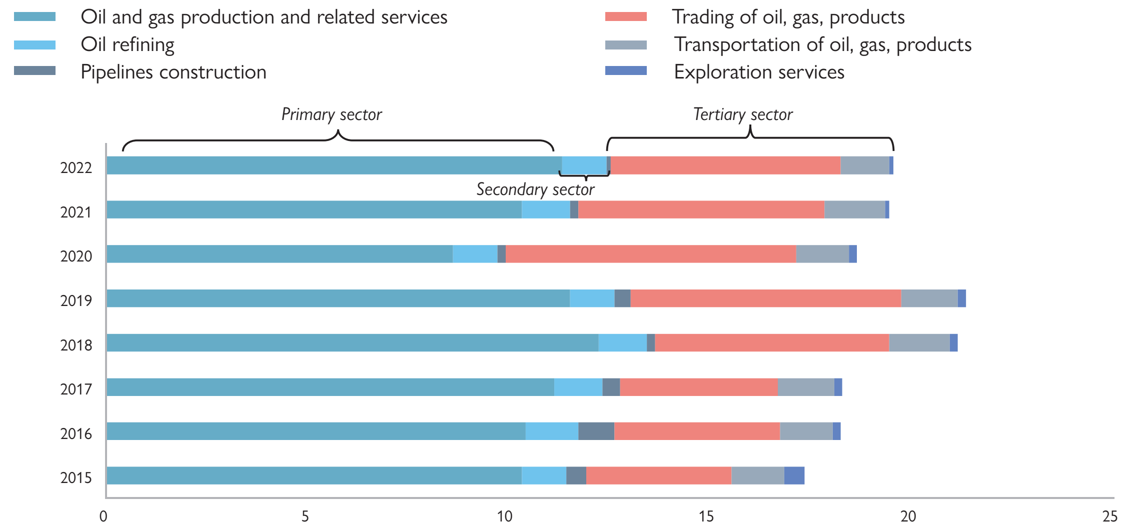
23 Private consumption in Kazakhstan, the single largest segment of domestic demand, rose by 8.4% in dollar terms in 2022, to $110.4 billion.

Figure 1.12 Kazakhstan's GDP in 2022 by sector (% of total)



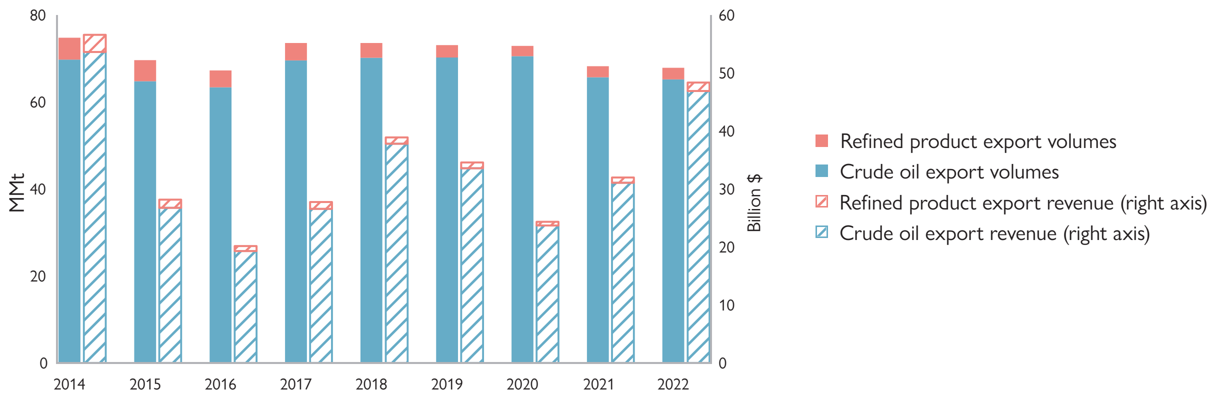
Notes: *Includes forestry and fishing; **Includes repair of automobiles and motorcycles.
Source: S&P Global, Bureau of National Statistics RK.

Figure 1.13 Kazakhstan's oil and gas industry contribution to GDP (% of GDP)



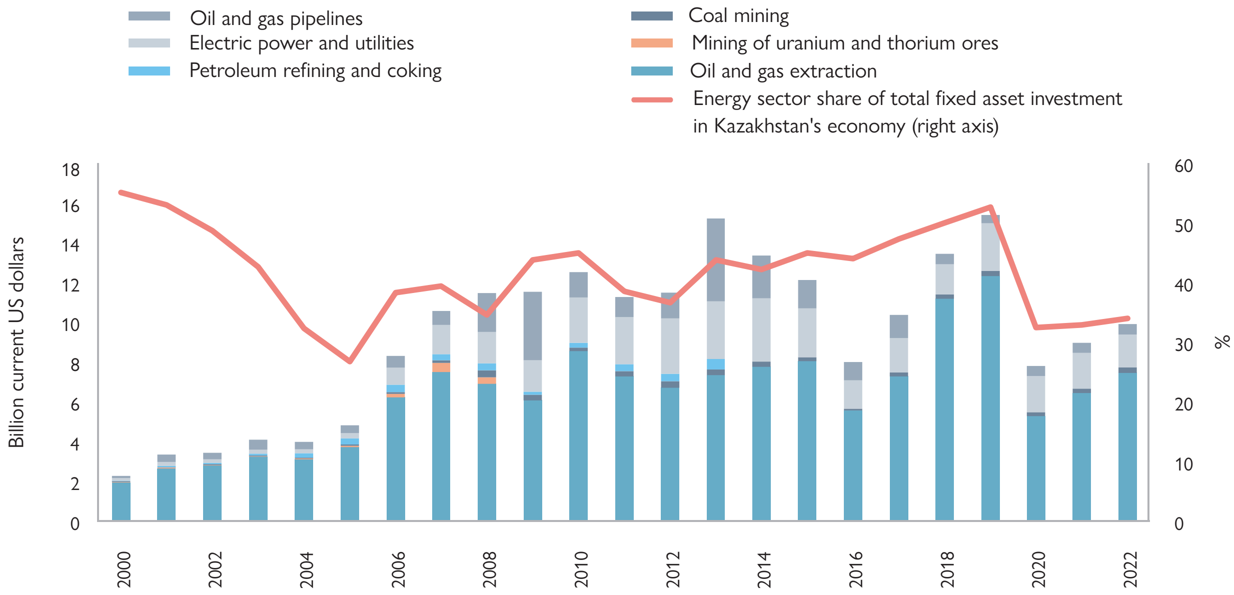
Source: S&P Global Commodity Insights, Bureau of National Statistics RK.

Figure 1.14 Kazakhstan's oil export volumes and revenues (2014-22)



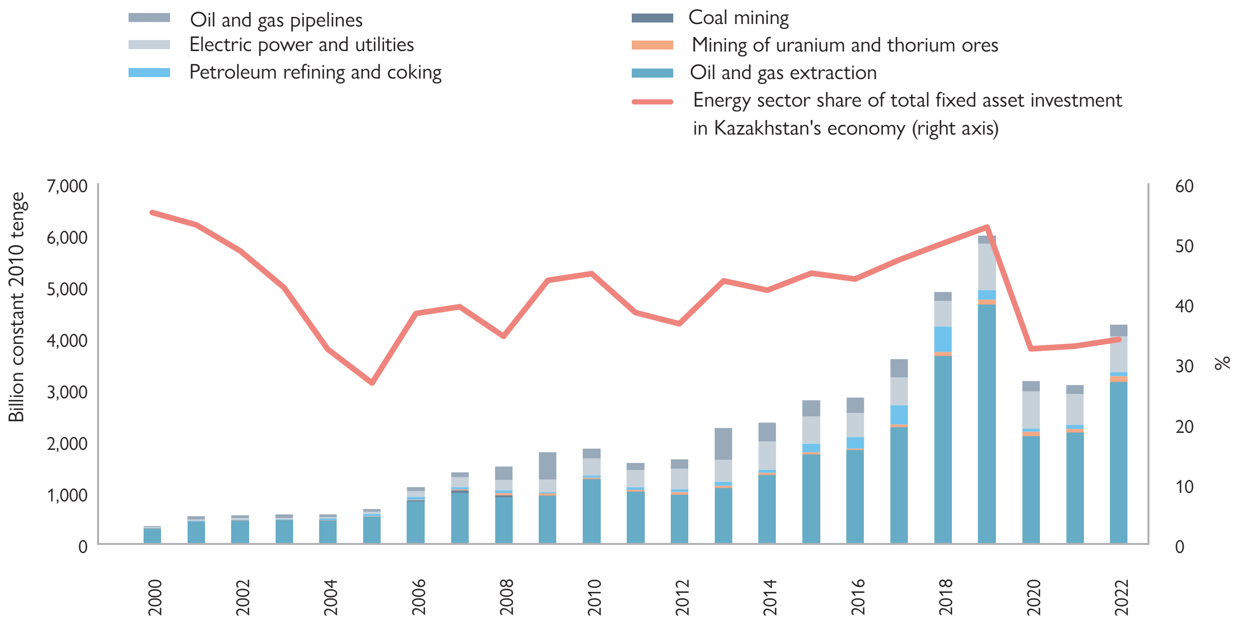
Source: S&P Global Commodity Insights, Bureau of National Statistics RK (for export revenue).

Figure 1.15 Kazakh energy sector fixed asset investment by segment in current dollars



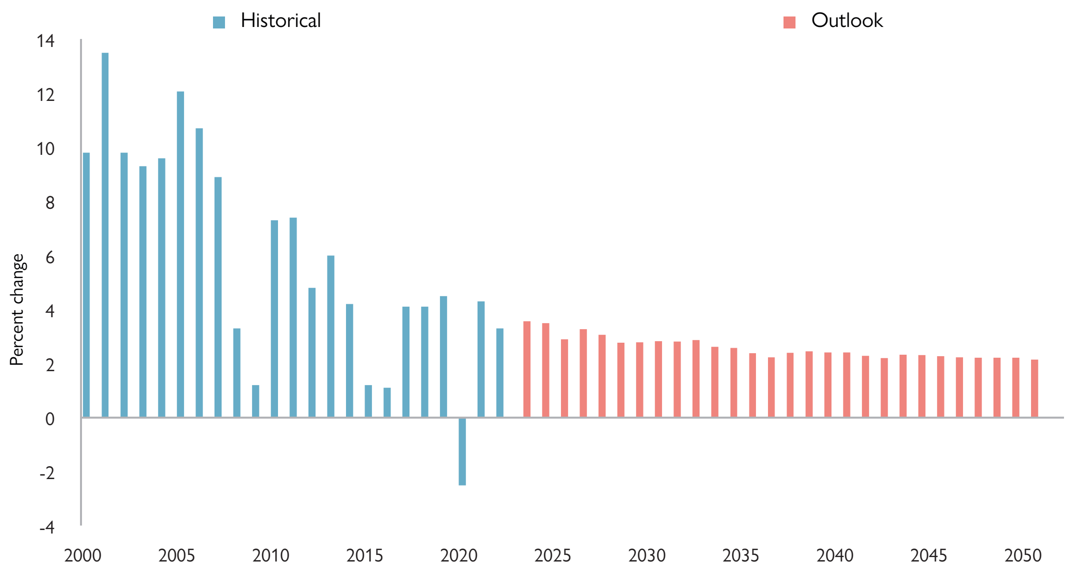
Source: S&P Global Commodity Insights, Bureau of National Statistics RK.

Figure 1.16 Kazakh energy sector fixed asset investment by segment in constant (2010) tenge



Source: S&P Global Commodity Insights, Bureau of National Statistics RK.

Figure 1.17 Kazakhstan's GDP growth rate: historical and outlook to 2050



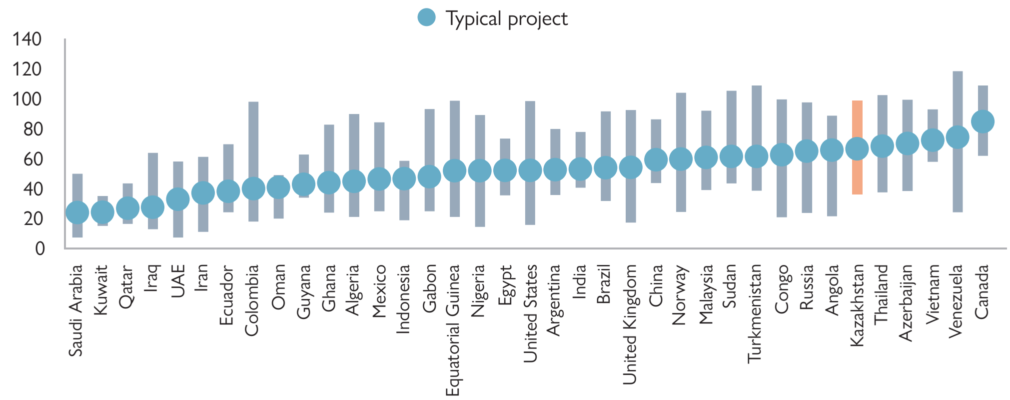
Source: S&P Global Market Intelligence, S&P Global Commodity Insights.

The downward impact on exports and repercussions on the broader Eurasian region from Western sanctions may also dampen growth rates going forward, although the overall situation remains in flux, and therefore forecasts come with a greater amount of uncertainty. To sum up our outlook for Kazakhstan's national economy's longer-term growth prospects, the base case is for real GDP to expand at a good pace, although slowing over time; this is at an annual rate averaging 2.6% during 2023-50. Deceleration is partly a natural consequence of the economy becoming larger over time: after averaging 3.1% during 2023-30 in the outlook, annual GDP growth slows to an average of 2.5% over 2031-40, and then 2.2% during 2041-50 (see Figure1.17 Kazakhstan's GDP growth rate: historical and outlook to 2050)

1.4.3.2 Kazakhstan's upstream development: Cost trends heighten urgency of policy reforms to attract new investment

S&P Global's comparative analysis of upstream costs in oil-producing countries, for typical projects that will be launched over the next few years, indicates that Kazakhstan (and other Eurasian producers) may struggle to remain competitive with their international counterparts and retain (let alone grow) their global market share. Our latest comparison of full-cycle upstream project costs, for 2022, indicates that Eurasia had the highest regional average of typical project break-even costs at $66.35/bbl. The S&P Global cost curve methodology calculates a break-even price for a typical new Kazakhstan project in 2022 at about $67/bbl, although there is a considerable range around this central point; i.e., from a low of $36/bbl to a high of $99/bbl. This midpoint for Kazakhstan generally places the country on the right-hand side (higher-cost end) of the global cost curve, and the high variability indicates that a sizable proportion of Kazakhstan's potential incremental production is exceptionally costly (see Figure 1.18 Full-cycle costs in terms of Dated Brent for selected oil-producing countries in 2022, and box "The S&P Global full-cycle cost calculation methodology for 'new' oil production"). Longer term, the outlook is for Kazakh oil to remain relatively high cost in comparative international terms; in 2040, for example, new Kazakh oil projects yielding oil that year are expected to break even at around $70/bbl (in 2022 dollars), whereas about 65% of the 30 million b/d of new global crude production by 2040 from areas covered in the forecast breaks even at $50/bbl or less.

Figure 1.18 Full-cycle costs in terms of Dated Brent for selected oil-producing countries in 2022 ($/bbl)



Notes: UAE = United Arab Emirates; assumes a 20% rate of return.
Source: S&P Global Commodity Insights.

The S&P Global full-cycle cost calculation methodology for "new" oil production

The S&P Global full-cycle cost calculation captures costs at the wellhead, including opex, capex, and upstream taxation; i.e., the cost of finding, developing, and then producing "new" oil production capacity. Our proprietary methodology shows these as "break-even" costs at the country level in aggregate, but actually involves analysis of individual upstream development projects within each country's portfolio; hence, they are shown as a range. This is essentially a forward-looking analysis, to understand the cost of developing new supply and allows us to highlight areas where new project development is viable at current (or expected) oil prices. Reservoir data and production profiles are estimated, and drawn from the S&P Global database, and the terms are adjusted by project, based on known information. The average (per country and/or geographical area) shown is not a weighted or arithmetic average but a selection of what a typical new oil project in that country or area (onshore/offshore) would cost in current conditions.

More specifically, the fields selected for analysis represent the typical projects that will begin development over the next few years, and the cost calculation covers full-cycle break-even costs including exploration, extraction, operation, government take, and final decommissioning. An estimate was prepared for each field and the risk premium calculated by market. The risk premium was calculated by incorporating all the risk factors—including political, economic, legal, tax, operational, and security risks—that could affect each project. The methodology to calculate break-even costs is provided through the following steps:

- Determine the cost of exploration, including appraisal wells.
- Add the cost of development, including any relevant risk premiums.
- Add the cost of operations.
- Apply a fiscal model to determine the oil price required for an acceptable internal rate of return (IRR) and highlight areas where project development is viable at current oil prices.
- Leverage the S&P Global Commodity Insights Vantage tool to extract production and cost projections to determine projects for analysis in each market.

To facilitate an equivalent comparison between regions, S&P Global Commodity Insights generated the oil price required for a 20% IRR for each of the projects. This is the "break-even price" for the relevant market. The price differential between the typical crude production from that market and the Brent oil price is added to this break-even price. The data was run using the S&P Global Commodity Insights QUE$TOR software, as well as the Energy and Climate Scenarios second-half 2022 data set.

At the same time, there are some limitations of the break-even cost analysis impeding a country-by-country comparison of all potential cost components; e.g., the break-even numbers do not calculate fiscal breakeven (cost per barrel necessary to provide all government services). They also do not include transportation to market or export duties.[24]

24 For additional detail, see S&P Global Commodity Insights, Strategic Report, *Cost of Oil Report: 2022*, April 2023.

Perceptions of above-ground risk factors in host countries also factor heavily into the E&P investment decisions of international players, and more enlightened policies by Kazakh state authorities could go far to enhance the country's ability to compete for the limited global capital available to finance upstream activity going forward. Kazakhstan has typically underperformed vis-à-vis most other oil-producing countries selected for analysis in a quarterly rating of E&P attractiveness that was developed by the S&P Global Petroleum Economics and Policy Solutions (PEPS) team.

Kazakhstan's overall score in the PEPS ranking is comprised of a blend of scores representing legal and contractual terms, fiscal systems, and overall oil and gas risk. Since *The National Energy Report 2021*—specifically, starting in January 2023—our E&P attractiveness ratings default weights have been changed to an "Above-Ground Focus" weight profile in order to better reflect the PEPS service's focus on above-ground factors that affect a country's E&P investment environment—while we continue to provide ratings based on the legacy weights that consider a broader range of variables. Over time Kazakhstan has improved its standing in terms of both the rating that focuses on above-ground factors and the rating based on legacy weights, but the country's score nevertheless remains relatively low compared with that of other leading (or comparator) oil-producing countries.[25] This can be seen, for example, from a review of changes in Kazakhstan's rating each year during the same quarter of the last ten years, insofar as the PEPS scores are relatively comparable from year to year over 2014-23. For example, with respect to the above-ground focused ratings during the third quarter of each year, during this ten-year period Kazakhstan's rating on a scale of 1 to 10 (with 10 being most attractive) improved from 4.91 to 5.39, while its rank among around 110 oil-producing countries selected for analysis (with 1 being most attractive) improved from 89 to 78 (see Table 1.4 Evolution of Kazakhstan's E&P Attractiveness rating and rank, 2014-23; Figure 1.19 S&P Global's E&P attractiveness ratings of selected oil-producing countries for Q3 2023: Above-Ground Focus weight profile).

Kazakhstan's ranking among countries in a general peer group cannot be readily compared over such an extended period of time since the S&P Global analysis has shifted the composition of this group markedly over the years. S&P Global currently ranks Kazakhstan at 7th place out of 8 nations in what is called the "petrostate" peer group (see Figure 1.20 Kazakhstan peer group E&P attractiveness ratings for Q3 2023: Above-Ground Focus weight profile). S&P Global defines petrostates as countries where the production of oil and gas is a major source of economic activity, fiscal revenues, and exports; critically, exports of oil and gas by such nations have exceeded 20% of total exports over the last five years.[26]

Kazakhstan continues to suffer largely from a low fiscal component in the overall rating; its fiscal ratings score reflects relatively poor results in the categories of profit/investment ratio, state and government take, and investor cash flow (for additional background on the S&P Global fiscal systems ratings and other methodological issues, see the text box "The S&P Global E&P attractiveness ratings methodology"). Specifically, in the third quarter of 2023 Kazakhstan ranked only 95th in terms of fiscal systems rating among the same 112 oil-producing countries selected for the overall E&P attractiveness ranking. As discussed in Chapter 5 in more detail, potential policy shifts that could significantly improve Kazakhstan's E&P attractiveness rating include additional fiscal incentives for harder-to-recover oil, greater flexibility in terms of domestic content requirements, and further Kazakh oil market price reforms needed to ensure that domestic deliveries of crude oil and refined products are as profitable as exports.

25 It should be noted that the periodic refinement of the PEPS methodology for E&P attractiveness ratings and rankings complicates analysis of the evolution of any country's score over an extended period of time; e.g., changes in the number of indicators taken into consideration, and changes in a country's designated peer group. With this caveat in mind, it is nevertheless instructive to review Kazakhstan's progress during the period 2014-23, when the key indicators selected for analysis are relatively consistent over the years compared with earlier periods.

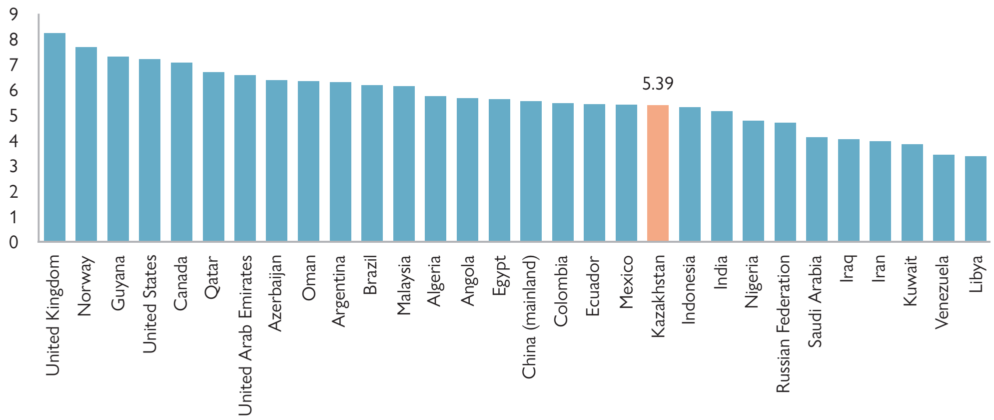
26 For more detailed comparative analysis of dynamics within this and other peer groups, see S&P Global Commodity Insights, Strategic Report, *Oil & Gas Risk Quarterly: In the Balance—Pressures on E&P Terms,* May 2023.

Table 1.4 Evolution of Kazakhstan's E&P Attractiveness rating and rank, 2014-23

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Overall attractiveness rating	4.91	4.86	4.83	5.08	4.91	4.79	4.51	4.77	5.36	5.39
Rank among all oil-producing countries selected for comparison	89	89	91	84	80	80	88	82	79	78

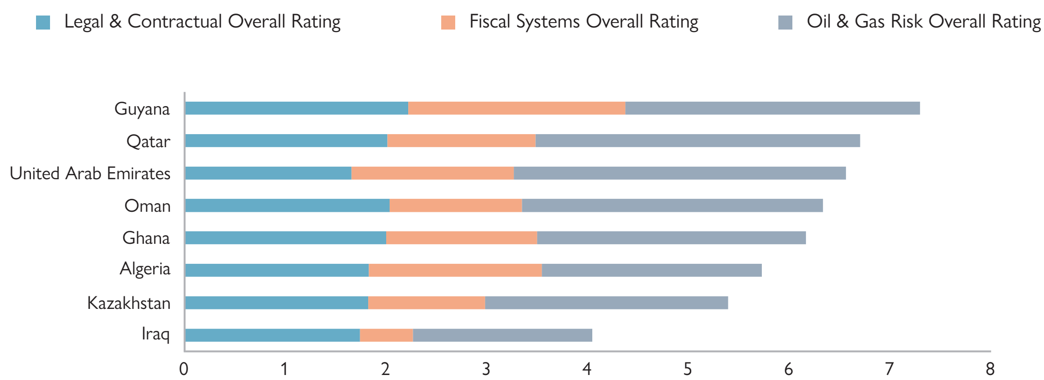
Notes: Ratings and rankings for the third quarter of each year. The overall E&P attractiveness (Above-Ground Focus weight profile) score is based on a weighting of the key sub-components of the rating as follows: Legal and Contractual (30%), Fiscal Systems (30%), Oil & Gas Risk (40%).
Source: S&P Global (PEPS).

Figure 1.19 S&P Global's E&P attractiveness ratings of selected oil-producing countries for Q3 2023: Above-Ground Focus weight profile



Notes: Ranking as of third quarter 2023 for 30 largest crude oil producers in 2022. The overall E&P attractiveness (Above-Ground Focus weight profile) score is based on a weighting of the key sub-components of the rating as follows: Legal and Contractual (30%), Fiscal Systems (30%), Oil & Gas Risk (40%).
Source: S&P Global (PEPS).

Figure 1.20 Kazakhstan peer group E&P attractiveness ratings for Q3 2023: Above-Ground Focus weight profile



Notes: The overall E&P attractiveness (Above-Ground Focus weight profile) score is based on a weighting of the key sub-components of the rating as follows: Legal and Contractual (30%), Fiscal Systems (30%), Oil & Gas Risk(40%).
Source: S&P Global (PEPS).

The S&P Global E&P attractiveness ratings methodology

The E&P Attractiveness Ratings (EPAR) rank a country by overall exploration and production (E&P) attractiveness for petroleum investment. EPAR is composed of 60+ variables relating to three core above-ground elements that affect the value of upstream investments.

1. The Legal and Contractual Terms Attractiveness component of the EPAR includes the following six categories:

- Regulatory and Institutional Framework
- Terms for Entering / Acquisition of E&P Rights
- Contractual and Licensing Framework
- Commercial and Operational Requirements
- Contract Variations and Exit Terms
- Key Environmental Provisions

2. The Fiscal Attractiveness component of the EPAR includes the following eight categories:

- Undiscounted State Take[27]
- Undiscounted Government Take[28]
- Investor Cash Flow (US$/bbl)
- Investor Cash Flow (US$ million)
- Investor Internal Rate of Return (IRR, %)
- Investor Net Present Value (NPV) @ 12.5% (US$/bbl)
- Investor NPV @ 12.5% (US$ million)
- Investor Profit/Investment (P/I) Ratio

3. The Oil and Gas Risk component of the EPAR includes the following categories:

- Politics, with sub-categories of State Capacity, Political Legitimacy, Political Violence, Geopolitical Risk
- Economics, with sub-categories of Non-Payment Risk, Primary Fiscal Balance, Real Per Capita GDP Growth, Level of Development
- Hydrocarbon Sector Entry, with sub-categories of International Openness, Government Take, Expeditiousness of Contract, State/NOC Role
- Hydrocarbon Sector Operations, with sub-categories of Sanctity of Contract, Regulatory Burden, Civil Society Risk, Corruption, Rule of Law
- Hydrocarbon Sector Shocks, with sub-categories of Market Access, Facility and Personnel Violence, Ministerial/Policy Volatility, Labor Unrest

Each variable is assigned a rating ranging from 1 to 10 (where 1 represents the least attractive and 10 the most attractive from the investor's perspective). The scores for each variable are then weighted to calculate the overall E&P attractiveness score for each country. While the model encompasses some aspects that can be quantified, many of the risk scores accorded to the countries covered in the model are based on qualitative judgements.[29]

1.5 High-Level Takeaways

S&P Global draws the following key conclusions and implications for Kazakhstan from the research presented above:

- ***World oil prices: The higher average long-term world oil price now expected, compared with our previous outlook, underscores the criticality of Kazakh and other oil supplies to meet global demand throughout the outlook period, though the main beneficiaries are probably lower-cost producers.*** Oil producers in Kazakhstan (as elsewhere) are subject to much the same set of key factors underlying the ratcheting up of the price outlook since 2021 in our long-term base case, and some of these factors may be even more acute in Kazakhstan's case compared with that of most other oil-producing nations; e.g., Kazakhstan may be exceptionally vulnerable to the new inflationary pressures related to supply chain issues, given the extra logistical challenges associated with the country's landlocked status and distance from major international oilfield equipment and service supply centers. The higher price assumed in our current base tends to increase the longevity of already-producing Kazakh fields, but most of the prospective new upstream projects in Kazakhstan may well remain "out of the money," and Kazakhstan is likely to lose export market share in the longer term to lower-cost producers, concentrated largely in the Middle East.
- ***Global oil market structure: The strong partitioning of the global market due to Western sanctions may open up some new niches in Russia's former European markets for Kazakhstan (as well as other producers), but this upside is largely offset by the intensified competition from Russian barrels in the more dynamic "East of Suez" markets, and new sanctions-related downside risks for third parties.*** Although Western sanctions have severely constricted Russia's oil export options, these measures are not an unqualified boon for Russia's competitors. European oil demand had already entered a long-term decline trajectory well before 2022 and the dramatic escalation of the armed conflict in Ukraine, while the Asia Pacific markets to which Russia has redirected the bulk of its exports following

27 State Take is the percentage of the Gross Project operating profit that accrues to the Government by way of royalties, production sharing (where applicable) and taxes paid by the investor(s), plus the operating profit attributable to the state's direct participation in a project; e.g., in the form of an NOC.

28 Government Take is the percentage of the Gross Project operating profit that accrues to the Government by way of royalties, production sharing (where applicable) and taxes paid by the investor(s). Government Take is similar to State Take but it excludes any cash flow attributable to the direct financial participation in a project by the state or NOC.

29 For additional detail, see S&P Global Commodity Insights, Methodology, *EPTAGR E&P Attractiveness Ratings Methodology,* August 2023.

sanctions are among the chief centers of global oil consumption growth (longer term, as sanctions impinge on production levels, Russia will be hard-pressed to sustain exports to these markets at current levels). Kazakhstan has so far effectively neutralized much (if not all) of the negative knock-on effects from the war in Ukraine on its oil exports; e.g., by KEBCO rebranding. But Western sanctions will continue to pose risks for Kazakh oil industry players during much (if not all) of the outlook period along different segments of the value chain—limiting the scope for partnerships with Russian companies and heightening risks associated with transit of exports via Russian territory.

- ***Supply fundamentals: OPEC+ continues to play a key market balancing role, but the opportunity costs associated with increased cuts may grow for Kazakhstan in the near as well as longer term.*** As a member of the sub-group of OPEC+ member nations committing in the first half of 2023 to additional output cuts, through the end of 2024, Kazakhstan has carved out a more significant role for itself within the Vienna Alliance. But Kazakhstan's ability to execute on promised cuts is likely to become even more challenging than before, with the onset of the Tengiz project expansion now expected by the end of 2024—potentially leaving Kazakh policymakers with the difficult choice of falling short in terms of compliance with planned production cuts, or sacrificing national growth opportunities. Following the expected onset of national oil output decline after the 2020s (in our base case), Kazakhstan may be able to comply with any announced cuts more easily, but it is debatable whether national interests would not be better served by maximizing production and exports in order to boost monetization of remaining hydrocarbon resources while possible.
- ***Investment attractiveness: Kazakhstan must undertake more far-reaching policy reforms in order to compete effectively for scarce global capital resources available to fund future upstream development.*** S&P Global's periodic comparative analysis of global upstream costs and country rankings in terms of E&P attractiveness both underscore the obstacles that Kazakhstan faces amid its bid to attract new sources of foreign investment. There is relatively little that Kazakh authorities can do to address some of the factors contributing to the country's consistent placement towards the high end of the global supply costs curve for new projects, insofar as these costs are rooted largely in geological and geographical realities, but there is still much room for fiscal and other policy improvements designed to address above-ground obstacles to upstream development that could significantly boost the country's appeal among would-be investors.

CHAPTER 2

KAZAKHSTAN'S ENERGY SECURITY

2. KAZAKHSTAN'S ENERGY SECURITY

A renewed focus on energy security, both regionally and globally, as armed conflict, economic sanctions, and reorientation of global trade patterns disrupt the international order, global supply chains, and global energy systems

2.1 Key Points

► The ongoing energy transition (that is shifting consumption from fossil fuels, particularly hydrocarbons, to cleaner renewable types of energy) will be an extremely challenging, multidecadal process that will require extraordinary changes in energy use, technology, and policy. The inherent uncertainties involved in the overall energy transition process are now compounded by additional challenges—from geopolitical turbulence—that have disrupted and subsequently reoriented world energy flows following the February 2022 escalation of Russia's armed conflict with Ukraine. Concerns about reliable access to energy in adequate quantities and at affordable prices have now put energy security at the forefront of most countries' national energy strategies, including Kazakhstan's.

► A very common energy security strategy involves efforts by countries that rely on imports of major energy commodities (particularly oil and natural gas) to source these imports from a wide variety of suppliers, or at least to avoid heavy dependence on a single source. Good examples of such diversification strategies are those deployed by mainland China with respect to oil and natural gas, the European Union (EU) for oil and gas, and the United States with respect to clean-energy minerals. Diversification of markets and export delivery routes also is an important energy security issue for energy exporters, especially now for Eurasian countries such as Kazakhstan, Russia, and Turkmenistan.

► Another important dimension of energy security, resilience, entails the ability to recover effectively and relatively quickly from unexpected events and disruptions. Three components of resilience that are critical in the response of energy systems to unforeseen geopolitical events, natural disasters, and economic shocks are: storage of hydrocarbon fuels, reliability of the electrical grid, and political (policy) resilience (public support built through transparency and equitable access to affordable energy). Hydrocarbon fuel storage capacity offers flexibility and protection against unanticipated supply disruptions for consumers and demand fluctuations or transport difficulties for producers. Increasing power grid reliability, always essential for consumers, now is needed to accommodate both greater electrification and the larger share of intermittent renewable generation entering the grid to support decarbonization efforts. A good example of the interconnectedness of electric power reliability and hydrocarbons in Kazakhstan can be found in the consequences of a brief power supply outage in western Kazakhstan in early July 2023, which disrupted upstream oil and gas production, briefly shuttered a refinery, and interrupted crude export flows on pipelines.

► A much-debated question in the current environment of disrupted and reoriented global supply chains is whether the new "energy insecurity" will delay or (conversely) accelerate the pace of the energy transition. Many signs now point toward energy security concerns accelerating the energy transition. Energy supply chain disruptions in 2022 and 2023 have had the net effect of driving up fossil fuel energy prices, making renewables more competitive on a cost basis, thereby fast-tracking both private sector investments and national-level legislation such as the Inflation Reduction Act in 2022 (IRA) in the United States. Global capex on wind and solar projects grew from $357 billion in 2021 to $490 billion in 2022, surpassing investment in oil and gas development for the first time. However, these drivers are not entirely unidirectional, as in some obvious ways energy security concerns are acting as a brake on the transition in some parts of the world. A prime example is the pushback from developing countries (especially in Africa) over the resistance of developed country institutions to support natural gas expansion, which is much less emissions-intensive than the traditional fuels that are being displaced.

► The Paris Climate Agreement also laid out a framework for the development of *extraterritorial* emission reduction schemes or mechanisms. One example is the EU's Carbon Border Adjustment Mechanism (CBAM), which went into effect on 16 May 2023. CBAM will impose a fee, starting in 2026, on imports of selected products into the EU commensurate with the degree to which greenhouse gas emissions from the production of these products exceeds a specified norm (emissions from the 10% of EU companies in the same industry reporting the highest emissions per unit of output). The sectoral scope of CBAM has now expanded to include not only electric power, cement, fertilizers, aluminum, and iron-steel, but also hydrogen, ammonia, and downstream iron-steel products. The effect on Kazakhstan would appear to be manageable, however, given that only $2.5 billion of these CBAM-related goods were exported to all countries in 2022 (not just EU members), representing only about 3% of the total value of Kazakhstan's overall exports; furthermore, the bulk of these goods were actually exported to neighboring countries, with very little going to the EU.

► One of the most important questions from a national security perspective involves the overall cost of the energy transition and its potential impacts on economic performance, jobs, wages, and vulnerable populations. Anxiety about the overall cost of the transition is a genuine concern and perhaps the single biggest obstacle to achieving political consensus on the implementation of a net-zero carbon strategy. An S&P Global assessment of the costs of the energy transition for a single developed country (achieving net zero greenhouse gas emissions by 2050 in the United States in one particular pathway) yields several important insights that may be applicable more broadly:

- ***The greatest costs are borne by energy consumers, of course, in the form of higher direct expenditures on electricity and more expensive low-carbon fuels.*** Consumer-level energy expenditures grow (in real terms) from about $1.3 trillion annually in the 2020s to $1.4 trillion–$1.5 trillion in the 2040s, or by 8-15%. For the US, this increase in consumer costs is viewed as manageable given relative income levels and expenditure patterns.

- o ***But broader societal costs incurred from the transition are largely offsetting.*** Among the direct societal costs, additional consumer outlays for durable goods (vehicles, appliances, etc.) increase, peaking at $174 billion in 2036, driven largely by the net purchase cost of electric vehicles. Other direct societal costs (i.e., the cost to taxpayers of government incentives and offsets) increase to $179 billion in 2050, peaking at $233 billion in 2040. Investment outlays by businesses and industry also rise considerably. Offsetting the increase in these direct societal costs, indirect costs (i.e., externalities based on environmental costs, such as human health) decline from $308 billion in 2023 to zero in 2050. Thus, when carbon externalities are included, society's annual net total costs actually *decline* 3% in 2050 relative to 2026.

- o ***Similarly, a net-zero power sector requires substantial additional electric power investment expenditure.*** Power sector infrastructure capex in the United States over the period 2023–50 is projected at $7.1 trillion, 85% higher than the $3.7 trillion projected in a "business as usual" scenario. When annualized, the additional electric power investment required under a 2050 net-zero scenario amounts to approximately $90 billion.

► ***Similarly, a future with net-zero greenhouse gas emissions by 2060 in Kazakhstan is viewed as being both technically possible and economically feasible.*** However, achieving this goal will require deep structural changes throughout the entire economy—from power generation and industry, to buildings and the transport sector, to agriculture and land use, including a thorough and fundamental transformation of the energy sector. Carbon neutrality will require the mobilization of substantial investments over the entire period to 2060—an estimated $666.5 billion, or roughly triple Kazakhstan's total GDP of $223.5 billion in 2022. However, when annualized over the 40-year period (2021-60), for the most part it does not exceed historic investment to GDP ratios. But the investment does take place in entirely different sectors and therefore is recouped from a different set of consumers.

► ***Energy company transition strategies have been modified, but not wholly transformed by energy security concerns.*** The response of the business sector to the energy transition has been multi-faceted, subject to some mid-course adjustment. Many hydrocarbon producers expected that they would reach maximum oil and gas output earlier and at lower levels than forecasted prior to the pandemic, and pursued portfolio diversification, mergers and acquisitions (M&A), divestments, and new clean-energy ventures to address the energy transition. But energy security concerns stemming from rising prices and disrupted supply chains resulting from the conflict between Russia and Ukraine have caused many industry executives to reassess their business plans and approaches to the transition in general. In the current strong demand environment, some "first mover" companies in the energy transition have pushed back the timetable for reducing oil and gas production. Both European and North American majors have concentrated their activities closer to home geographically, in better known geologic and political environments, while exercising increased capital discipline. National oil companies, although a diverse group, generally have continued to focus on monetizing their hydrocarbon resources as effectively as possible in an increasingly competitive investment environment.

► ***For Kazakhstan, coal can provide an important "energy security blanket" during the transition.*** Kazakhstan's indigenous coal is low-cost to produce and is readily available in large quantities, and does not require new or imported technologies to produce or deliver to consumers. Although a major drawback is its high carbon-intensity, as Kazakhstan shifts to cleaner fuels that are either imported (natural gas) or higher cost or dependent on imported technologies and equipment (solar, wind, hydrogen), low-cost indigenous coal (even as its use winds down) can serve as an important stabilizer or anchor in offsetting the inherent risks posed by these other energy sources to availability and affordability. And where coal consumption is necessary, a number of technologies can be employed during its extraction and combustion to reduce harmful emissions.

► ***Kazakhstan will remain a sizable net exporter of primary energy for the foreseeable future.*** Yet just as total primary energy exports as a share of primary energy production have declined in recent years (from 51.6% in 2020 to 48.2% in 2022), our primary energy balance projections show this trend continuing. The implication is that while energy exports will continue to play an important role in the country's economy, slowly declining energy production and rising domestic energy consumption reduce net primary energy exports substantially over the next 25 years or so, by roughly half (to 52.5 MMtoe) by 2050.

2.2 Introduction

As noted in the first chapter, world energy demand is again on an upward trajectory in the aftermath of the COVID-19 pandemic. Meeting this new demand while simultaneously transitioning from existing fossil-fuel-based capacity to lower-carbon forms of energy is an enormous challenge. All indications are that this will be a protracted, multidecadal process, involving extraordinary changes in energy use, technology, and policy.

The uncertainties involved in the energy transition are now compounded by additional challenges from geopolitical turbulence that have disrupted and subsequently reoriented world energy flows following Russia's escalation of armed conflict with Ukraine, beginning in February 2022. Concerns about reliable access to energy in adequate quantities and at affordable prices have now put the concept of energy security at the forefront of most countries' national energy strategies, including that of Kazakhstan. Yet energy security is a fluid and multidimensional concept—meaning one thing for energy producers and another for importers—with complex interrelationships with and implications for the energy transition. We begin by outlining three major dimensions of energy security—diversification, resilience, and transparency—before exploring the emerging impacts of energy security policies on the global energy transition.[1]

1 The discussion in this chapter is fundamentally informed by a number of sources, both within and outside S&P Global, the most important of which are: Daniel Yergin, *The New Map: Energy, Climate, and the Clash of Nations.* New York: Penguin Press, 2020; Daniel Yergin, *Bumps in the Energy Transition*, S&P Global, Energy Executive Commentary, 14 December 2022; and Jason Bordoff and Meghan O'Sullivan, "The Age of Energy Insecurity: How the Fight for Resources is Upending Global Geopolitics," *Foreign Affairs,* May/June 2023 (published online 10 April 2023).

2.3 Three Major Dimensions of Energy Security

2.3.1 Diversification strategies

2.3.1.1 Diversification of supply for energy importers

One of the more readily recognizable energy security strategies involves efforts by countries that rely on imports of major energy commodities (particularly oil and natural gas) to source these imports from a wide variety of suppliers, or at least to avoid heavy dependence on a single source.

China (for natural gas)

A good example of such a diversification strategy is that deployed by mainland China with respect to natural gas. Although China's domestic natural gas production over the period 2011–21 increased at a compound annual growth rate (CAGR) of 7%, gas demand growth over that same period was even faster (11%). Imports of natural gas in 2021 accounted for 45% of China's total demand of about 366 billion cubic meters (Bcm), up from 21% in 2011.[2] These imports are broadly diversified, both in terms of the mode of delivery (pipelines vs. LNG shipped by tanker) and by source country.

Although the mode of delivery varies significantly seasonally, LNG tends to account for between slightly more than half of total imports to as much as two-thirds for certain periods. LNG imports are sourced from a large number of countries, including Australia, Trinidad-Tobago, Nigeria, Indonesia, Oman, Qatar, Egypt, Equatorial Guinea, Peru, United States, Brunei, and Papua New Guinea. LNG is also procured with a diversity of contractual arrangements in terms of pricing and flexibility.

China receives pipeline gas imports from five neighboring countries: Turkmenistan, Uzbekistan, and Kazakhstan (all via the three strings of the Central Asia–China natural gas pipeline [CAGP] system), Russia, and Myanmar. Although imports via the CAGP accounted for 75% of total pipeline imports in 2021 (56% from Turkmenistan alone), the share of Russian imports (18%) is set to increase dramatically by 2025, when full contracted volumes via the Power of Siberia-1 pipeline (38 Bcm/y) would be about on par with expected Turkmen deliveries (33.1 Bcm in 2021).[3]

European Union (EU) (for oil and gas)

Unlike mainland China, where gas supply diversification reflects a decades-long government policy, the EU shifted its sources of oil and gas supply rather suddenly following Russia's invasion of Ukraine in late February 2022. Prior to the invasion, Russia supplied roughly 40% of the EU's imported gas and 25% of its imported oil. Russia already had begun to curtail pipeline gas deliveries in late 2021, but in the months after armed conflict began and the explosion on the Nord Stream pipeline in the Baltic Sea in September 2022, Russia cut off gas deliveries entirely except to a few countries in Southern and Central Europe (e.g., Hungary, Greece, Serbia, Slovakia, Austria, Italy), with the result being a reduction in pipeline gas deliveries to the EU by about 80% in 2022.[4] As a consequence, gas prices in Europe increased twelvefold and natural gas demand in the EU fell in 2022 by 55 Bcm, or 13%, its steepest drop in history.[5]

Thanks to this decline in demand, a large mandated build-up of gas inventories in storage in spring and summer 2022, as well as a surge in global LNG supplies (accompanied by the rapid construction of LNG import and regasification terminals on the Continent) and a milder than normal 2022–23 winter—the EU managed to survive the cold-season high-demand period in relatively good shape. In addition to its sudden turn to LNG (and temporarily increased reliance on coal), the EU reinforced its long-term commitment to developing renewable forms of energy; renewable generation now provides nearly half (47%) of electric power production (although renewable equipment remains heavily dependent on international supply chains).[6]

Even prior, in 2021 EU policymakers were in the midst of heated debate over whether to list natural gas and nuclear power within its “Green Taxonomy” of energy projects that European financial institutions could include within so-called “environmentally sustainable” or “green” investment (equity or debt) products.[7] Proponents for inclusion argued in favor of gas and nuclear as an essential bridge in facilitating the transition away from even more environmentally harmful energy sources (coal, fuel oil) towards a mostly renewables-based future. Opponents of funding for new gas infrastructure argued that the standard operational lifetime of new gas infrastructure would exceed the timetable required to achieve carbon neutrality (2050), thus perpetuating greenhouse gas (GHG) emissions, while opponents of nuclear cited the absence to date of a viable, safe, and long-term method of disposal of high-level radioactive waste. The dispute was resolved not soon after the onset of the armed conflict in Ukraine, and appears to reflect a realization that in the new geopolitical environment these sources will continue to be needed to meet medium-term energy demand on the Continent. On 9 March 2022, the European Commission adopted a Complementary Climate Delegated Act that included, under strict conditions, specific nuclear and gas energy activities in the list of economic activities covered by the EU Green Taxonomy. The Act, which went into effect on 1 January 2023, is a compromise of sorts that permits the following new gas and nuclear projects to qualify for funding as sustainable investments:

- Gas-fired generation of electricity, co-generation of electricity and heat, and heating/cooling from efficient district heating/cooling plants, providing that:
    - o They replace an existing coal-fired facility that cannot be replaced by renewables

2 The year 2021 is used here for comparative purposes as reflecting a more "normal" year for Chinese gas demand than 2022, when COVID measures reduced Chinese gas demand by 1% and LNG imports fell by 21%. This was a result of extremely high spot prices, reflecting a surge in European LNG demand following the onset of the Russia-Ukraine conflict.

3 S&P Global Commodity Insights, Regional Integrated, *China Natural Gas Market Profile*, February 2022, p. 34.

4 S&P Global Commodity Insights, *Europe Gas: Volatile Market Movements Reflect Short-Term Relief but Long-term Challenges Loom*, Executive Briefing, 10 May 2023.

5 https://www.iea.org/commentaries/europe-s-energy-crisis-what-factors-drove-the-record-fall-in-natural-gas-demand-in-2022.

6 S&P Global Commodity Insights, Regional Integrated Insight, *Europe's Green Industrial Policy Revival*, 5 June 2023.

7 *The National Energy Report 2021*, pp. 47–49.

- o They achieve certain targets in terms of emissions reductions
- o They fully switch to renewable or low-carbon gases (e.g., hydrogen, biomethane) by 2035

- ► Research, development, and deployment of advanced Generation IV nuclear power generation technologies that minimize waste and improve safety standards
- ► New nuclear plant projects with existing Generation III+ technologies for energy generation of electricity or heat (approvals until 2045)
- ► Upgrades and modifications of existing nuclear plants for lifetime extension purposes (approvals until 2040).[8]

United States (onshoring and "friend-shoring" of supply chains for critical minerals and renewable equipment)

Another common strategy utilized by importing countries—in this case by the United States, a major importer of critical minerals and equipment used in the production of renewable energy—is to add "own production" as a source of supply, i.e., to move as much of the supply chain as possible to domestic sources. The Inflation Reduction Act (IRA), enacted into law in late 2022, encourages the production of critical minerals in the United States and elsewhere by providing an estimated $386 billion in tax credits and loan guarantees for domestic producers of renewable energy and other clean-energy technologies over a 10-year period.[9] US policymakers believed that such a massive stimulus was necessary to prevent the country's overreliance on mainland China and other countries possessing much of the world's capacity for critical minerals (e.g., lithium, nickel, cobalt, and rare metals) and manufacturing equipment (solar panels, wind turbine components) used in the energy transition.

If anything, the geographic concentration of these critical inputs for renewable and clean-energy technologies is even greater than for fossil fuels. To take just the example of the electric vehicle (EV) battery supply chain: the world's largest supplier of lithium—a major EV battery mineral—is Australia, which accounts for 53% of global supply. The processing and refining of EV battery minerals are even more concentrated, with China currently performing around 60% of lithium and nickel refining and over 70% of cobalt refining. Meanwhile, Chinese companies manufacture more than three-quarters of EV batteries and a similar proportion of the so-called wafers and cells used in solar energy technology.[10] Such concentration of manufacturing capacity—while supporting technological advances as well as economies of scale—could also create vulnerabilities in the event of company insolvencies or other disruptions (such as port closures in 2021 and 2022 as a result of COVID-19), not to mention supplier embargoes on exports to states not deemed to be friendly (e.g., China's two-month suspension of exports of rare-earth minerals to Japan in 2010).

When onshoring is not possible, "friend-shoring"—integration with "friendly" or "like-minded" countries to form integrated markets (for clean-energy materials) or reserves—is another strategy. It reflects the belief that an interconnected global energy system can be an important pillar of energy security when integrated markets can effectively allocate supplies to ease episodic disruptions in individual countries caused by extreme weather events or political instability. One of the more successful examples of international cooperation in providing access to relatively limited supplies of energy resources is the International Atomic Energy Agency's Low-Enriched Uranium Bank, which began operations in in late 2019 and is hosted by Kazakhstan at the Ulba Metallurgical Plant. In an international environment in which uranium enrichment capacity is limited in an effort to prevent nuclear weapons proliferation, the Bank provides access to IAEA member states seeking emergency supplies of low-enriched uranium to fuel nuclear reactors. The Bank is capable of storing up to 90 tons of low-enriched uranium hexafluoride (UF_6) fuel.[11]

These emerging forms of cooperation are still evolving and can take many forms. For example, the US State Department is pushing for the conclusion of a "minerals security partnership" with 13 other governments to promote investment in critical mineral supply chains.[12] The sharing of information on critical minerals and coordination of standards and strategies for clean energy investment were among the topics of discussion at the G7 meeting of major industrialized democracies in Hiroshima, Japan in May 2023. In addition to a multilateral format, the US government has concluded bilateral agreements with individual countries, such as in December 2022 with Zambia (the world's sixth-largest copper producer) and the Democratic Republic of Congo (which produces 70% of the world's cobalt) to increase US imports of these electric battery minerals.[13] The US Export-Import Bank also is empowered to fund overseas mining operations in "friendly" countries such as Indonesia. Finally, some "friend-shoring" developments are the result of private-sector initiatives. The Australian companies Pilbara Minerals and Calix are working on a pilot project that will explore the feasibility of refining in Australia of some of the lithium produced at the Pilbara mines, rather than sending it to China for processing. A final investment decision is expected by end of 2023. Because Australia has a free trade agreement with the United States, the project (if approved) could qualify for IRA funding and could account for as much as 20% of global lithium refining capacity by 2027.[14]

2.3.1.2 Diversification of markets and transport routes for energy exporting countries

Energy security is no less salient for major energy exporters, as demonstrated by recent events, particularly for countries in the Eurasian region. Security is enhanced for energy producers by access to diverse markets through multiple reliable transportation routes. For Kazakhstan and Russia, the creation of the Eurasian Economic Union's single markets in oil/oil products and natural gas are expected to promote the security of their energy exports through the harmonization of standards and customs procedures across five member states (see Chapter 3).

8 See https://finance.ec.europa.eu/sustainable-finance/tools-and-standards/eu-taxonomy-sustainable-activities_en , as well as S&P Global Commodity Insights, Regional Integrated Insight, *Taxonomy-What's green in Europe's power market,* March 2022.

9 Producers in other countries deemed to have "free trade agreements" with the United States also are considered to be eligible for the IRA subsidies.

10 Bordoff and O'Sullivan, "The Age of Energy Insecurity."

11 *The National Energy Report 2021*, p. 218.

12 *New York Times,* 22 May 2023.

13 https://www.state.gov/the-united-states-releases-signed-memorandum-of-understanding-with-the-democratic-republic-of-congo-and-zambia-to-strengthen-electric-vehicle-battery-value-chain/.

14 *New York Times,* 26 May 2023.

Kazakhstan (oil)

The imposition of additional energy-related sanctions by the EU and other countries on Russia, following the start of that country's armed conflict with Ukraine in February 2022, resulted in a strong eastward reorientation of Russian oil flows away from Europe and toward Asia. This has had far-reaching impacts on the perceived importance and reliability of Kazakhstan's crude oil exports, which move predominantly to Europe and which mostly transit Russia. The average monthly share of Kazakhstan's crude exports destined for European markets fell by 10 percentage points, from 73% of the total during the immediate pre-invasion period (April 2018–February 2022) to 63% during the period immediately following (March 2022–February 2023).[15] The importance of transit via Russia for Kazakhstan's crude exports is illustrated by the fact that 64.3 million metric tons (MMt) of crude—roughly 94% percent of all exports—transited via Russia in 2022 according to the Kazakh Energy Ministry data; the lion's share of these transit volumes are exported via the Caspian Pipeline Consortium (CPC) pipeline route while a significant portion is also carried by Transneft pipeline.[16]

Repeated problems on the CPC pipeline in the spring and summer 2022, mainly related to maintenance and other issues and to storm damage to two of three offshore moorings at CPC's Yuzhnaya Ozereyevka terminal on the Black Sea (with each mooring shuttered for repair for at least a month), severely disrupted export capacity on occasion during the August–November period and increased Kazakh policymakers' apprehensions about its reliability and the wisdom of such heavy reliance on Russian transit. As a consequence, officials began pushing for more exports via other routes, and particularly westward across the Caspian Sea and via the Baku-Tbilisi-Ceyhan (BTC) pipeline. Azerbaijan's state oil company SOCAR and KMG concluded an agreement in November 2022 to ship 1.5 MMt of Kazakh oil along BTC in 2023, with the view that perhaps twice this volume ultimately could be exported via this route without major upgrades. This agreement, together with some increases in exports on the Kazakhstan-China pipeline (KCP), have somewhat assuaged near-term concerns over the potential loss of access to export markets. However, long-term apprehension remains. Kazakh Energy Ministry officials believe the current capacity of all export routes other than CPC is only 16.5 MMt, or only about one quarter the volume of 2022 exports.[17]

Kazakh concerns about security are not limited to transit routes, but increasingly extend to sustaining oil production at present levels. KAZENERGY representatives recently sounded a warning that output from mature "legacy" fields in the country is now declining at a faster pace than reserves are being added elsewhere through exploration and new field development. Because the output of these fields (owned by KMG, CNPC-Aktobemunaygaz, and numerous independents) is the supply source for the domestic market, there is increasing risk, as early as 2025, of a domestic shortage of legacy crude to meet domestic refined products demand. They urged, among other things, development of a support mechanism to incentivize operators of these fields to invest in new technologies to maximize extraction and to continue to supply the domestic market.[18]

Turkmenistan (gas)

Turkmenistan finds itself similarly looking for alternative routes for the export of its natural gas. It presently has limited options, with most of its natural gas going to China, although Russia also remains important, although highly volatile in terms of sales volumes. Following the imposition of Western sanctions on Russia and the curtailment of Russian gas exports to Europe, Gazprom again chose to reduce imports from Turkmenistan, which fell by two-thirds in 2022.[19] Gas exports to Iran (and to Azerbaijan via Iran) also have been an important diversification option for Turkmenistan. On 30 May 2023, Iran's oil minister announced that a new contract for imports of 10 MMcm/d (3.65 Bcm/y) of Turkmen gas would allow deliveries to resume in June.[20]

Russia (oil)

A major energy exporter affected even more directly by Western energy sanctions has been Russia itself, which essentially has been forced to reorient its oil trade eastward to Asia. The conflict with Ukraine has imposed steep costs on Russia, with the EU and other Western nations imposing bans on seaborne crude imports from Russia and refined products.

For now, Russia has successfully redirected its crude exports, which grew by more than 12% overall in 2022, with India and China emerging as the major buyers. However, this comes with the use of more expensive long-distance waterborne hauls from western Russian ports.[21] Product sales also appear to have held up reasonably well for now (down only 7.6% in 2022), finding markets in Asia, Turkey, Brazil, western Africa, and the Middle East. S&P Commodity Insights projects that Russia's refinery throughput (about half of which historically is exported) will contract given the difficulties of maintaining product exports.[22] In short, an inability to fully compensate for the loss of large portions of the Western products markets may leave Russian refiners little option but to curtail output.

Russia (gas)

Although not similarly legally banned, natural gas deliveries to Europe also have fallen dramatically, as Russia has refused to sell to many customers unwilling to switch to payment in rubles. The major challenge is where to redirect the approximately 90 Bcm of gas now no longer going to Europe. Europe formerly was by far Russia's largest export market, accounting for two-thirds of total 2021 exports (176.5 Bcm of 263.5 Bcm). As a consequence, Russia's overall gas exports fell by 30% in 2022, and will fall further in 2023.[23]

15 *Kazakhstan Newsline,* 13 April 2023; https://astanatimes.com/2023/04/expert-kazakhstan-can-increase-oil-supplies-to-asian-markets/.

16 *Kazakhstan Newsline,* 27 March 2023; https://www.zakon.kz/6385866-chto-nuzhno-predprinyat-kazakhstanu-dlya-diversifikatsii-postavki-nefti-rasskazala-ekspert.html.

17 *Kazakhstan Newsline,* 13 April 2023; https://astanatimes.com/2023/04/expert-kazakhstan-can-increase-oil-supplies-to-asian-markets/. A more thorough analysis of the routing of Kazakhstan's crude exports can be found in Chapter 5 of this report and in S&P Global Commodity Insights, Strategic Report, *Kazakhstan's Current Oil Export Diversification Push: What role for trans-Caspian routes?* 28 June 2023.

18 KAZENERGY Association of Oil, Gas, and Energy Sector Organizations, presentation at Future Energy Dialogue forum, Astana, Kazakhstan, 26 May 2023.

19 See S&P Global, Commodity Insight, *Turkmen Gas Production Apparently Declines in 2022?* 5 June 2023.

20 *Argus Eurasia Energy,* 1 June 2023.

21 See S&P Global Commodity Insights, Russia Watch, *Damage Control: How is Russia's energy industry adapting to intensified Western sanctions and new domestic political and economic constraints?* March 2023, p. 27.

22 Russia Watch, *Damage Control*, p. 27.

23 Russia Watch, *Damage Control,* pp. 20–23.

A large portion of Russia's gas production is now effectively stranded, as its LNG development is hampered by sanctions on imports of gas liquefaction equipment. China is widely viewed as the only market large enough to eventually take some of this stranded gas, although the build-out of infrastructure to support this reorientation, while now under way, will take a good number of years. Russia already is a strategic gas supplier for China, accounting for 10% (10.4 Bcm) of its gas imports in 2021 and 15.4 Bcm in 2022. The two countries' gas ties will strengthen further given the ramp-up of the 38 Bcm/y Power of Siberia-1 (POS-1) project, which is expected to reach contracted volumes in 2025, and the recently announced (February 2022) 10 Bcm/y Far East gas pipeline contract. Yet the conclusion of these agreements increases total contracted piped volumes between Russia and China to only 48 Bcm/y, just slightly more than half the decline in Russian piped gas exports to Europe that occurred in 2022. The big hope for the future is the 45–50 Bcm/y Power of Siberia-2 pipeline that will move gas from West Siberia to China, transiting Mongolia. No commercial agreement has yet been reached.

Perhaps it is not surprising, in this context, and given Russia and China's prominent roles in the Shanghai Cooperation Organization, that a recent "Statement by the Council of the Heads of State of the Shanghai Cooperation Organization on Energy Security" (Samarkand, Uzbekistan, 16 September 2022) emphasized the need to strengthen "interaction between the supplying countries, transit countries, and consumer countries to guarantee the security and stability of international channels of energy commodities transportation and to ensure the uninterrupted functioning of the global production and supply chain."[24]

Trilateral discussions (Kazakhstan, Russia, and Uzbekistan) on utilization and expansion of natural gas infrastructure in Central Asia

One development that appears to hold some promise for improving energy security for Russia (by opening additional markets) as well as Kazakhstan and Uzbekistan (to secure additional supplies), is the ongoing discussion among the three countries to coordinate activities to upgrade natural gas infrastructure in order to support higher levels of intra-regional and international gas trade.

The partnership aims to:

- deliver Russian natural gas to Uzbekistan using Kazakh transit; Uzbekistan agreed a gas supply contract with Gazprom to import 2.8 Bcm/y under a two-year deal, starting at 9 MMcm/day later this year using the Soviet-era Central Asia–Center pipeline system through a reversed flow regime.[25]
- facilitate Russian gas exports to Kazakhstan as well, where domestic supplies of commercial gas are now strained.
- Russian supply would free up some additional domestic gas for continued Kazakh and Uzbek exports to China.[26]
- Russia also is seeking to make it possible for Russian gas to enter the CAGP for export on to China or eventually penetrate farther southward via new projects targeting exports to South Asia.[27]

2.3.2 Resilience

A second important dimension of overall energy security is resilience, which refers to the ability of energy systems to recover relatively quickly from an unexpected event or shock. The focus of this section is on three components of resilience that are critical in the response of energy systems to unforeseen geopolitical events, natural disasters, and economic shocks: storage of hydrocarbon fuels, reliability of the electrical grid, and political (policy) resilience (involving public support through transparency and equitable access to affordable energy).

2.3.2.1 Storage

Hydrocarbon fuel storage capacity offers flexibility and protection against unanticipated supply disruptions for consumers and demand fluctuations or transport difficulties for producers. One of the more widely utilized safeguards against supply disruptions deployed internationally are strategic petroleum reserves. The International Energy Agency (IEA), an intergovernmental organization with 31 member countries founded in 1974 in the wake of the Arab Oil Embargo, maintains a Strategic Petroleum Reserve (SPR) program.[28] The goal of the program is to ensure there is adequate oil and refined products storage capacity to enable the participants to mitigate (and flexibly respond to) market impacts driven by sudden changes in demand (of consumers for product and refineries for crude) or unanticipated disruptions of crude and product imports or exports (due to upstream outages, accidents on pipelines and at ports, natural disasters, trade embargoes, etc.).

In accordance with the Agreement on an International Energy Program (1974, amended in 2018), each net-importing IEA country is required to hold oil stocks (crude and product) equivalent to at least 90 days of net oil imports and be prepared to release emergency stocks to the market in response to a supply disruption (see Figure 2.1 SPRs of select member and associate IEA countries (February 2023)). The most recent emergency release of oil (120 million barrels [MMb] of crude and refined products) from member-country SPRs was announced on 1 April 2022 in an effort to calm global markets as fuel supplies tightened after the start of the Russia-Ukraine conflict (Brent crude had spiked to as high as $130/b). One day earlier, the United States had announced that it would make available up to 180 MMb from its

24 http://eng.sectsco.org/documents/.

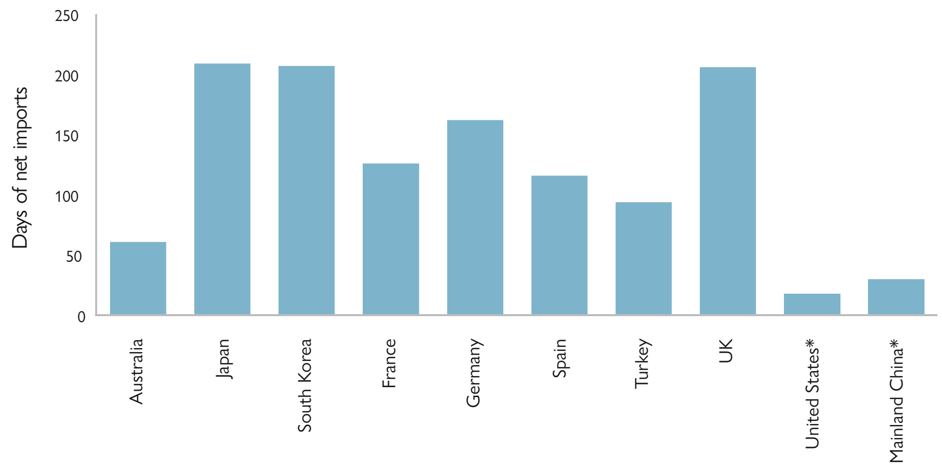
25 https://kz.kursiv.media/23-06-16/zhnb-qazaqgazgazpromuz/.

26 Another dimension in the discussions is a proposal by Kazakhstan to construct a new international gas pipeline from Russia that would run through Kazakh territory and connect to China, in the process delivering natural gas to Kazakhstan's eastern regions via the route Kostanay - Astana - Pavlodar - Semey - Ust-Kamenogorsk.

27 Energy Intelligence, *Nefte Compass*, 21 June 2023, p. 4.

28 During the 1973 Arab-Israeli War, Arab members of the Organization of Petroleum Exporting Countries (OPEC) imposed a crude oil embargo against the United States in retaliation for the US decision to re-supply the Israeli military and to gain leverage in the post-war peace negotiations. Arab OPEC members also extended the embargo to other countries that supported Israel, including the Netherlands, Portugal, and South Africa. The embargo both banned petroleum exports to the targeted nations and introduced cuts in oil production. The 1973 Oil Embargo acutely strained a US economy that had grown increasingly dependent on foreign oil. The onset of the embargo contributed to an upward spiral in US oil prices, with global implications. The price of Brent crude first doubled, then quadrupled, imposing skyrocketing costs on consumers and structural challenges to the stability of entire national economies. See https://history.state.gov/milestones/1969-1976/oil-embargo.

Figure 2.1 SPRs of select member and associate IEA countries (February 2023)



Notes: Crude and refined products, in crude oil equivalent. *Days of consumption.
Source: S&P Global Commodity Insights, International Energy Agency.

SPR over a six-month period. The IEA action represented the fifth (and largest) emergency release in its 48-year history.

IEA member countries have flexibility in how they meet stockholding obligations: in the form of government stocks held exclusively for emergencies (typically crude), stocks held for commercial purposes (both crude and products) by refiners and wholesalers, and stocks held in third countries under bilateral agreements. Some IEA members (Canada, Norway, Mexico, and the United States) are net exporters, and are not obligated to abide by the IEA reserve requirements. Nonetheless some, such as the US, maintain their own SPRs under lower reserve requirements. The capacity of the US SPR is 714 MMb (about 95.2 million metric tons [MMt]). As of 19 May 2023, it held 357.95 MMb (down by fully one-third year on year as a result of releases designed to lower domestic gasoline and diesel prices)—equal to 17.6 days of crude supply at average 2022 US consumption levels (20.28 million barrels per day [MMb/d]).

Likewise, mainland China—now the world's largest oil importer as well as a major producer whose petroleum companies are active in many countries of the world—has its own approach to strategic petroleum storage. The IEA collaborates with China and certain other non-member countries (e.g., India, Indonesia, and Thailand) through its multilateral Association Agreement, which allows associate countries (currently there are 11) to participate in IEA meetings and work with IEA member-states on energy security, energy policy, data exchange, and technology matters. It also maintains less formal, bilateral cooperation agreements with other countries. China does not officially report its SPR volume, although it is believed to be more than 400 MMb with a capacity of 500 MMb. The state plan calls for reserves of 475.9 MMb, equal to about 30 days of supply at 2021 daily consumption levels (15.8 MMb/d).

Disruptions of crude shipments via the CPC pipeline in 2022, the 2020 contraction in global oil demand from COVID-19, and Kazakhstan's current efforts to redirect a higher share of its oil exports via the Caspian Sea highlight the importance of storage in supporting operational flexibility. In addition to responding to the uncertain transit environment for its crude exports, Kazakhstan needs to ensure it has adequate and flexible storage to accommodate *possible* changes in:

- ***Domestic crude and product demand,*** i.e., changes required in the refinery product slate reflecting the dynamics of the domestic market as well as potential price increases resulting from domestic market liberalization and/or EAEU harmonization
- ***Product imports,*** e.g., increases by Kazakhstan of imports of certain products (such as jet fuel or bitumen) from Russia, the prices of which could become more attractive for Kazakh buyers owing to loss of Russia's traditional export markets in Europe
- ***Product exports,*** i.e., increases in Kazakh exports of certain products (mazut) to markets (such as the US and EU) that have become closed to Russian exports or where they may be more competitive due to geographic proximity (Central Asia)

In a move that signals the increasing importance of access to adequate storage, on 5 May 2022 Kazakhstan's Prime Minister instructed the Ministry of Energy to develop a unified regulation for petroleum products storage at refineries for all market participants, in order to prevent preferential treatment for some at the expense of others. And on 20 May 2022, Kazakhstan's Ministry of Energy announced plans to add 200,000 tons of refined products to a new reserve of major fuel types created in Q1 2022, sufficient to meet nearly one month of projected demand. The new supplies will add to stocks already held by KazMunayGaz and Kazakhstan Temir Zholy, and are intended to protect against an emergency situation or an unexpected spike in demand. Refined product supply can tighten when one or more of the country's three large refineries are shut down for maintenance or power disruption (such as occurred at the Atyrau refinery in July 2023). In 2023, maintenance shutdowns were scheduled for all three major Kazakh refineries: Shymkent went offline from March 15 to April 7 (and additional unplanned maintenance during part of July shut down a catalytic reforming unit); Pavlodar was down from June 20 to July 19; and Atyrau was scheduled for an overhaul in October. In the past, lengthy shutdowns of two refineries in the same year for repairs have led to at least temporary shortages of gasoline and diesel, especially during times when domestic prices are rising.[29]

Kazakhstan's existing oil storage capacity, established mainly to support operational needs of the transportation system, presently appears adequate to cover domestic refinery needs in the event of a short-term disruption to regular supply. The bulk of crude storage in the country is held by the pipeline companies. KTO has nearly 1.2 million cubic meters of storage used for the operation of its pipeline system, which is sufficient to hold about 1.0–1.1 MMt of crude oil. This represents the equivalent of about 4 days of national oil production. Similarly, CPC holds 1.3 million cubic meters of storage (at its marine terminal on Russian territory). So between them, they can store the equivalent of about 10 days of national oil production. The refineries also have operational storage for their crude oil stocks and for their finished products, but these volumes are relatively small (also representing only a few days of operations). What Kazakhstan does not have is strategic storage for crude to offset sudden reductions in export demand or export capacity (pipelines); production itself must be adjusted in such circumstances.

The current actual (operational) natural gas storage capacity in Kazakhstan is about 2.5 Bcm. However, in order to achieve the benchmark level of 20% of storage capacity relative to total annual gas consumption in the country, underground storage capacity should be 3–4 Bcm today, 6–7 Bcm by 2030 (at the consumption level envisaged in state planning documents), and 8–9 Bcm by 2030 assuming continued robust demand growth.

The key locations where additional capacity is needed are the areas near the Saryarka pipeline, to ensure uninterrupted supplies to Astana, and areas in southern Kazakhstan, taking into consideration the limited capacity of the Beyneu-Bozoy-Shymkent pipeline during the autumn-winter period. There are several options for increasing storage capacity. The least costly strategy, and the one that could be most quickly implemented, would be to bring the existing Bozoy and Akyrtobe underground storage facilities to their design capacity. The total design capacity of the three current underground gas storage facilities is 4.65 Bcm, which would be sufficient to reach the benchmark storage indicator at current consumption volumes.

However, given the projected future growth in consumption, it is necessary to take additional steps to increase capacity—through the creation of new underground gas storage facilities. In Kazakhstan, there are a number of potential sites for these facilities (depleted gas fields, salt deposits, etc.), but the most promising in terms of location and development possibilities are the Zhezkazgan-Karakoinsky salt deposits. However, the potential storage capacity at this new site does not exceed 1 Bcm in the medium term. QazaqGaz has developed and sent to the Ministry of Energy a draft Roadmap for the expansion of existing and creation of new underground gas storage facilities in Kazakhstan, and the government is considering the issue of financing.

29 In April 2023, the government increased the maximum allowable retail prices of AI-92 and AI-93 gasoline by around 11%. At the same time, the maximum allowable retail diesel price was raised by about 20% for Kazakh citizens (a higher diesel price applies to foreign citizens since August 2022). For details on pricing, see Chapter 3 and, especially, Chapter 5.

2.3.2.2 Electricity system reliability

Estimates by the IEA indicate that if the world is to reach the goal of net-zero carbon emissions by 2050, *fully half* of global final energy consumption will need to be in the form of electricity, up from only 20% at present. And nearly all that electricity will need to be produced from low-carbon sources, up from only 38% today. This increased electrification will place a major strain on national electricity systems—the infrastructure for electricity generation, transmission, and distribution. This strain probably will be compounded by more extreme weather, wildfires, and other risks related to climate change.[30] In one of the S&P Global's power-sector deep decarbonization scenarios (Multitech Migration®), for example, the world will need to add about 28,000 GW of "clean" generation capacity—wind, solar, nuclear, hydro, other renewables, and battery storage—between now and 2050, or more than five times the pace achieved during the 2010s. This represents a total investment of approximately $20–30 trillion for power generation alone; transmission and distribution will require even more capex.[31]

Balancing and flexible generation. The increasing share of intermittent renewable energy within the grid will need to be matched by adequate balancing resources and flexible (dispatchable) generation capacity.[32] One way of mitigating balancing and dispatchable power challenges is improved interconnection of different regional and/or national grids using high-voltage links, so that supply deficits (or surpluses) can be mitigated by sizable inter-grid transfers. But a more important approach to reinforcing grid balancing capacity (in addition to increasing electricity storage) is the creation of "capacity markets" that pay generators of flexible power to build and maintain capacity that may be needed only during relatively short periods of peak demand. Companies whose resources are needed only infrequently nevertheless must be able to remain in business to support reliable supply even when they are idle for long periods.

Digitalization and automated control. Distributed energy systems (with electricity entering the system from numerous small generation points such as rooftop solar PV or small wind farms) demand higher levels of grid and system performance than highly centralized ones; this will require more digitalization and automated control systems. It will also require more ancillary services (frequency control and switching, reactive power support, spinning reserves, etc.) to maintain reliability. Digitalized "smart grids," dynamic line ratings, advanced power flow control, intentional islanding schemes (enabling distributed resources to supply local loads when the grid cannot), and other technical and operational approaches all can play a role in increasing system reliability. And end-user power consumption can be better monitored and controlled via automated demand management systems operating at variable time scales (diurnal, seasonal).

30 Bordoff and O'Sullivan, "The Age of Energy Insecurity."

31 S&P Global, Global Power and Renewables Strategic Report, *Decarbonizing Electric Power: Key challenges amid a global energy crunch and climate negotiations,* 16 November 2021, pp. 4–5. One estimate of the annual expenditure to 2050 needed just to ensure the reliability of the expanded grid is upwards of $1 trillion ("The Ultimate Supply Chains," *The Economist* [Technology Quarterly Supplement], 8 April 2023).

32 Balancing is the process of matching the volumes of power generation and consumption within a grid, which is greatly complicated on the supply side when the share of intermittent renewable generation capacity increases. Flexibility (dispatchability) refers to the ability of a generation source to rapidly ramp up or ramp down the volume of electric power generation in response to demand fluctuations.

Long-duration energy storage. Further penetration of renewable power would be greatly facilitated by the development of much higher capacity for long-duration storage of electricity than is currently available. Even as battery costs continue to come down and technology improvements enable batteries to store electric power over longer periods, they are unlikely to get cheap or large enough to perform the role of system “firming” on their own. As a result, another class of resources is needed to ensure reliability, namely power generation assets that are both “low carbon” and “firm” (i.e., consistently dispatchable for extended periods of time without interruption). Until these next-generation assets (e.g., green hydrogen, geothermal, pumped hydro) become commercially available, some existing zero-carbon (nuclear) or low-carbon (natural gas) technologies that are both firm and flexible must continue to play a major role.[33] In the meantime, the mismatch over the coming decade between the rate of renewable capacity build (rapid) and dispatchable capacity (stagnant or even declining as a result of planned coal and nuclear plant retirements) will present a major challenge to electricity system reliability.

Long-distance electricity transmission. The geographic mismatch between regions with highly favorable renewable potential and regions of concentrated high electricity demand in many countries (e.g., mainland China, the United States, Germany) makes it important to significantly expand high-voltage transmission lines to better to respond to seasonal demand fluctuations. HVDC (high voltage, direct current) lines are a solution for long distance transmission (exceeding a few hundred kilometers), but they have drawbacks such as expensive conversions between direct and alternating current (using insulated gate bipolar transistors) and the requirement of single injection node and withdrawal node. HVDC lines also have important applications in grid linkage, enabling the connection of independent grids that cannot simply be merged into a bigger synchronous system.

A recent important lesson for Kazakhstan. A recent example of the importance of maintaining power system reliability in Kazakhstan, and its interconnection with the country's energy and economic security more broadly, can be found in the consequences of a brief disruption of power supply in western Kazakhstan in early July 2023. On 3 July an emergency shutdown of a generator at the MAEK thermal power station led to the shutdown of the 220 kV Beyneu-Tengiz transmission line. As a result, Mangystau Oblast was effectively cut off from Kazakhstan's main grid, and the effects then cascaded to Atyrau Oblast, with interruption of power supply across the region, including important consumers such as upstream oil producers, the Atyrau oil refinery, and export pipelines.[34] During the outage, consumers in Atyrau and Mangystau oblasts were temporarily supplied with power from Russia (130 MW via a 220 kV transmission line (Uralsk-Atyrau)). The situation was resolved by 7 July, when full power output at MAEK was restored, but the power cuts had widespread effects on oil and gas production, refining, and transportation.[35]

For a detailed discussion of Kazakhstan's electric power system and steps needed to increase its reliability, see Chapter 8.

2.3.2.3 Energy policy resilience

To sustain effective energy security over an extended period, policies must be in place that garner public support, creating a virtuous cycle of improving economic prosperity and quality of life where access to abundant, reliable, and affordable energy are widely available to all participants, and energy policies and investment are aligned to maintain this expectation. This is not an easy task in countries where access to electricity remains elusive, for example. Ensuring energy access raises the difficult questions involving how best to connect underserved communities to affordable energy without compromising the reliability of energy systems. Many multilateral development banks are seeking to address energy poverty through a combination of grid expansion and distributed renewables. Financial aid commitments from developed countries—such as those promised in the Paris Climate Agreement—can assist in this effort. However, current levels of funding are inadequate to rapidly expand electricity services and improve reliability for developing countries.

Kazakhstan is an example of a country that thus far has done a reasonably good job at providing equitable access to affordable energy for its population. One of the three dimensions of the World Energy Council's annual World Energy Trilemma Index ranking of countries' energy system performance is Energy Equity, which measures a population's access to electricity and the affordability of electricity, natural gas, and oil products.[36] In the most recent ranking on the Energy Equity component (2022, using 2021 data), Kazakhstan ranked in the upper one-third of countries (36th of 127 ranked countries), basically on par with developed nations in northwestern Europe, Arab Persian Gulf states, and United States. Thus, it appears that Kazakhstan's challenge rather is how to sustain widespread availability without unduly compromising affordability—i.e., how to incentivize domestic deliveries of commercial gas, electricity and heat, and crude for domestic refining through effective price and taxation policies that do not increase energy prices so rapidly and by such magnitude that they spark a public backlash (as occurred in Sri Lanka in 2022, when refined products shortages and price increases led the government to deploy the military to fuel stations to quell civil unrest).

Land use conflicts. A major challenge to sustaining energy policy resilience in the transition to lower-carbon forms of energy involves emerging land use conflicts. Renewable power generation has a relatively low “power density” (i.e., power output possible per unit of land utilized) vis-à-vis conventional thermal power production. Therefore, the land area needed for decarbonized electric power generation will ultimately be orders of magnitude greater than that used for thermal generation.

To some extent renewable energy developers can seek to mitigate land use competition by targeting locations where such competition with alternative land uses is minimized. One option would be to locate renewable generation on otherwise less productive tracts of land, such as areas without water or with steeper slopes or polluted soil. Another strategy might involve repurposing the sites of shuttered or soon-to-be-closed coal- and

33 *Decarbonizing Electric Power,* p. 3 and S&P Global, Global Power and Renewables Strategic Report *Thermal Revival: The global quest for dispatchable long-duration power sources,* June 2023.

34 *Interfax Central Asia & Caucasus Business Weekly,* 4 July 2023.

35 *Argus Eurasia Energy,* 6 July 2023, p. 4; Energy Intelligence, *Nefte Compass,* 5 July 2022, p. 4.

36 https://www.worldenergy.org/publications/entry/world-energy-trilemma-index-2022.

gas-fired plants for renewable power generation. Not all traditional power plant sites are optimal for wind or solar generation, but they do have the advantage of already having power grid connections.[37]

Another option for avoiding *land* use competition is arguably to locate offshore. In fact, some population-dense geographies, such as South Korea and Indonesia, already consider floating PV a third solar tier along with rooftop and ground-mount installations. And in densely populated Europe, offshore wind already is a centerpiece of the energy transition. However, even location offshore does not entirely remove the developer from conflicts emerging over competing uses (e.g., with fisheries, conservation, shipping, and tourism interests). Land use competition is not presently a major impediment to sustainable energy development in Kazakhstan, given the country's large land area and low population density, although it may eventually become a factor in the vicinity of major urban centers.

2.3.3 Transparency

The sharing of information is shown to be a highly effective response to an energy security concern. The International Energy Agency, for example, was created in 1974 by the United States, Canada, Japan, and several European countries in response to the Arab Oil Embargo which had resulted in acute refined product shortages and skyrocketing prices. At the same time, the dearth of accurate data on prices and supplies complicated governments' efforts to devise policies and effectively respond to the crisis. The lesson learned from that crisis was clear: "good data allows markets to function, prevents panic, and deters the speculation that exacerbates price spikes, volatility, and shortages."[38] Over the subsequent decades, data on energy provided by such large international organizations as the IEA, OPEC, International Gas Union, and World Nuclear Association have supported informed decision-making, by governments, industry, and consumers about production levels, demand, and reserves and their influence on pricing. A clean-energy economy will require the same kind of transparency and information-sharing effort for critical minerals, hydrogen, ammonia, and renewable energy equipment.

2.4 Energy (In)security and the Pace of the Energy Transition

A much-debated question in the current environment (of post-pandemic economic recovery and disrupted and reoriented global supply chains) is whether the new "energy insecurity" will delay or (conversely) accelerate the pace of the energy transition. In addressing this question, it should first be noted that the interactions between policies enacted for the purpose of enhancing the energy security of individual countries and ongoing efforts to shift to lower-carbon energy systems to combat climate change are multifaceted, and complex, and the effects are sometimes contradictory.

Another difficulty lies in the popular (mis)conception of the energy transition, and how it is expected by many to unfold. Historical, global-scale transitions in energy (e.g., the transition from wood to coal, and subsequently from coal to petroleum) were protracted, taking many decades if not a century or more to fully run their course. Yet, sensing the urgency of responding to climate change, activists have rapidly ratcheted up emissions reduction targets and the emissions reduction timetable over the period since the Kyoto Protocol (1997) operationalized the United Nations Framework Convention on Climate Change (UNFCCC, 1992), by committing signatory countries to specific emissions reduction pledges. Not only was the rather nebulous goal of holding the global mean temperature increase to below 2°C (relative to pre-industrial levels)—established at COP21 in Paris (2015)—subsequently tightened to the previously aspirational 1.5°C target (now canonized as the level necessary to avert catastrophic impacts from climate change), but a deadline (2050) for net-zero carbon emissions in support of reaching this target was enunciated for the first time.[39]

The anxiety over the issue obscures the fact that the world has already warmed by an estimated 1.2°C relative to pre-industrial levels, and that another decade of emissions at or near current levels would erase what has been estimated as the entire remaining "carbon budget" (estimated future GHG emissions allowance) needed to remain below the 1.5°C threshold. The chances of meeting the 1.5°C target are now exceedingly small—our S&P Global Inflections base case envisions 2.4°C of warming out to 2100—as long as the world's two most populous countries (and major emitters) do not plan to reach net zero until 2060 (China) and 2070 (India).[40] Complicating the path still further are the growing impacts of natural events believed to be related to climate change on plans to curb emissions, such as wildfires and methane releases from thawing permafrost.[41] In summary, the campaign to reach net zero will be an extremely challenging, multidecadal process that requires extraordinary changes in energy use, technology, and policy over the next three decades. A less ambitious, and likely more realistic perspective on the energy transition is that it can be said to have occurred when hydrocarbons account for less than 50% of primary energy—through a process that entails more gradual changes than presently deemed necessary in the popular narrative, and more *adaptation* to a changing climate than currently assumed.

Despite these challenges in conceptualizing energy security and the energy transition, over the long term, the evidence supports the idea that a transition toward more widely available forms of renewable energy (wind and solar power) will fundamentally enhance energy security. For instance, some of the early discussions about energy security in the West—during the Arab Oil Embargo of the 1970s when there was widespread concern

37 See "Trading Coal for Sunlight, Power Plants Get New Life," *New York Times,* 16 July 2022.

38 Bordoff and O'Sullivan, "The Age of Energy Insecurity."

39 The 2050 date gained traction as a hard deadline following the publication of a UNFCCC report in 2018 that estimated that achieving the 1.5°C target would require net-zero emissions around mid-century (*The Economist,* 5 November 2022).

40 S&P Global Commodity Insights, Strategic Report, *Energy and Climate Scenarios, Inflections (2023-50): The S&P Global Commodity Insights base-case view of the energy future,* July 2023, p. 3.

41 For instance, wildfires accompanying drought conditions in California are estimated to have put twice as much carbon in the atmosphere in 2020 than had been reduced by all of the state's decarbonization policies over the period 2013–19. Similarly, North American and Eurasian wildfires in 2021 produced higher CO_2 emissions than officially recorded by any single country other than China, the United States, and India (David Wallace-Wells, "One Grim Climate Lesson from the Canadian Wildfires: For all our plans to control emissions, humans are no longer fully in charge," *The New York Times Magazine,* 30 July 2023).

over the perceived limits to and exhaustion of global oil supply—viewed the transition to renewable energy as a key part of the solution. As we observed in *The National Energy Report 2021:*[42]

> The current [2021] iteration of the energy transition, focused on decarbonization, has a precursor in even longer-standing 20th century concerns over *energy security and access*. Even as recently as the first decade of the 21st century, conventional wisdom still held that the world's hydrocarbon resources were limited and their continued utilization was threatened by looming shortages, given seemingly inexorable demand growth (as exemplified by fears of reaching "peak oil"). Further, the unequal distribution of fossil fuel energy resources among countries of the world was viewed as conferring a permanent economic advantage to so-called "petrostates" vis-à-vis countries lacking substantial oil and gas endowments. Under this view, a "transition" toward renewable energy sources such as wind and solar power, which were ubiquitous (and coincidentally also zero-carbon), offered a path to overcome both energy scarcity *and* its unequal spatial distribution. Of course, these more traditional motivations supporting an energy transition – i.e., the desire to possess adequate energy supplies not subject to exhaustion or political manipulation – have now been eclipsed by the more urgent need to respond to *climate change* . . .

It is considered axiomatic that the energy transition can enhance energy security *over the long term* by diversifying supply sources and suppliers. Transportation, for example, most of which currently runs on oil, would be less vulnerable to fuel supply disruptions in a world where most vehicles are electrified, as electricity can be generated from multiple energy sources. Furthermore, a more electrified world would also be less subject to import disruptions caused by disputes among countries and accidents at key geographic chokepoints.[43] But the reality is actually more complex: the transition largely involves switching one set of security concerns for another.

Particularly in the near term it seems in many instances that the energy transition, particularly in its early or intermediate phases, may increase insecurity. As oil demand slows and then ebbs globally, global oil production will become increasingly concentrated in fewer countries where incremental and replacement barrels can be produced at lowest cost (which usually also means the lowest carbon footprint as well). Because many of these countries are located in the Middle East, the share of production from the OPEC+ group of producers will increase, by some estimates from 45% today to 57% by 2040.[44] But it is worth noting that the shift to a net-zero energy economy will not eliminate energy security concerns; the geographic concentration in the production and processing of clean-energy minerals is even greater than for hydrocarbon production.

Nonetheless, many signs now point toward energy security concerns *accelerating* the energy transition.[45] The energy supply chain disruptions in 2022 and 2023 had the net effect of driving up fossil fuel prices, making renewables more competitive on a cost basis. Global capex on wind and solar projects grew from $357 billion in 2021 to $490 billion in 2022, surpassing investment in oil and gas development for the first time. Additional signs of an accelerating build-out of low-carbon energy include:

- ***United States.*** The IRA earmarks $386 billion in tax credits and subsidies for renewables and other green energy technologies over a 10-year period. This long period removes year-to-year uncertainties among potential investors about the availability of funding. Since enactment of the legislation, nearly 100 new clean-energy manufacturing facilities or factory expansions have been announced, involving more than $70 billion in new investment, as well as plans for the construction of 96 GW of new renewable electricity generation capacity.[46]
- ***European Union (EU).*** The EU plans to make available at least $270 billion in funding for clean-energy companies and has brought forward its target for the doubling of installed solar capacity to 2025 from 2030.
- ***China.*** Mainland China's 14th Five-Year Plan, unveiled in late December 2021, for the first time has a target for the share of renewables in power generation (33% by 2025).
- ***Japan.*** Japan is pursuing a new "green transformation" plan (10 February 2023) that includes expansion of nuclear, hydrogen, and other low-emissions technologies.
- ***Global renewable capacity.*** The IEA now expects global renewable electricity generation capacity will more than double between 2022 and 2027, a 30% increase over its capacity estimate in 2021. It estimates that renewables will overtake coal as the largest source of electric power generation worldwide by 2025.[47]

Broadly, according to Fatih Birol, the Executive Director of the IEA: "It's notable that many of these new clean energy targets aren't being put in place for climate reasons. Increasingly the big drivers are *energy security* [italics added] as well as industrial policy. . ."[48]

However, the directionality is not entirely toward acceleration, as in some obvious ways energy security concerns are delaying the energy transition in certain parts of the world. A prime example is the pushback from developing countries (especially in Africa) over what they view as the resistance of European institutions in helping them build out their energy infrastructure, particularly for natural gas. Developing countries believe the apparent singular emphasis on reducing emissions in the developed world needs to be balanced in their case against other urgent priorities—health, poverty reduction, and economic growth. In the immediate term, striving not to "let the perfect be the enemy of the good," they are seeking to increase their consumption of natural gas to reduce indoor pollution, promote economic development and job creation, and, in many cases, eliminate the emissions and pollution that come from burning coal and biomass—the most carbon-intensive fuels in use.

42 *The National Energy Report 2021*, p. 45.

43 Bordoff and O'Sullivan, "The Age of Energy Insecurity."

44 *The Economist*, 26 March 2022.

45 *The Economist*, 18 February 2023, p. 64.

46 *New York Times*, 18 June 2023.

47 *New York Times*, 7 December 2022.

48 *New York Times*, 28 October 2022.

In summary, the two energy problems (security and transition) are not separate "either/or" issues, but inextricably linked. Policymakers must update their approaches and methods to incorporate the new risks stemming from the new, less secure energy environment. "Doing so is not a distraction from addressing climate change but central to it; without this shift, energy crises might derail the drive to net-zero emissions."[49]

2.5 International (Extraterritorial) Mechanisms for Emissions Reduction and Their Potential Impacts on Kazakhstan

The Paris Climate Agreement was signed at the 25th UN Conference of Parties to the United Nations Framework Convention on Climate Change (COP21) in Paris, France on 12 December 2015. Its signatory 196 countries pledged to limit the rise in global mean temperature to well below 2°C above pre-industrial levels through Nationally Determined Contributions to reduce greenhouse gas emissions, and established a system whereby affluent developed countries would provide financial assistance for decarbonization efforts in developing states. An additional, less publicized accomplishment of the Paris Agreement was that it laid out a framework for the development of *extraterritorial* emission reduction schemes or mechanisms. More specifically, Article 6 of the Paris Agreement outlines cooperative "extraterritorial" approaches that countries can pursue to extend the reach of their climate policies beyond their respective national borders. One example of this approach is the EU's Carbon Border Adjustment Mechanism, which went into effect on 16 May 2023.

2.5.1 Carbon Border Adjustment Mechanism

The EU Carbon Border Adjustment Mechanism (CBAM) simultaneously seeks to: (a) encourage countries seeking to export goods to the EU market to adopt the EU's GHG emissions reduction strategies in the production of those goods; (b) protect domestic EU industries from "unfair" competition from imported goods produced without heed for those emissions reduction strategies; and (c) prevent "carbon leakage" from the EU—the re-location of European production to countries with less strict carbon regimes (either as a result of the physical relocation of production capacity outside the EU or by ceding market share to "dirtier" producers as a result of the closure of European capacity). As such, CBAM is the first extraterritorial mechanism that takes into account the carbon emissions embedded into products traded internationally. As the first such framework of its kind, implementation of CBAM will be a complex and challenging task, with its validity and effectiveness being scrutinized by industry representatives, climate activists, government officials, and the international business community. There is also a possibility of legal challenges by major exporting nations at the World Trade Organization (WTO).

In *The National Energy Report 2021*, we were able to examine an initial draft of CBAM issued by the European Commission in July 2021 for the purpose of starting the internal debate among member-states in the lead-up to its formal adoption.[50] Now that CBAM is in force (henceforth, the "extant CBAM") and a pilot phase is scheduled for launch on 1 October 2023, it is useful to review its current provisions and to see how EU views on its functions have evolved since issuance of the 2021 draft. Although the basic scope and functions of CBAM remain broadly the same, some important differences exist. This provides greater clarity into the CBAM scope and implementation timetable, as well as implications for countries seeking to export carbon-intensive goods to the EU market.

2.5.1.1 Scope (emissions and industrial sectors covered)

The greenhouse gases covered under the extant CBAM include those covered in the current EU Emissions Trading System: carbon dioxide (CO_2), perfluorocarbons (PFCs), and nitrous oxide (N_2O).[51] Although in the 2021 draft, only direct emissions (Scope 1)—emissions directly resulting from the production process creating an export good—were included, the extant CBAM now includes "indirect emissions" (Scope 2) in certain industries.[52] Importantly, the sectoral scope of the extant CBAM was expanded compared to the 2021 draft. Although the latter included five industries—electric power, cement, fertilizers, aluminum, and iron-steel—the extant CBAM now adds hydrogen, ammonia, and downstream iron-steel products fabricated from steel. The addition of hydrogen and ammonia undoubtedly stems from a desire of EU policymakers to protect these nascent industries based on wind- and solar-generated electricity from competition from imports utilizing fossil fuels.[53] EU policymakers have built in some capability to further adjust the sectoral scope of CBAM during a pilot phase that will precede the launch of the active (payment) phase of the program (see below).

2.5.1.2 Implementation mechanism and timetable

The initial draft CBAM called for its staged implementation, with a pilot phase (involving only emissions reporting) to begin on 1 January 2023 and entry in full force ("active phase") on 1 January 2026. The extant CBAM generally follows this general timetable, only with a lag of several months, with the pilot phase launching on 1 October 2023. During the active phase, exporters to the EU will receive a free allowance of "CBAM certificates" (GHG emissions allowances, each equivalent to 1 ton of CO_2e) valid for one year. Exporters of goods with above-allowance emissions for a product will be required to purchase additional certificates to compensate.[54] Exporters will be able to receive credits/compensation for carbon payments made in their home countries (in the form of a carbon tax or ETS payments).

49 Bordoff and O'Sullivan, "The Age of Energy Insecurity."

50 *The National Energy Report 2021*, pp. 52–54.

51 https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en#sectors--gases-covered. All of these gases are also covered by CBAM, although it appears N_2O emissions would be included only in fertilizer imports.

52 Scope 2 emissions are indirect GHG emissions associated with the purchase and use of electricity, steam, heat, or cooling in the production process at the site of production. The indirect emissions are expected to be covered only for cement and fertilizer imports, on the basis of a methodology to be defined during the pilot phase of the extant CBAM (https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en).

53 *Argus Non-Ferrous Metals,* 13 December 2021, p. 25.

Emissions reporting and accounting/compensation will occur annually and follow the same procedures as in the 2021 draft. Exporters are required to keep detailed records of their emissions for reporting purposes, or to accept "default values" for their emissions, based on the 10% of EU companies in the same industry reporting the highest emissions per unit of output.

During the active phase the share of free allowances will gradually diminish, so that certificate purchases will increase progressively: initially, importers will be required to buy certificates for 2.5% of their emissions (2026), rising to 100% by 2034.[55] This timetable for gradual reduction in free allowances is aligned with the phase-out of similar free GHG emissions allowances in the EU Emissions Trading System (ETS) and full phase-out (2034) occurs some two years earlier in the extant CBAM than envisaged in the 2021 CBAM draft (2036)—another example of energy security concerns accelerating the energy transition.

2.5.1.3 Exemptions

In the 2021 draft, countries whose emissions trading systems are integrated with or otherwise linked to the EU ETS (Iceland, Norway, Lichtenstein, Switzerland, and small offshore territories of the EU) were to be exempt from CBAM. In other cases, further bilateral agreements could be introduced in due course to account for, and deduct, carbon costs in the emissions systems of these nearby trading partners. Presumably, such a mechanism was to be applied to the United Kingdom, whose carbon market closely follows the EU ETS. In the extant CBAM, however, exemptions are only reported to extend to those countries with "an explicit carbon price," leaving considerable space for interpretation.

2.5.1.4 "Watch list" for scope expansion

In the 2021 draft, non-fertilizer chemicals and refined oil products were listed among those industrial products that might be added to the scope of CBAM at some future date. The extant CBAM provides some clarity as to sectors that might be encompassed by the mechanism, and how soon. There is some sentiment in favor of first extending CBAM coverage to byproducts or semi-products (kaolinite, ferroalloys, agglomerated iron ore) in some of the industries already covered, as well as to organic chemicals, with eventual coverage possibly encompassing the entire sectoral range of the EU ETS by 2030.[56] The latter would include a broad range of industries not currently subject to CBAM, including: refined petroleum products, nonferrous metals, ceramics, pulp-paper, organic chemicals, and maritime transport. Yet for now, CBAM is in its very early stages, so its ultimate form remains to be determined.

2.5.1.5 Trade impact for Kazakhstan

In *The National Energy Report 2021* we attempted to gain an approximate perspective on the scale of the impacts of CBAM implementation on Kazakhstan's economy based on a review of exports of goods in categories included in the draft CBAM, based on available foreign trade statistics for Kazakhstan in the immediately preceding years (2018 and 2019). We found then that the immediate effects on Kazakhstan were quite modest: only $193 million of goods exported to Europe (all European countries, not only EU members) were covered by CBAM, less than 1% of the total value of Kazakhstan's exports to the EU ($24.8 billion in 2019). We repeat this exercise for 2023 using the categories listed in the extant CBAM for 2022; again, the effect on Kazakhstan would appear to be manageable: only $2.5 billion of these CBAM-related goods were exported to all countries in 2022 (not just EU members), representing only about 3% of the total value of Kazakhstan's overall exports. Furthermore, the bulk of these goods were exported to neighboring countries, with very little going to the EU.

2.5.2 Other extraterritorial emissions reduction mechanisms

Although CBAM is the first extraterritorial mechanism of emissions reduction that takes into account the carbon emissions embedded into products traded internationally, it likely will not be the only one. International trade is viewed as a key lever in extending the reach of climate policies to other states outside the national borders. As a consequence, climate policies are increasingly coming into tension with the post–World War II global trade system geared towards the removal of trade barriers under the auspices of the WTO and related bodies. This system led to expanded trade based on comparative advantage and resulting costs of production; it did not take into account the environmental costs of mitigating GHG emissions.

Now, in the present environment of increased geopolitical uncertainties, climate concerns (sometimes merged with those centered on national security) are leading to the enactment of new national industrial and trade policies: (a) incentivizing the development of nascent clean-energy technologies and industries (e.g., tax incentives and subsidies for electric vehicles, batteries, and clean-energy minerals provided in the US Inflation Reduction Act of 2022); and (b) tariffs on imports, either to penalize producers of goods for high GHG emissions, to protect new domestic industries from competition, or both (CBAM). These new trade and industrial policies have tended to enjoy considerable domestic political support, appealing both to those advocating more aggressive climate action and to those in favor of protecting jobs and industries from perceived external threats (e.g., competition from China in the case of the United States).

The **Global Arrangement on Sustainable Steel and Aluminum** (henceforth GASSA), now being negotiated, is the first specific initiative after CBAM in which a group of countries (in this case, the United States, the EU, and possibly similar like-minded countries such as the United Kingdom and Japan) are proposing to enact tariffs on imports of steel, aluminum, and their products from countries in which production of these commodities results in GHG emissions above a certain threshold. The United States and EU have been holding talks on the proposed agreement since 2021, and recent reports indicate sufficient progress has been made so that a final decision is expected by October 2023.[57] Although formulation of a methodology to measure the carbon footprint of these industries

54 To facilitate the description, the text is worded in such a way that the exporter is described as incurring the costs of compliance, whereas in actuality, the actual payment will be made (in one way or another) by the party in the EU that arranges for the imports of the goods.

55 S&P Global Regional Integrated Insight, *CBAM: Europe agrees carbon tax for importers of selected products,* 16 January 2023.

56 *Argus Non-Ferrous Metals,* 13 December 2021, p. 25.

initially was reported to pose a challenge, it appears that CBAM methods to measure compliance of these industries, now in place, offer a template to move forward. GASSA envisions a tiered system of tariffs. More specifically, GASSA members, who must document compliance with the agreement's emissions standards, will pay no tariffs; steel and aluminum imports from other countries will be subject to a rising scale depending upon their emissions. Similar to CBAM, GASSA emissions standards are intended to become more rigorous over time, to incentivize continued progress in emissions reduction.

In the current geopolitical environment, more such industry-specific climate and trade agreements among like-minded states are possible, given the current lack of momentum for more comprehensive (both geographically and sectorally) international trade pacts. If agreements between the US and EU can be forged for aluminum and steel, for example, it does not seem implausible that future talks could be devoted to other widely traded commodities under CBAM coverage (e.g., cement, fertilizers, or hydrogen).

2.6 How Much Will the Energy Transition Cost?

One of the most important questions from a national (energy) security perspective involves the overall cost of the energy transition and its potential impacts on economic performance, jobs wages, and vulnerable populations. Anxiety about the cost of the transition is a genuine concern and perhaps the single biggest obstacle to achieving political consensus on the implementation of a net-zero carbon strategy. This is a very complex issue; it is difficult, if not impossible, to provide answers with a high degree of precision or specificity. However, S&P Global analysts have attempted to address this question for a selected country, the United States, and a collaborative effort by German and Kazakh analysts have carried out a similar analysis for Kazakhstan.[58] Their findings at least shed some light on broad cost parameters of the pathway to net-zero and help in identifying groups and sectors that will be most heavily impacted. It should be emphasized from the outset that the costs cited here are based on hypothetical net-zero projections based on particular pathways; these are not the most likely future outcomes. Few if any countries in the world are presently on track to achieve their net zero pledges, and the goal of limiting global warming to 1.5°C above pre-industrial levels is now viewed by many as already out of reach.

2.6.1 Estimated costs for the United States

The US analysis utilizes a proprietary S&P Global Fast Transition® scenario that incorporates as its basic inputs the changes in energy production and consumption that would be necessary for the United States to achieve net-zero carbon emissions by 2050, and calculates three basic cost components:

- direct energy expenditures by consumers
- related societal costs borne by the population, including:
    - direct costs for electric vehicle and heat pump purchases as well as tax payments by citizens to support clean-energy subsidies and incentives
    - direct costs associated with the retraining of displaced workers in the fossil fuel industry
    - indirect costs associated with carbon mitigation
- corporate clean-energy infrastructure investment, primarily in the electric power grid.

2.6.1.1 Direct consumer expenditures on energy increase under net-zero, but only modestly for the US

An important assumption underlying the Fast Transition scenario is that the current situation of heightened energy price volatility in 2022 and 2023 does not represent the "normal" situation. When considered as the "total bill" realized by end-use customers, in 2023 all US energy consumers are expected to spend around $1.7 trillion for energy in all its various end-uses, such as electricity for homes and business, natural gas used for space heating and industrial processes as well as oil for transportation and industrial feedstocks.[59] This is a sharp increase compared with recent historical values of $1.1 trillion–$1.4 trillion. As a consequence, the Fast Transition scenario projects direct consumer expenditures to recede from current elevated levels to about $1.3 trillion (in real terms) by 2026, which it uses as a more normal base year for comparison with 2050.

In the Fast Transition scenario, *final* energy demand from end-users declines nearly 30% by 2050 while its composition changes dramatically. The single biggest driver of this decline is the transportation sector's conversion from internal combustion engines to battery electric and fuel cell electric drive trains, which are much more efficient at the point of end use.[60] More specifically, electricity consumption grows by 67% and constitutes 42% of 2050 final energy consumption. Natural gas use declines 34% but still plays a significant role in 2050, providing 26% of final energy consumption. Oil consumption declines 87% and accounts for only 8% of 2050 final energy use, mostly in specialized uses and as feedstock. Hydrogen grows from a negligible energy end use today to 10% of 2050's final energy consumption.

57 *New York Times*, 4 October 2021, 8 December 2022, 11 March 2023.

58 The discussion in this section of the Report is based on, for the United States, S&P Global, Global Power and Renewables, Executive Briefings *US Energy: Costs of achieving a net-zero transition across the US economy*, 13 June 2023. For Kazakhstan, the basic document reviewed is DIW Econ GmbH and Astana office of the German Society for International Cooperation (in collaboration with Germany's Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety), *Kazakhstan: Towards Net Zero by 2060—Long-Term Low Greenhouse Gas Emissions Development Strategy (LEDS) of Kazakhstan*, 19 September 2021.

59 In this characterization of energy costs, residential/commercial, industrial, and transportation sector expenses measure the cost of fuel consumed at the end-use level. End-use electricity cost is a single value aggregated across all sectors. Considering its size, economy-wide energy expense in the United States is significant yet modest compared to overall economic activity, amounting to about 6–7% of US GDP.

60 To a large extent, this decline is an artifact of energy accounting, as many energy efficiency losses are shifted upstream of final uses. As a result, primary energy demand declines by only about 7% through 2050.

The cost savings resulting from the reduction in final energy demand, however, is offset by the transition from relatively cheaper fuels such as coal and natural gas to relatively more expensive energy sources such as electricity and hydrogen. Consequently, beginning from the comparison base year of 2026, all consumer retail energy expenditures grow slowly (in real terms) from about $1.3 trillion annually in the 2020s to $1.4 trillion–$1.5 trillion in the 2040s, an increase of 8-15%. Direct energy expenditure by consumers is by far the largest cost category affected by the transition.

Changes in overall sector expenditures vary widely. While *power expenditures* increase by 72% over the 2026–50 period, mostly due to increasing sales volumes arising from electrification, *transportation* expenditures decline by about 27%, reflecting the longer-term electrification trend. The replacement of gasoline and diesel with hydrogen and biofuels keeps transportation expenses from declining more. Residential/commercial expenditures are projected to decline about 17% owing to increased efficiencies resulting from electrification. Conversely, measured from 2026, *industrial* energy expenditures increase about 21%, mostly owing to the replacement of natural gas and coal with hydrogen.

It is important to keep in mind that backward-looking projections of direct energy expenditures historically (i.e., over the past two decades) have tended to overstate costs. A recent survey of the large energy models used to inform influential reports issued by the Intergovernmental Panel on Climate Change (IPCC) found that these models systematically overestimated the actual future costs of key green energy technologies.[61] Retrospective analysis revealed that these models built in overly conservative assumptions on renewable energy floor costs, deployment rates and technology mix—failing to fully capture the rapid cost reductions (economies of scale and vertical integration) that historically have accompanied increased adoption and production of green technologies; i.e., the more than 90% decline to date in the cost of wind and solar power and batteries since commercial production in the 1980s–1990s. In contrast, so-called "experience curve models" that incorporate steady cost reductions as adoption increases generally yield more optimistic (lower) cost forecasts, but do seem to offer better predictive power for the historical period.

2.6.1.2 Direct and indirect societal costs are offsetting

Societal costs in the S&P Global study of the US energy transition include both direct and indirect costs. Among the direct societal costs, in the overall scenario consumer investment costs increase to $44 billion annually in 2050, peaking at $174 billion in 2036, driven by the net purchase cost of clean electric vehicles (CEVs) after CEV incentives expire in 2035. Other direct societal costs (i.e., the cost to taxpayers of government incentives and offsets) increase to $179 billion annually in 2050, peaking at $233 billion in 2040 (Figure 2.2 Societal cost of energy, other than retail energy costs).

Among these other direct societal costs are the costs of retraining and relocating workers in the fossil fuel industry (e.g., in coal mining, oil and gas extraction, oil refineries, and power plants) displaced by the transition to cleaner forms of energy. In the United States at present, there are 900,000 such workers, and it is not clear how easily the bulk of them could be retrained and re-employed in new clean-energy jobs. The Inflation Reduction Act seeks to anticipate this problem by setting aside $4 billion in tax credits for clean-energy companies to invest in new projects in "energy communities"—towns in regions of coal and oil and gas extraction that are impacted by fossil fuel site closures.[62] The effectiveness of the program will need to be monitored, as it is not clear whether the incentives will be adequate to induce companies to invest in such communities vis-à-vis other sites more proximal to centers of large and growing power demand.

Offsetting the increase in direct societal costs, indirect costs (i.e., externalities based on the environmental cost of carbon) decline from $308 billion in 2023 to zero in 2050. These indirect costs or carbon externalities, also known as the "social costs of carbon," encompass the costs of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and wildfire natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. While there still are carbon emissions in 2050, they have been counterbalanced by purchases of carbon offsets at a cost of about $66 billion. Therefore, the view on trends in the energy transition's total societal costs depends on whether to include carbon externalities as valid societal costs. When excluding consideration of carbon externalities, the societal cost of energy in 2050 is expected to be 17% higher than in 2026; but when carbon externalities are included as a societal cost, society's total energy cost in 2050 is 3% less than in 2026. Thus, regardless of perspective and considering that consumers will be shifting to higher-priced energy sources, the energy transition, if implemented in a manner like the Fast Transition case, does not appear to drive total costs of energy to prohibitive levels.

2.6.1.3 A net-zero power sector requires substantial additional electric power investment expenditure

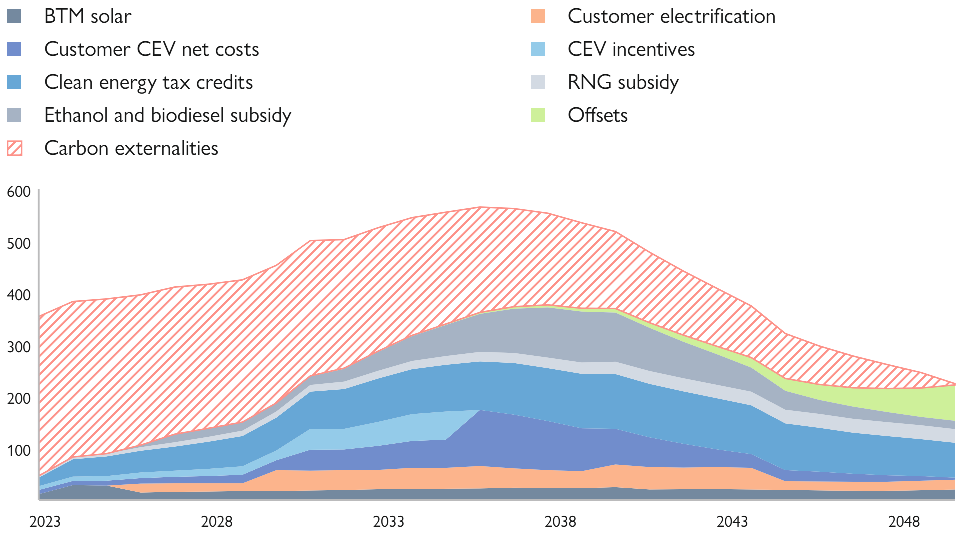
Power sector infrastructure capex in the United States over the period 2023–50 amounts to about $7.1 trillion in Fast Transition, 85% higher than the $3.7 trillion estimated for the S&P Global Planning Case® ("business as usual"). Significantly higher investment levels are expected for both the transmission grid and grid-connected generation. Wind and solar account for over 70% of total generation capital expenditure over the period, and batteries account for another 14%.[63] When annualized, the additional electric power investment required under a 2050 net-zero scenario (compared to business as usual) would amount to approximately $90 billion per year.

61 For instance, a model used by the IEA in 2010 to project the cost of solar energy in 2020 estimated a cost of $260 per megawatt-hour (MWh), whereas the actual cost in 2020 turned out to be $50/MWh. For details, see R. Way, M. Ives, P. Mealy, and J.D. Farmer, "Empirically Grounded Technology Forecasts and the Energy Transition," *Joule*, Vol. 6, No. 9, 2022, pp. 2057–2082; see also R. Way, "Modeling a Greener Future," *The American Scientist*, Vol. 111, No. 4, July–August 2023, pp. 208–210.

62 In addition to the credits, the IRA also makes available loans for companies to repurpose shuttered fossil fuel sites as clean-energy projects (*New York Times*, 12 July 2023).

63 Increases in distribution investments are tempered by Fast Transition's decarbonization approach, which minimizes the impact of electrification on the distribution grid peak demand and instead assumes the final decarbonization tranche comes from offsets. Full end-use electrification would entail much higher distribution costs.

Figure 2.2 Societal cost of energy, other than retail energy costs (billion 2021 $)



Notes: RNG = renewable natural gas, CEV = clean electric vehicles, BTM = behind-the-meter.
Source: S&P Global Commodity Insights.

2.6.2 Estimated costs for Kazakhstan to reach net zero

The applicability of a scenario projecting potential US costs of attaining net-zero emissions to the situation in Kazakhstan has obvious limitations. The structure of economic activity and energy consumption in the two countries is quite different. In the United States, the transportation sector (37%) dominates the structure of final energy demand, followed by industry (35%), the residential sector (16%), and commercial uses (12%). In Kazakhstan, in contrast, the residential (33%) and industrial (32%) sectors dominate, with transportation having a much smaller role (18%), followed by the commercial sector (16%).[64] The fuel mix in primary energy demand also varies, with oil (38% of total demand) and gas (32%) dominating in the United States, while it is coal (50%), oil (18%), and gas (28%) being most widely consumed in Kazakhstan.[65] The energy sector is the largest source of GHG emissions in Kazakhstan. At present, about 80% of all annual GHG emissions in Kazakhstan is generated in the energy sector. And within energy, electric power generation alone accounted for nearly half (46%) of Kazakhstan's total GHG emissions in 2022; 87% of these power-sector emissions come from coal-fired plants. Consequently, a fuel switch from coal to natural gas or renewables in electric power generation would result in significant reductions in Kazakhstan's energy-sector GHG emissions, although these would be offset to some degree by increasing emissions from the transportation of gas to power plant sites. Another factor affecting the costs of reaching net zero for Kazakhstan (vis-à-vis the United States) is the lack of domestic capacity for manufacturing renewable energy equipment (e.g., turbine nacelles, solar panels) in Kazakhstan, which necessitates more costly imports.

A partial accounting of the costs to Kazakhstan of achieving net-zero emissions was undertaken in a joint 2021 study involving German and Kazakh researchers.[66] Its basic findings are similar to the S&P Global analysis for the United States, concluding:

- A future with net-zero GHG emissions by 2060 in Kazakhstan is both technically possible and economically feasible.
- However, achieving this goal will require deep structural changes throughout the entire economy—from power generation and industry, to buildings and the transport sector, to agriculture and land use. It also includes a thorough and fundamental transformation of the energy sector in particular:
  - Gas will account for nearly 15% of total primary energy production in 2060 (down only slightly from 16% in 2022), and oil for about the same share (but down from 47% in 2022). These shares will be significantly less than wind or solar resources (72% in aggregate, up exponentially from 1.5% in 2022). Coal will be nearly non-existent (less than 0.1% total primary energy production, compared to nearly 36% in 2022).
- Carbon neutrality will require the mobilization of substantial investments over the entire period to 2060, although for most of the time in aggregate it does not exceed historic investment to GDP ratios for Kazakhstan.

The Kazakh-German study does not break down the costs of net zero into the same categories as the S&P Global study for the

64 US final demand statistics are for 2021(https://www.eia.gov/energyexplained/us-energy-facts/images/consumption-by source-and-sector.pdf); Kazakhstan's statistics are for 2022.
65 *BP Statistical Review of World Energy 2022*, p. 9.
66 *Kazakhstan: Towards Net Zero by 2060*, pp. 40-41.

US—direct consumer expenditures on energy, direct and indirect societal costs, and power system upgrading along with expansion investments. Nor does it utilize the same decarbonization timetable (using 2060 as an end-date rather than 2050). However, it does provide an estimate of at least how much net incremental (additional) investment in power-sector and other clean-energy technologies is required over the four-decade period 2021-60: a massive $666.5 billion, or roughly triple Kazakhstan's 2022 total nominal GDP of $223.5 billion in 2022. This amounts to an annual average of just over $17 billion, compared with $30-32 billion annually in recent years for total investment in the economy or about $8 billion in oil and gas extraction or about $1.9 billion annually in electric power.

Presumably this estimated investment figure would significantly overlap with the societal costs and electrification investment categories used in the US study, by encompassing investments in energy infrastructure by the Kazakh government and companies and purchases by Kazakh consumers of EVs, home solar panels, energy-efficiency appliances, etc. But it presumably would not include other direct societal costs, such as the burden on taxpayers of clean-energy subsidies and tax incentives, the costs of worker retraining and relocation, and the need to provide financial support to vulnerable social groups via targeted subsidies. Nonetheless, an expected reduction of 9,335 $MMtCO_2e$ of GHG emissions over the scenario period is expected to yield a substantial savings in indirect societal costs (of GHG emissions on public health, economic productivity, etc.), which the study estimates will reduce the overall decarbonization price to a relatively low $71.5 per ton of CO_2e.[67]

In the most intensive early investment phase until 2030, the investment share in GDP is projected to reach 34%, which is slightly above the average for World Bank–designated upper-middle-income countries as well as peak investment levels in Kazakhstan in 2008-14. But after 2030, the investment share of GDP declines and, by 2050, begins to approach the pre-pandemic level of 2019.[68] According to the authors, it is important to keep in mind that much of the investment in zero- or low-carbon technologies would eventually be needed in any event, to retire aging (high-carbon) capital assets that have exceeded their useful lifetimes. Almost the entire capital stock in power and heat generation would need to be replaced over the next four decades to 2060.[69] In both Kazakhstan and the United States, the direction of the transition points to greater electrification—in the United States, a movement from gasoline and diesel fuels toward electric traction and the related charging and manufacturing infrastructure, and in Kazakhstan increased electrification and energy efficiency in buildings and cleaner fuels overall.

The financing of decarbonization investments in Kazakhstan through higher consumer direct expenditures on energy is challenging economically (and fraught politically), because current regulations ensuring low consumer tariffs for electricity, heat, and fossil fuels provide inadequate resources for upgrading networks and switching to more sustainable generation sources. Therefore, in order to decarbonize the power and heat sector, the introduction of market prices for energy services will be necessary, in order both to create the revenues needed for upgrading and to stimulate the introduction of energy-saving technologies and changes in consumer behavior. Kazakh energy policymakers are now considering how to distribute energy price hikes across the economy and among the population, while avoiding major disruption for both producers and consumers and mitigating public opposition (for an outline of various support measures that can be utilized to reduce the burden of rising energy prices on the population, see Section 2.9 of this chapter).

2.7 Energy Company Transition Strategies Have Been Adjusted by Emerging Energy Security Concerns

The response of the business sector to the energy transition has proven complex. For energy producers, many now expect that they will reach maximum oil and gas output earlier and at lower levels than forecasted prior to the pandemic and have pursued portfolio diversification, mergers and acquisitions (M&A), divestments, and new clean-energy ventures to address the energy transition. But energy security concerns stemming from rising prices and disrupted supply chains have caused many industry executives to reassess their business plans and approaches to the transition in general. In *The National Energy Report 2021,* we focused on the strategies employed by three categories of large oil and gas companies—"first movers," traditional international oil companies (IOCs), and national oil companies (NOCs)—to navigate the energy transition.[70] We believe this categorization remains useful in understanding how companies have responded to the new security concerns—not through a fundamental transformation of their approach to the transition but rather through subtle, yet nonetheless substantive, modifications.

Importantly, despite maintaining long-term net-zero plans, most oil and gas companies, particularly the Western supermajors, now intend to either keep growing upstream production deep into this decade or maintain production at higher levels than they had announced only a couple years ago.[71] The apparent contradiction highlights the majors' attempts to meet competing calls for energy security and the low-carbon transition amid the Ukraine war and intensifying global climate crisis. But it also speaks to a potentially uncomfortable reality: While majors' pathways to net zero have always been a bit fuzzy, their primary role as oil and gas producers has never been in doubt — and the group is now realizing that this must remain this way for a considerable time.

2.7.1 First movers

First movers are those IOCs that have embraced the transition, seeking to transform themselves over time from oil and gas producers to broadly diversified energy companies. This group also could be termed the "European majors," as most are

67 *Kazakhstan: Towards Net Zero by 2060,* p. 40.

68 *Kazakhstan: Towards Net Zero by 2060,* pp. 40-41.

69 By far the largest share of the decarbonization investment is needed in power and heat generation, with $305 billion, or 46% of the total investment.

70 *The National Energy Report 2021,* pp. 55–59.

71 "No End in Sight for Oil Majors' Upstream Growth," Energy Intelligence, 26 July 2023.

headquartered there: BP; Shell PLC; TotalEnergies; Galp Energia SGPS, S.A.; and Eni. Equinor, the Norwegian national oil and gas company, also typically is included in this group because its transition strategy closely resembles that of the other first-mover companies. In 2021, we described some key common transition strategies utilized by the first movers (broadly applicable to the group if not in all specific cases):

- Portfolio diversification via downsizing of petroleum assets through divestment or non-replacement of oil and gas reserves
- Reconceptualization of the company mission as providing energy as a service rather than hydrocarbon commodities, with an expansion into renewable electric power generation adding a less volatile (if at times less lucrative) future income stream
- A commitment to emissions reduction, not only that associated with their operations (Scope 1 and 2) but also with the consumption of their products (Scope 3) as a result of conscious plans to curb the growth of their oil and gas output and ultimately to reduce it.[72]
- A plan to use the revenues from oil and gas production to invest in new "green" ventures (renewable power, hydrogen).

The disruption in global energy markets (and resulting price hikes) in 2022 brought record earnings to oil and gas producers, including the first movers. In some ways, Russia's conflict with Ukraine may have accelerated their move away from oil and gas, as BP and Shell (alongside other IOCs such as ExxonMobil) moved to divest major assets they held in Russia. In other cases, hydrocarbon divestitures were planned longer in advance and are consistent with first movers' overall decarbonization plans, such as TotalEnergies' sale of Canadian oil sands assets and Shell's exit from shale oil and gas production in the US Permian Basin in 2021.

But the first movers have selectively continued to invest in the development of oil and gas assets, most notably now in Africa, due to several perceived advantages:

- an Eastern Hemisphere geography viewed as relatively proximal to Europe by sea
- governments favorably disposed toward hydrocarbon development
- greenfield sites that facilitate installation of modern, efficient, and comparatively "clean" extraction infrastructure.

Examples of this "turn to the south" include recent deals by Eni to develop natural gas in Libya, by Shell and Equinor to develop LNG in Tanzania, and by TotalEnergies to develop projects in Mozambique (LNG) and Nigeria (offshore oil and gas).[73]

Yet clean energy is supposed to be a larger focus of new investments, which is expected to account for as much as half of capex by the European majors by 2030. Shell is now producing renewable electricity in nine countries (including Australia, India, and the United States), with plans to double generation by 2030. It is also involved in a partnership with a Chinese company to develop EV charging stations in Asia and Europe.[74] BP and Eni have major investments in green hydrogen projects in Mauritania and Algeria, respectively; and Eni is currently building a small solar power plant in Kazakhstan's Turkestan Oblast, after earlier completing two wind farms of 96 MW in Aktobe Oblast.[75] And in South Africa, TotalEnergies has an interest in the Prieska solar power plant, which supplies electricity to over 70,000 households, and participates in several projects to construct other solar power plants. It also markets solar panels in that country, and recently purchased a 50% stake in Clearway Energy, a US wind and solar power company, for $2.4 billion. And in June 2023, TotalEnergies signed a 25-year agreement to purchase electric power generated from the 1 GW Mirny wind farm in Zhambyl Oblast, Kazakhstan's largest.[76]

Yet the most publicized events involving the first movers represent what many clean-energy advocates view as a setback. On 7 February 2023, BP announced that it was scaling back its Scope 3 emissions reduction pledge; it had originally committed to a 35–40% emissions cut by 2030, but reduced this to 20–30%, citing the need to accommodate near-term energy security concerns: "to make sure that rapid transition is balanced and orderly, so that affordable energy keeps flowing where it's needed today."[77] To support this commitment to produce more oil and gas than originally planned over the medium term, BP announced it would increase capex by $1 billion annually, both for oil and gas production as well as in its transition businesses (e.g., biofuels, EV charging infrastructure, renewable power) and retreat from more ambitious plans to shrink its reserve base through divestitures and depreciation. As a consequence, BP envisions its 2030 crude oil output will be 25% less in 2030 (2 MMb/d) than at present, rather than 40% less, as originally planned.[78]

The move probably should be viewed more as a minor strategic adjustment than a wholesale revision of company strategy. The scaled-back oil production reduction target moves BP closer to those of fellow first movers Shell and TotalEnergies, which have both stated an intention to keep production broadly flat through the decade. And even despite the scaled-back emissions reduction target, which is now less ambitious than those of Shell and TotalEnergies (50% and 40% reductions, respectively, by 2030), S&P Global forecasts that BP will still have the lowest GHG emissions in absolute terms among the five global "supermajor" oil and gas companies.[79]

Echoing BP's strategic deceleration of its decarbonization goals, at Shell's Investor Day held in New York on 14 June 2023, CEO Wael Sawan announced plans to keep the company's oil and gas production steady at current levels (1.4 MMb/d) though 2030, instead of allowing it to fall by 1–2% per year under a previous plan. Citing a "ruthless" focus on financial performance, he stated

72 Scope 3 emissions are those from activities or assets not owned or controlled by a company but result from the use of its products.

73 *The Economist*, 11 February 2023, pp. 57–58.

74 *New York Times*, 8 June 2022.

75 Energy Intelligence, *Nefte Compass*, 21 June 2023.

76 The $1.4 billion project is being developed by a multinational consortium that includes TotalEnergies (40% shareholding), KMG (20%), and Kazakhstan's Samruk-Kazyna National Fund (20%). Construction is slated to begin in late 2023 and completion is expected in late 2024 (Energy Intelligence, *Nefte Compass*, 21 June 2023).

77 https://www.bp.com/en/global/corporate/sustainability/getting-to-net-zero.html.

78 For details, see Energy Intelligence, "BP Walks Back Aggressive Transition Approach," 7 February 2013. https://www.energyintel.com/00000186-2ce5-d0a2-a3e7-3ef5126f0000#:~:text=BP%20is%20shifting%20its%20strategy , a%20medium%2Dterm%20energy%20shortage .
S&P Global Commodity Insights, Corporate Emissions Solution, *BP Scales Back Emissions Reduction Goals amid Record Profits: Corporate Emissions Solutions data for oil and gas companies analyzed*, 22 May 2023.

79 BP, Chevron, ExxonMobil, Shell, and TotalEnergies.

that "[i]t is critical that we avoid dismantling the current energy system faster than we are able to build the clean energy system of the future."[80] The company's total capex in 2024–25 will be reduced by 5–6% from previously planned levels, while returns to shareholders will be increased to 30–40% of cash flow from 20–30% previously. Environmental activists decried the move as a "stealth" pivot from low-carbon energy.

2.7.2 Traditional IOCs

The traditional IOCs are large integrated oil companies that have tended (for the time being) to retain their traditional focus on upstream production. While not completely ignoring the energy transition, they adopted a more cautious, "wait-and-see" approach. This group could also be labeled the "North American majors," as most are headquartered in either the United States or Canada. Primarily consisting of the US majors ExxonMobil and Chevron, it also includes somewhat smaller companies such as Canadian oil producers Cenovus, Suncor, and Imperial Oil. In 2021, these traditional IOCs employed strategies focused on:

- ***Continuing to develop core hydrocarbon assets*** (concentrated portfolios)—relatively lower-cost barrels in known geological environments near home (North American) markets, in stable geopolitical environments with existing infrastructure (e.g., Permian Basin, Gulf of Mexico)
- ***Maintaining capital discipline***—limiting capex and operating ***costs through efficiency improvements, including*** digitalization (reduced labor costs in drilling and equipment monitoring; improved geologic data analysis, project design, seismic modeling, and field development)
- ***Targeting emissions reduction efforts on their own operations*** (Scope 1 and 2 emissions), and generally avoiding any pledges for Scope 3 emission reductions; this includes an emphasis on such activities as increasing use of associated gas, reducing methane leakage and flaring, and limiting new clean-energy initiatives to areas in which they have existing expertise; e.g., carbon, capture, utilization and storage (CCUS), biofuels, and blue hydrogen.[81]

The activities of the traditional IOCs in 2022–23 have generally remained consistent with their priorities in 2021. The portfolio concentration efforts of these companies exhibit a pattern of divestment and new investment not that different from the first movers, although reflecting different causes and involving different assets. ExxonMobil and Chevron have exited assets in Europe, Africa, and Southeast Asia that are distant from their home jurisdictions, while focusing new investment within the United States and friendly Western Hemisphere geographies, such as Guyana. More specifically, ExxonMobil departed Russia, where it operated the Sakhalin-1 oil and gas project on behalf of a multinational consortium, in 2022, and the company also has now sold (or is in the process of selling) assets in Cameroon, Chad, Equatorial Guinea, and Nigeria. Chevron, similarly, has sold projects in the UK and Denmark and has not renewed expiring concessions in Indonesia and Thailand.[82] Chevron is now reportedly in the process of seeking buyers for assets it holds offshore Congo and Angola.[83]

The targets of new investment have been the United States (onshore and offshore) and South America. ExxonMobil has invested heavily in the Permian Basin, which accounted for half of its US oil and gas production in 2022 and where company production is slated to reach 1 MMb/d by 2027, and in greenfield oil and gas development in offshore Guyana. Favorable development terms in the latter country, which had no previous history as an oil producer, enabled Exxon to move from deepwater discovery (2015) to first production (2019) in less than half a decade. Over 25 significant petroleum discoveries have now been registered. Chevron, similarly, has concentrated new investment in the Permian Basin and related shale assets (a projected 30% of 2023 capex) and offshore Gulf of Mexico (20%). On 22 May 2023, Chevron expanded its shale holdings by acquiring shale producer PDC Energy, with assets adjacent to existing Chevron properties in the Denver-Julesburg and Permian basins.[84] Chevron's investments in the offshore Gulf of Mexico are devoted to advancing projects such as its operated Ballymore tieback, the Anchor hub development, and the St. Malo Stage 4 waterflood scheme. The company's signature project to develop the Jack and St. Malo fields is expected to yield more than 500 million oil-equivalent barrels over the project lifetime.

Reflecting the strengthened commitment to capital discipline, E&P budgets for 2023—$23–25 billion for ExxonMobil, $17 billion for Chevron— are greater than for 2022, but smaller than what was projected prior to the COVID-19 pandemic. Clean-energy spending as a share of overall capital spending by the traditional IOCs is much lower than for the first movers. ExxonMobil, for example, plans to spend $17 billion on low-carbon activities in 2022–27, up from previous targets of $15 billion and compared with the $10 billion invested during 2000–20. However, S&P Global estimates that low-carbon spending by the company only amounts to 4% of total corporate spending in 2022, rising to 18% by 2027.[85] This is considerably lower than the average low-carbon spending of a "peer group" of seven IOCs (BP, Chevron, Eni, Equinor, ExxonMobil, Shell, and TotalEnergies), of 12% and 25% for 2022 and 2027, respectively. Similarly, Chevron has budgeted only 8% of total corporate spending for low-carbon investments by 2025.[86] Unlike the renewable power–focused clean-energy spending undertaken by the first movers, most low-carbon spending by ExxonMobil and Chevron is focused on lowering emissions in their own operations and leveraging existing competencies—CCUS, blue hydrogen, and biofuels (see Figure 2.3 Global integrated oil companies: Current low-carbon strategies).

2.7.3 NOCs

The national oil companies' approach to the energy transition is strongly influenced by their role as stewards of their respective countries' national hydrocarbon wealth. With substantial state ownership, they operate as agents of state policy and are less

80 https://www.ft.com/content/a5d7b2e5-fe13-481d-88a4-de9e66171fad; https://www.reuters.com/business/energy/shell-boost-dividend-cut-spending-new-ceo-plan-2023-06-14/.

81 ExxonMobil, Chevron, and Imperial all have net-zero pledges for Scope 1 and 2 emissions by 2050. The first movers made similar net-zero Scope 1 and 2 pledges. BP, Eni, and Galp pledged net-zero Scope 3 emissions by 2050, while TotalEnergies targeted a 40% reduction in Scope 3 emissions by 2030.

82 *The Economist,* 11 February 2023, pp. 57–58.

83 S&P Global Commodity Insights, Companies & Transactions, *SEAM Alert—Upstream: Chevron rumored to divest Republic of Congo and Angola/Congo unitized area assets,* 23 June 2023.

84 https://www.reuters.com/markets/deals/chevron-buy-pdc-energy-76-billion-2023-05-22/.

85 S&P Global Commodity Insights, *Low-Carbon Company Profile: ExxonMobil,* May 2023.

86 S&P Global Commodity Insights, *Low-Carbon Company Profile: Chevron,* September 2022.

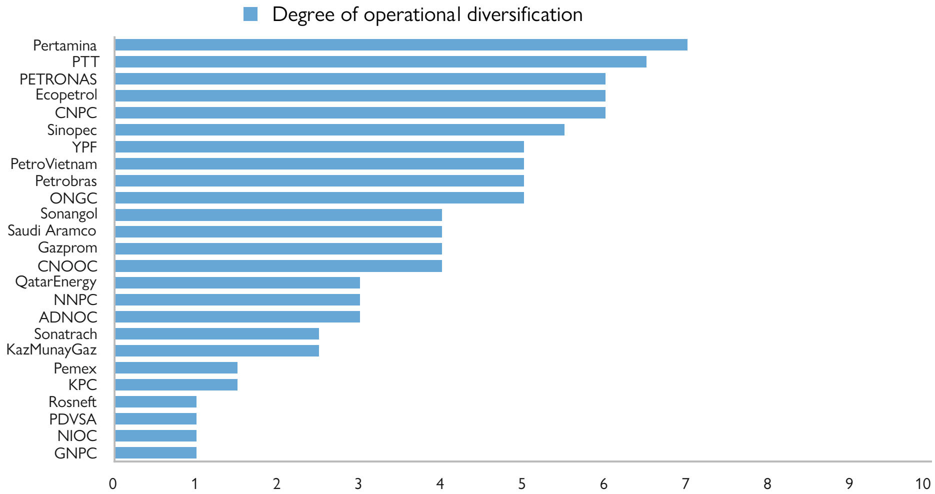
Figure 2.3 Global integrated oil companies: Current low-carbon strategies

		BP	Chevron	ENI	Equinor	ExxonMobil	Repsol	Shell	TotalEnergies
Emissions targets	Net-zero Scope 1 and 2 emissions	▲	▲	▲	▲	▲	▲	▲	▲
	Net-zero Scope 3/life-cycle emissions	▲		▲	▲		▲	▲	▲
	Reduce flaring and methane emissions	▲	▲	▲	▲	▲	▲	▲	▲
Low-carbon energy	Integrated gas	●	○	●		○	◌	●	●
	Solar generation	●		●	○		●	○	●
	Onshore wind generation	○		●	○		●	○	●
	Offshore wind generation	●	◌	●	●		○	●	●
	Low-carbon power transmission/distribution	◌		●			●	●	○
	Bioenergy	●	●	●	◌	●	●	●	●
	Hydrogen	●	●	○	●	●	●	●	○
Mobility and other	EV charging infrastructure	●		●			○	●	○
	Batteries (storage)	◌		◌	○		◌	○	○
Emissions management	Carbon capture, utilization and storage	○	●	◌	●	●	◌	●	●
	Nature-based solutions	○	○	◌	◌		◌	○	○

▲ Target established
● Primary area of focus
○ Other area in development/operation
◌ Early indication of interest

Source: S&P GlobalCommodity Insights.

Figure 2.4 NOCs: Operational diversification



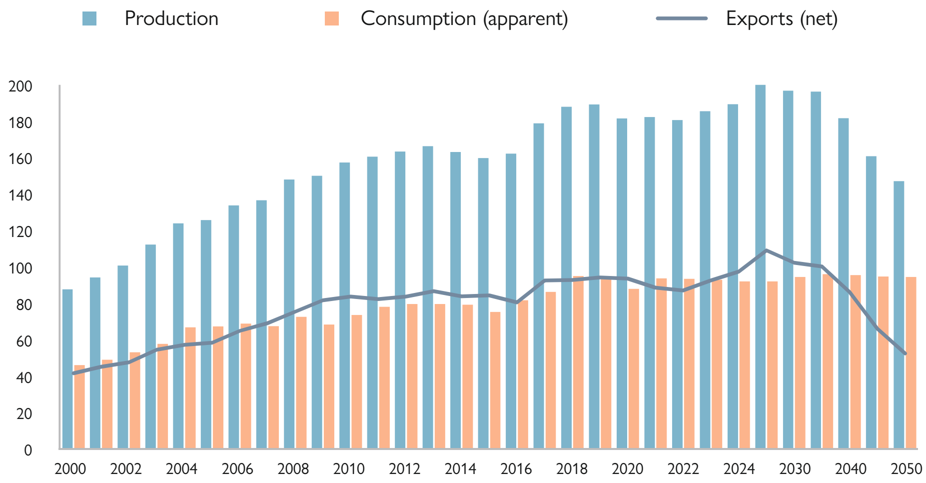
Notes: For ranking,1 is low, 10 is high.
Source: S&P Global Commodity Insights.

directly responsive to shareholder or even stakeholder concerns. They include true supergiants such as Saudi Aramco—the world's largest integrated oil and gas company—as well as a host of other companies arrayed across the size scale. S&P Global routinely tracks a group of 25 NOCs that are listed in Figure 2.4 NOCs: Operational diversification.[87] Although the companies in this group have adopted vastly different transition strategies, there are several common themes and approaches:

- To the extent possible, fully *monetize the national petroleum resource* for the well-being of the state and its population, in order to:
  - finance social programs
  - fund future energy investment, including clean energy
  - provide employment
- In countries with limited petroleum reserves compared to domestic demand (e.g., China and Southeast Asia), the NOC mandate additionally may include acting on behalf of the state to *secure hydrocarbon resources abroad to supply the domestic market's energy needs* (so-called "resource-seeking NOCs").
- Be proactive in efforts to *avoid "stranding" the resource* - leaving

87 For details, see S&P Global Commodity Insights, Upstream Companies and Transactions Strategic Report, *NOC Insights—In the race to diversify and decarbonize, most NOCs remain on the starting blocks*, 29 June 2022.

Figure 2.5 Kazakhstan's primary energy balance: historical and outlook to 2050 (MMtoe)



Source: S&P Global Commodity Insights.

it in the ground during episodes of low demand, or permanently when the energy transition is advanced and when demand may fall to near zero; this may mean accelerating production during periods of high prices to maximize the ultimate revenues earned from the resource.[88]

- Follow a "dual approach" of *monetizing the resource while taking initial steps to reduce its carbon footprint* (reducing flaring and methane leakage, increasing own-use of associated gas, and increasing production efficiencies).

In 2022–23, reflecting these priorities, the NOCs as a group allocated less than 5% of their total capex to clean-energy initiatives.[89] Yet the ability of an NOC to diversify its portfolio and invest in non-petroleum (including clean-energy) activities varies widely by country, depending on how much revenue the NOC brings in and the extent to which the national government depends on oil and gas revenues to drive economic growth (Figure 2.4).[90] Among NOCs—and excluding the anomalous Equinor, as mentioned above—PETRONAS is perhaps the most aggressive company pursuing low carbon as a stand-alone business strategy. In 2022, the Malaysian NOC created the Gentari subsidiary, which is targeting 30–40 GW of renewable energy capacity, 1.2 MMt per year of green and blue hydrogen capacity, and about 25,000 charging stations in the Asia Pacific region.[91] Other NOCs, such as Aramco, ADNOC (UAE), CNPC and Sinopec (China), YDP (Argentina), and PTT (Thailand) have made substantial investments in wind or solar power, and still others (ADNOC, QuatarEnergy, and Aramco) in CCUS and hydrogen.

Even those NOCs determined to keep their focus on the petroleum sector (e.g., Venezuela's PDVSA, Nigeria's NNPC, and Mexico's Pemex) are having to adapt as pressure increases to address climate change. NOCs are increasingly redoubling efforts to decarbonize their existing activities, to improve their public image and ensure that they maintain a "social license" as responsible actors to operate in the oil and gas sphere. This includes significant investments to curtail upstream greenhouse gas (GHG) emissions by reducing methane leakage and electrifying field operations, which also can improve operational efficiency.

Finally, for small NOCs with limited financial resources, it is increasingly important to find outside partners—both to fund new clean-energy investments as well as to bolster oil and gas capex to increase their operational capability to monetize domestic petroleum assets within the energy transition timeline. Enabling both types of investment will require the host country to set attractive terms for the participation of foreign partners in upstream development. Kazakhstan's national company KMG already has established a good foundation for foreign investment and cooperation with major international oil companies through its participation in the international consortia developing Kazakhstan's "Big 3" oil and gas mega-projects. The challenge lies in extending these successes to new promising fields (see Chapters 5 and 6).

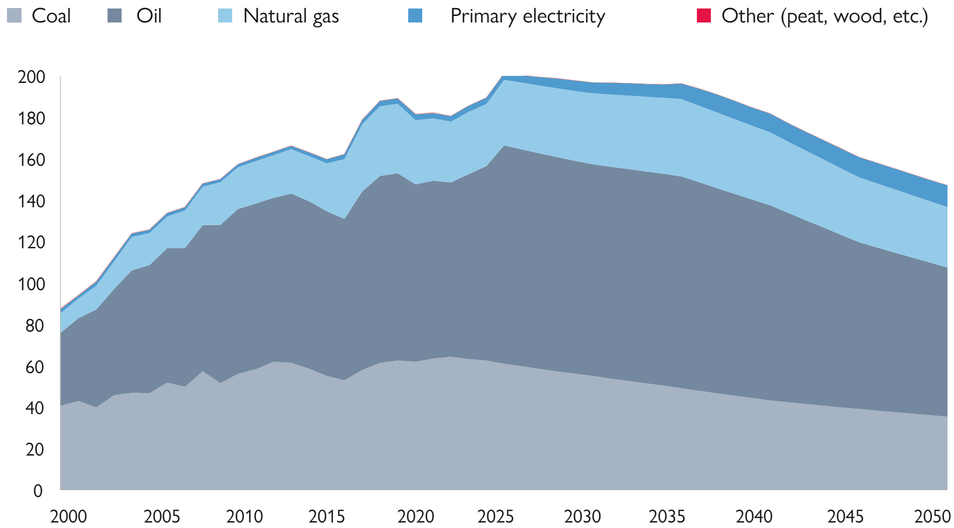
88 This was precisely the plan of action announced by the NOCs of Saudi Arabia, Kuwait, the UAE, Iraq, Libya, Argentina, Colombia, and Brazil during the high price environment that had emerged in late 2021 (*New York Times*, 15 October 2021). And the United Arab Emirates' Abu Dhabi National Oil Company (ADNOC) has announced that it will bring forward its ambitious 5 MMb/d (245 Mt/year) oil production capacity target from 2030 to 2027 to meet what it expects to be rising medium-term global oil demand.

89 *The Economist*, 30 July 2022.

90 The "operational diversification" score depicted in the figure measures the degree to which NOCs have moved to expand their business activities into nonpetroleum spheres in the energy sector: hydrogen, wind power, solar power, biofuels, geothermal, hydropower, other energy infrastructure, and investments outside energy sufficient to constitute a standalone business. NOCs were assigned a binary score (0 or 1) on the basis of their existing research focus, announced business development strategies, and existing investments in the relevant energy segment; a score of 1 indicates an actual committed investment in that energy source, whereas a score of 0 reflects an absence of investment (NOCs with announced plans for investments received a score of 0.5). The aggregate score across all categories then reflects the NOC's "degree of operational diversification" rating (*NOC Insights*, p. 6).

91 S&P Global Commodity Insights, IHS Herold, *Five Key Questions for National Oil Companies in 2023*, January 2023, p. 7.

Figure 2.6 Outlook for Kazakhstan's primary energy production by fuel to 2050 (MMtoe)



Source: S&P Global Commodity Insights.

2.8 Energy Security Outcome: Outlook for Kazakhstan's Primary Energy Balance to 2050

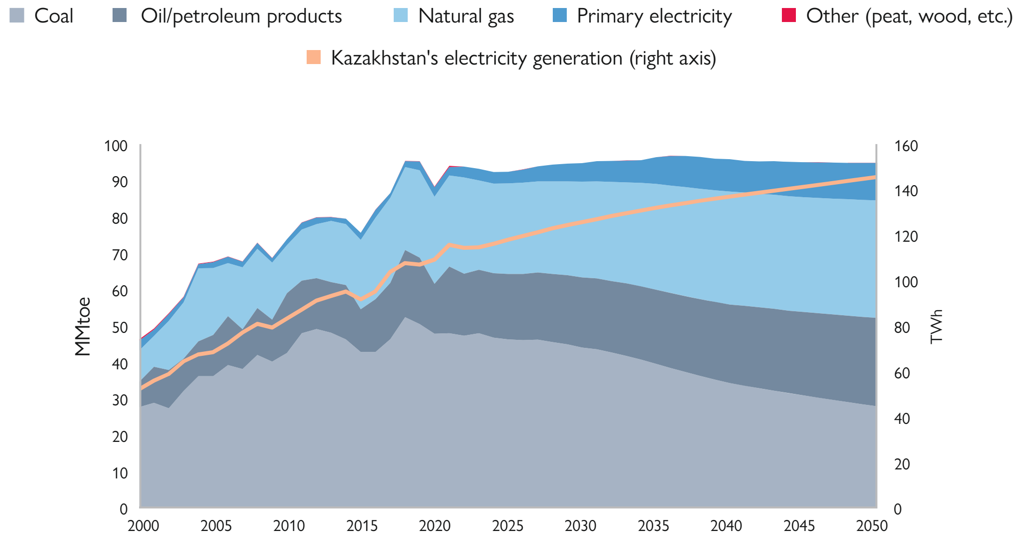
Kazakhstan is expected to remain a net exporter of primary energy (mainly crude oil), but the country's net primary energy exports in 2021 (88.6 MMtoe) and 2022 (87.1 MMtoe) were slightly below immediate pre-pandemic levels (94.2 MMtoe in 2019), reflecting increasing domestic demand as well as slightly lower primary energy production. The main factors were disruptions in production and exports of oil owing to the Russia-Ukraine armed conflict. Total primary energy exports as a share of primary energy production fell from 51.6% in 2020 to 48.6% in 2021, and then to 48.2% in 2022. Our primary energy balance projections show this trend continuing, with the share of production consumed domestically increasing from 51.8% in 2022 to 64.2% in 2050 (see Figure 2.5 Kazakhstan's primary energy balance: historical and outlook to 2050). The implication is that while energy exports will continue to play an important role in the country's economy, slowly declining energy production and rising domestic energy consumption will eventually reduce net primary energy exports substantially, by roughly half (to 52.5 MMtoe) by 2050.

Total production of primary energy in Kazakhstan, which includes oil, gas, coal, and primary electricity (but not mined uranium), fell by 0.9% in 2022 to 180.6 MMtoe. Increases in primary electricity production (i.e., hydro and renewables, by 8.9% to 2.7 MMtoe) and coal (by 1.3% to 64.3 MMtoe) failed to offset declines in oil (-1.9% to 84.2 MMtoe) and gas (-2.6% to 29.4 MMtoe). The 2022 drop in total primary energy production followed a shallow post-pandemic recovery in 2021 (0.4% to 182.3 MMtoe). We expect a return to growth in primary energy production in 2023, by 2.7% to 185.5 MMtoe, led by a rebound in oil and in gas production. Subsequently, primary energy production is expected peak at 200.3 MMtoe in 2026, after which output steadily declines, to 147.1 MMtoe in 2050, representing a net decrease of 26.1% during 2023-50 (an average annual rate of decline of 0.7%). Falling coal output accounts for most of the expected drop in primary energy output during this period (a 2.1% average annual rate of decline, versus a 0.6% annual decline rate for oil) (see Figure 2.6 Outlook for Kazakhstan's primary energy production by fuel to 2050).

Kazakhstan's apparent primary energy consumption remained almost unchanged in 2022 from the previous year, at 93.5 MMtoe. Primary electricity consumption, boosted by the increase in renewable energy, increased by 30.4% (to 3.0 MMtoe), albeit from a small base, and natural gas consumption grew by 5.2% (to 26.4 MMtoe). Longer term, our outlook is for total apparent primary energy demand to remain essentially flat over the 2023-50 period, reflecting further improvements in aggregate energy efficiency that offset the underlying growth in economic activity. But demand trends diverge widely by fuel type: natural gas consumption is expected to grow modestly (by 0.7% annually to 32.3 MMtoe), while we expect demand to grow even more sharply in percentage terms for primary electricity (up 4.5% annually to 10.3 MMtoe); oil demand also remains on a relatively strong growth path (rising by 1.3% annually, to 24.3 MMtoe), while coal consumption falls substantially during the outlook period (dropping by 1.9% annually to 27.6 MMtoe).

A key driver of the changes in the fuel mix to 2050 is the gradual displacement of coal in the power sector, primarily by natural gas along with expansion of renewables and eventually nuclear energy. Aggregate gas consumption growth is muted by efficiency gains, so consumption does not expand as quickly as in the earlier periods. The cumulative change in the share mix of the different energy sources of total primary energy demand (TPED, not including mined uranium) in Kazakhstan is dramatic. Coal, which led all fuels at 50.3% of TPED in 2022, falls to 29.2% in 2050 (as the second-largest energy source). Conversely, gas, which held a 28.3% share of TPED in 2022, grows to become the leading energy source, at 34.8%. But the fastest growing energy source in relative terms is primary electricity (renewables and nuclear), the TPED share of which triples, from 3.2% to 10.9%. Within the primary electricity sector, we believe wind power has exceptional

Figure 2.7 Outlook for Kazakhstan's primary energy consumption by fuel to 2050



Source: S&P Global Commodity Insights; Chemical Market Analytics by OPIS.

potential for growth during the outlook period; electricity generated by wind stations almost matches hydroelectricity generation at the end of the outlook period, reaching 18.6 billion kWh in 2050 (about 13% of total generation). We also envision the addition of nuclear power to the electricity fuel mix during the outlook period, starting in the mid-2030s, but its share of generation remains relatively small in 2050 at around 6%, similar to the share of solar (see Figure 2.7 Outlook for Kazakhstan's primary energy consumption by fuel to 2050).

Despite its smaller role in 2050, coal can provide an important "energy security blanket" for Kazakhstan during the energy transition. Kazakhstan's indigenous coal is low-cost to produce and is readily available in large quantities, and does not require new or imported technologies to produce or deliver to consumers. Although a major drawback is its high carbon-intensity, as Kazakhstan shifts to cleaner fuels that are either imported (natural gas) or higher cost or dependent on imported technologies and equipment (solar, wind, hydrogen), low-cost indigenous coal (even as its use winds down) can serve as an important stabilizer or anchor in offsetting the inherent risks posed by these other energy sources to availability and affordability. And where coal consumption is necessary, a number of technologies can be employed during its extraction and combustion to increase the efficiency of its extraction and use, and reduce harmful emissions—ultra-supercritical steam cycle generation and integrated gasification combined cycle generation in electric power production, CCUS in power generation and industry, and the use of best-available technologies (BAT) to reduce methane emissions during coal mining.[92]

Kazakhstan's net primary energy exports in 2022 (87.1 MMtoe) increased slightly relative to 2021, but remained below the immediate pre-pandemic level of 94.2 MMtoe achieved in 2019. Kazakhstan's net exports of oil and oil products, which accounted for 77.2% of total net primary energy exports in 2022, declined slightly in 2022, by 0.6% to 67.2 MMtoe, as market disruptions following the onset of armed conflict in Ukraine unsettled oil markets. Net exports of gas (primarily to China) contracted more sharply in 2022 by 43.1% to 2.9 MMtoe, as domestic consumption increased. Conversely, net exports of coal increased modestly, as a result of higher demand in Europe as the EU and UK banned imports of Russian coal. S&P Global expects net exports of coal to continue to contract over time as the energy transition takes hold more firmly globally.

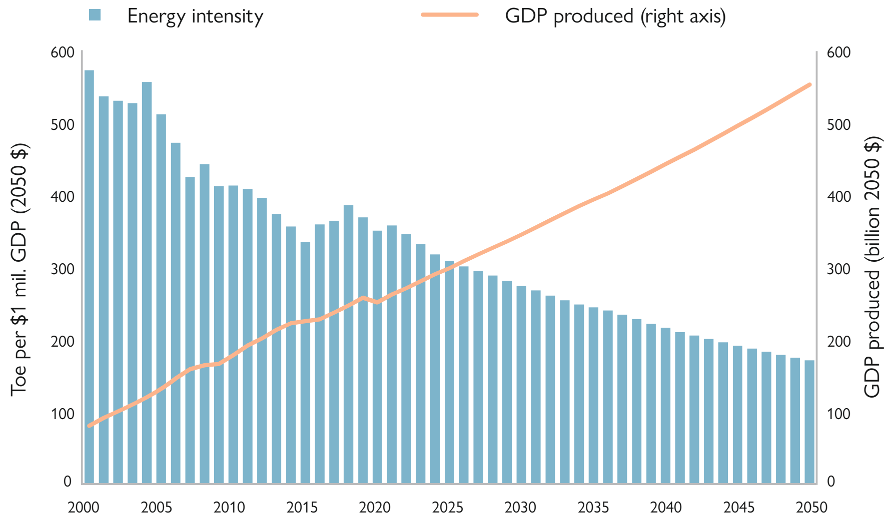
Overall net primary energy exports are expected to reach a maximum of 109.1 MMtoe in 2025. Subsequently they trend downward over the outlook period, declining to 52.5 MMtoe in 2050. This reflects the anticipated longer-term drop in nearly all fuels—oil, gas, and coal—while net exports of (primary) electricity remain negligible. Coal exports diminish to 7.8 MMtoe in 2050, while net exports of oil and petroleum products contract to 47.8 MMtoe in 2050. Kazakhstan switches from being a net gas exporter to a net gas importer in the 2040s. This reflects our assumptions of increased gas demand (due in part to accelerated coal-to-gas switching in the power sector) and relatively flat commercial Kazakh gas production longer term.

A decidedly positive trend in Kazakhstan's energy performance in recent years and in our base-case outlook is the continuing decline of the energy intensity of Kazakhstan's economy – a long-term dynamic in evidence since independence. Measured as the tons of oil equivalent (toe) consumed to produce a million dollars of GDP (in real 2005 dollars), Kazakhstan's energy intensity decreased in 2022 by 3.2%; for the period 2000-23, the total decrease in energy intensity was 39.6%. Kazakhstan still displays a comparatively high energy intensity level in global terms,[93] but in the outlook period continues to demonstrate strong energy efficiency gains – reducing energy intensity by 49.5% (2.5% annually) during 2023-50 (see Figure 2.8 Kazakhstan's energy intensity dynamics in the base case to 2050).

92 These technologies are discussed in some detail in *The National Energy Report 2017*, pp. 152-154 and *The National Energy Report 2021*, pp. 162-165.

93 Kazakhstan's energy intensity in 2020, as measured by the International Energy Agency (https://www.iea.org/reports/sdg7-data-and-projections/energy-intensity), was 5.8 megajoules per $US (in 2017 GDP at purchasing power parity); the world average for 2020 was 4.6 megajoules per $US.

Figure 2.8 Kazakhstan's energy intensity dynamics in the base case to 2050



Source: S&P Global Commodity Insights.

2.9 Key Takeaways on Energy Security and Affordability and the Energy Transition

It is understandable for countries to take short-term, emergency measures to provide relief during periods of high energy costs, such as price capping or suspension of certain taxes, to ease the burden on consumers, especially the most vulnerable and during periods of market turmoil. But these measures should be implemented in such a way that they do not worsen the investment environment for both low-carbon as well as traditional energy sources and technologies that are vital for overall energy supply and the transition to cleaner and more resilient energy systems.[94] More specifically, global experience strongly indicates that the most effective way for government to help people impacted by high energy prices is not to reduce or cap prices by administrative means, but rather to explore ways of helping consumers access alternative low-cost energy sources (when choices are available), use energy more efficiently, and through temporary measures such as releasing emergency fuel reserves or suspending or reducing fuel taxes. Price ceilings do little to reduce energy consumption or expand supply, and market pricing plays a strong role in curbing excessive demand and allocating the various sources of energy to their most important and effective ("highest value") uses in the economy.

Listed below are various strategies Kazakh energy policymakers might consider when attempting to reduce the level of subsidization of energy prices throughout the economy, while at the same time avoiding major disruption for both producers and consumers and mitigating public opposition:

- ***Differentiated prices,*** with higher rates being applied to large consumers to more effectively incentivize conservation and efficiency measures
- ***Stepping up cross-border energy trade*** to expand supply and potentially reduce overall costs, particularly if imports are cheaper than domestic production (e.g., natural gas, diesel)
- ***Implement targeted direct subsidies,*** limited to the lowest-income households, in the form of direct financial assistance to pay utility bills or finance home energy efficiency retrofits. Subsidies that protect the poorest fifth of the population in some European countries are estimated to cost only about 0.4% of GDP, and the poorest two-fifths of the population, 0.9%.[95]
- ***Implement energy efficiency programs*** to reduce electric power consumption by households and businesses; these can include incentives or credits for energy-saving renovations and the purchase of newer, more efficient appliances, and conducting home and business energy audits
- ***Launch public awareness campaigns*** to inform consumers about the appropriate use of electricity and other energy sources and the benefits of adopting energy-efficient practices
- ***Temporarily reduce or suspend excise taxes on refined products.*** This approach was widely employed (e.g., in Europe, Australia, and some state governments in the United States) in 2022 during the period of high energy prices.[96]
- ***Implement selective conservation regulations,*** such as prohibitions or mandatory reductions in electricity use (e.g., in business or street lighting during non-business hours) and adjustments to heating and/or cooling levels in public buildings
- ***Releases from national fuel reserves.*** For specific situations, a release of crude oil and refined products from national petroleum reserves may be necessary to mitigate high energy prices. Such an approach was considered necessary in April

94 https://www.iea.org/commentaries/what-is-behind-soaring-energy-prices-and-what-happens-next.

95 https://www.economist.com/leaders/2022/08/10/how-to-help-with-energy-bills.

96 https://www.energymonitor.ai/finance/how-governments-are-shielding-consumers-from-surging-energy-prices/#catfish .

2022 after the start of the Russia-Ukraine conflict, when the 31 member-states of the International Energy Agency announced the release of tens of millions of additional barrels into world oil markets. The move followed a similar announcement by the United States of an emergency 180 MMb release from its Strategic Petroleum Reserve. This strategy, however, is now complicated by the fact that these reserves will need to be replenished by purchases at higher prices as a result of recent supply management policies instituted by OPEC+.

Another typical action during periods of high energy prices is to simply tax the windfall profits of the energy companies (often aimed at providing funds for governments to cover other subsidy or support programs). However, a broader societal response to high energy prices would seem more prudent. Windfall taxes on energy producers are undesirable if the primary outcome simply becomes underinvestment in capacity and supply (e.g., upstream exploration and production), accentuating the boom and bust of the commodities cycle and leading to future rounds of high energy prices.

2.10 High-Level Takeaways

An effective energy security strategy for Kazakhstan is one that meets domestic energy needs, keeps energy affordable and widely available to consumers, and also makes material progress toward a cleaner energy future. Regardless of whether Kazakhstan (or any other country) meets its emissions reduction and net-zero pledges precisely and on schedule, it is important to continue making progress while meeting the diverse energy needs of its population and businesses. This requires an approach that ensures national energy security is based on the principle of an optimal combination of traditional and renewable sources of primary energy at the national level. While far from constituting a fully formed, articulated energy security strategy, we can identify important elements of such a strategy.

- In order to achieve policy resilience, Kazakhstan's energy sector ultimately needs to function within a broader market-economy framework, allowing market supply and demand fundamentals to drive prices and allocate resources. Demonopolization may be needed in certain segments and activities to allow market forces to operate effectively. In other sectors, notably the natural monopolies or networked sectors, more effective and flexible regulatory approaches are needed for market forces to function.
- Kazakhstan should adopt a general open-trade stance internationally with respect to energy, to drive greater efficiency and market-oriented prices. As such, this entails general acquiescence to the emerging EAEU free-trade regime, although care should be exercised to balance the benefits of integration with Kazakhstan's domestic energy security needs. These issues are addressed in greater detail in Chapter 3.
- Policymakers should seek to limit state participation in domestic energy markets, intervening selectively and judiciously only when necessary to alleviate obvious market shortcomings or achieve specific policy goals.
- The role of coal in the domestic economy should be reduced, but carefully and gradually; this low-cost, domestically available fuel provides essential ballast for the greater risks involved in the other elements of the overall energy transition.
- Natural gas is one of the cheapest and most effective fuels for decarbonization over the next 1-2 decades; its role in the economy needs to be expanded, even if doing so increases overall reliance on imports to achieve wider penetration. However, careful planning should be devoted to its allocation for various uses, to reduce the potential for wasteful consumption and to avoid disruptions for the economy and the population (pricing).
- When increasing the role of renewables in electricity generation, caution should be exercised in its pace in order to maintain system reliability and general affordability of electricity for consumers; this may require a revamping of the existing support scheme (see the Chapter on electric power).
- The reliability of the existing grid should also be enhanced through targeted investment to ensure uninterrupted and expanded power supplies for both consumers and industry from infrastructure already in place; existing facilities can contribute significantly to the goal of greater electrification during the transition period while renewable generation reaches its full potential.
- Energy security for Kazakhstan needs to be enhanced by diversifying export routes for crude oil, to reduce the overall risk of adverse developments occurring on any single route or in any single export market.
- Kazakhstan's energy security actions also should extend to maintaining diversity among investor-countries and investor-types in foreign direct investment in the energy sector; consequently, this entails creating and maintaining an attractive investment environment given increased global competition for this type of financing.

2.10.1 A national energy security strategy for the Republic of Kazakhstan

Given the outsized and increasing importance of the energy complex in Kazakhstan's economy, a national policy priority should be the drafting and codification of an energy security strategy (Energy Security Strategy of the Republic of Kazakhstan to 2050) as one of the foundational state planning documents. As a formal Strategy, it will unite existing concepts in the fields of energy, environment, subsoil use, etc. within one document and inform and influence the formation of strategic plans of all government bodies, so that the strategic directions of various government agencies involving energy security are coordinated and harmonized. By eliminating the friction between contradictory state energy policies—some which seek to maximize energy production and others which aim to curb consumption (energy saving)—the harmonization of existing concepts will ultimately have a synergistic effect, strengthening energy security.

Such a strategy will need to be dynamic or evolving—rather than static or fixed—given the fluid nature of both the global geopolitical environment and the domestic scene. The Strategy will need to flexibly respond to changing conditions in order to maintain a proper balance between energy, the national economy, and the well-being of the environment and population. Importantly, it also must be focused on the specific needs of Kazakhstan, as each country faces its own specific energy security challenges. An energy security strategy for Kazakhstan must address the following key energy vulnerabilities:

- The high concentration (over 95% in 2022) of Kazakhstan's crude oil exports that transit a third country (Russia) to reach world markets, and the high percentage of total exports (82%) exported along a single pipeline—the Caspian Pipeline Consortium (CPC) pipeline route.
- An electric power system with a relatively high level of wear and tear, much of it installed over four decades ago, which is increasingly susceptible to outages and has received inadequate investment for many years.
- Insufficient strategic fuel storage capacity. *Operational* ("everyday") crude oil storage capacity in Kazakhstan presently appears adequate to cover domestic refinery needs in the event of a short-term disruption to regular supply; however, *strategic* storage capacity must be added to offset sudden and unexpected reductions in export demand or export capacity (pipelines). Refineries have operational storage for finished products, but these volumes are relatively small, particularly for products in high demand (e.g., diesel, A-95 gasoline). Additional strategic storage capacity is needed to avoid refinery shutdowns due to unforeseen events. The country's natural gas storage capacity, although presently adequate to meet some three months of 2022-level domestic consumption, will nonetheless need to be expanded in light of projected future increases in domestic gas consumption.
- The need to ensure diversification of future natural gas imports, as the country gradually shifts toward increasing imports of natural gas as the gasification program proceeds.
- A need to ensure diversification of supply of high-demand refined products such as diesel, jet kero, and A-95 gasoline by further adjustment of the domestic refinery mix, price liberalization to incentivize consumption efficiency (and eliminate unauthorized exports), and diversification of import sources.
- A need to preserve high levels of transit gas in the country's national system of trunk pipelines, which will provide a vital source of income for QazaqGas even if Kazakhstan's gas exports gradually decline in the future.
- Limited supplies of fresh water, a vital input for energy production in such wide-ranging activities as oilfield reinjection, uranium production through the *in situ* leaching method, and electrolysis of green hydrogen in a massive proposed clean-energy project in Mangystau Oblast.
- The continued need for improvements in energy efficiency, which enhances energy security by making energy previously consumed wastefully available for other uses.
- The looming energy security challenge from the build-out of intermittent renewable generation capacity, which will test system resilience and put a premium on reliable reserve baseload capacity, including from coal.
- The need to increase investments in energy R&D and training of personnel.

The report should follow a process that would enable the identification of concrete steps Kazakhstan could take to address these vulnerabilities. Such a process would include:

- A comprehensive assessment of the country's "margin of safety" for specific energy commodities. Calculation of the margin of safety would be based on an evaluation of geological reserves, state balance data, and forecasts for production and consumption of basic energy resources (oil, gas, electricity).
- The margin of safety would provide a measure of how many days supplies of energy would be available in sufficient quantity in the event of an unforeseen event in the world or in neighboring countries that would necessitate, in an extreme case, the closure of Kazakhstan's borders or the declaration of a state-wide emergency.
- Identification of key gaps in the margin of safety for particular energy commodities (e.g., less than a 10- or 30-day supply) that would require studies to recommend measures Kazakh authorities should undertake to achieve a secure energy supply: (a) for a period of up to one year for strategically important state services (e.g., Ministry of Internal Affairs, Ministry of Emergency Situations, doctors, firefighters, Ministry of Defense); and (b) for a shorter period for the population more generally.
- These measures might include, but would not be limited to:
    - Construction of storage depots for strategic reserves of crude oil and petroleum products (gasoline, diesel, jet fuel)
    - Construction of additional gas storage capacity, with identification of the optimal types (underground, other) and location of facilities
    - Further development of the Laws on Emergency Situations and Civil Protection to enhance energy security
    - Options for providing additional backup power sources at electric power plants, which might include each strategic plant or facility having its own fuel-powered generators for uninterrupted operation or each region having its own autonomous source of energy storage
    - Options for replacement of gas with renewable energy, with identification of the most available renewable resources available for the task.

CHAPTER 3

EURASIAN ENERGY COOPERATION AND REGIONAL ECONOMIC INTEGRATION

3. EURASIAN ENERGY COOPERATION AND REGIONAL ECONOMIC INTEGRATION

3.1 Key Points

► Member-states of the Eurasian Economic Union (EAEU) are pursuing specific programs to harmonize their energy policies that are anticipated to result in a "Single Market" (i.e., unitary markets across the territory of the EAEU) for oil/refined products, natural gas, and electricity by 2025. Although energy policy harmonization is being implemented in many areas, two are expected to have the greatest impact on energy consumers and producers in Kazakhstan—energy pricing and energy transit.

► Within the EAEU framework, the right of non-national companies to access the pipeline system of another EAEU member-state looks like it is going to be governed by the access regime the latter has adopted for its own producers of a specific energy commodity (not affiliated with the owner of the pipeline infrastructure) under its domestic law. In the case of crude oil transit via Russia, extant Russian legislation recognizes the right of all domestic oil producers to non-discriminatory third-party access for *both* domestic and export sales, simply paying an established tariff. Thus, non-Russian producers can utilize the Transneft system to export crude beyond Russia as well, and have been doing so for many years. Given the reduction in Russian pipeline crude exports to Europe following the start of armed conflict in Ukraine, capacity now exists for Kazakh oil along certain routes in the Transneft system that did not exist previously, such as for Kazakh exports of its crude (now rebranded as Kazakh export blend crude oil [KEBCO]) to Germany via the northern Druzhba pipeline, which commenced on 20 February 2023 and is now running at about 100,000 tons per month.

► The issue of pricing of oil and refined products poses a greater challenge for Kazakhstan with the formation of a Single Market. Despite the Government of Kazakhstan's commitment to general price liberalization and market parity, refined product prices in Kazakhstan remain heavily administered and have been kept below (sometimes substantially) those in fellow EAEU member-states. Artificially low prices disincentivize producers to supply the domestic market and lead to the unauthorized/undocumented outflow of Kazakh refined products (especially in border regions) to neighboring states. Price parity between Kazakhstan and its neighbors will need to be achieved primarily by economic measures, such as open market trading via exchanges or liberalizing exports and imports. Despite challenges in the area of price harmonization, progress is evident in three areas: excise tax harmonization, coordinated EAEU actions to curb unauthorized ("grey") exports, and exchange trading.

► Unlike the situation with oil, the issue of gas transit (and gas transportation tariffs) has proven to be a major sticking point for EAEU harmonization efforts. One key issue is whether a uniform gas transportation tariff should be set across the entire EAEU economic space or whether the individual EAEU member-states should set their own tariffs applicable within their own borders, but would apply equally to all gas shipped regardless of national origin or individual shipper. The major gas importer-countries are in favor of a uniform tariff (basically on par with average tariffs in Russia) across the entire EAEU space, whereas Russia—the main gas supplier within the EAEU—is reluctant, as differentiated tariffs within its borders allow for substantial cross-subsidization to occur between long-haul and short-haul shipments within its borders and between export and domestic shipments. The Russians believe such a uniform EAEU tariff would amount to the subsidization by Russia of the gas transportation charges that would be paid by shippers of other member-states.

► A second transit-related issue involves third-party access to Russia's gas pipeline network. Although Russia has allowed gas produced in other states to access its gas pipeline network, such access has been highly restricted, usually to gas that has been purchased by Gazprom for onward delivery or through Gazprom-affiliated entities. No non-Russian producer/shipper has been allowed to directly deliver gas to Russian consumers. Under the evolving EAEU rules, non-Russian suppliers would have to be given the same access to pipelines and consumers as Russian "independent" gas producers now have. Furthermore, the Russian Law on Gas Export (2006) grants Gazprom monopoly access to the pipeline system on its territory for exports, thus precluding any export possibilities for other Russian gas producers. Under the EAEU rules, such export access is therefore similarly denied to gas producers in other EAEU member-states (e.g., Kazakhstan).

► The challenges faced by Kazakhstan in harmonizing its domestic natural gas prices with those of other EAEU member-states in the run-up to the Single Market in gas are similar to those in the oil and refined products market. Kazakhstan's end-user gas prices are among the lowest among EAEU members, and therefore have "the farthest to go" in terms of price harmonization. The potential benefits of a Single Market for gas, as it is currently taking shape, for Kazakhstan—essentially a competing gas producer to Russia—are much less clear than for the gas-importing EAEU member states, especially if access to export markets beyond Russia is essentially precluded. But Kazakhstan does appear to be transitioning to become a larger importer of Russian gas in the future, so the balance may be tipping.

► A major conceptual foundation for the Single Market in electric power is that there will be no supranational EAEU electricity market—existing national electricity markets, including capacity markets, will be maintained—but instead a system of closely integrated national markets will be employed, but operating across national borders in the areas of electricity trade, access to services, interstate power transfers, and information sharing. Substantive progress has been reported in such areas as measurement of interstate electricity balances, (load) compensation, and electricity trading (via free bilateral contracts, fixed term contracts, and 24-hour trade contracts) on three exchanges (St. Petersburg International Mercantile Exchange, Belarusian Universal Trade Exchange, and the Kazakhstan Electricity and Capacity Market Operator). The impacts of the Single Market on Kazakh domestic electricity prices would therefore appear to be limited by the fact that electricity trading will take the form of fixed-term contracts between the designated national power companies of the respective countries, rather than multitudinous transactions between individual producers and consumers of electricity.

► Broad Central Asian cooperation in energy markets and infrastructure to date has been delayed by historical differences over other issues such as water rights and territorial disputes involving Uzbekistan, Kazakhstan, Kyrgyzstan, and Tajikistan—a legacy of Soviet-era boundary delineations. Such differences are not immutable, as evidenced by recent agreements officially resolving Uzbekistan's border claims with Kazakhstan and Kyrgyzstan. Progress in these areas will pave the way for joint infrastructure projects such as the proposed China-Kyrgyzstan-Uzbekistan Railway, creating momentum (and an improving political environment) that could eventually manifest in a broader regional energy trade framework.

► A key prerequisite for joint Central Asian energy projects is financing for investment. The limited financial resources of the individual Central Asian countries appear to have constrained the number and scale of bilateral energy system projects between them to date. Rather than agreements between individual Central Asian countries on the development of energy infrastructure, the bulk of bilateral energy projects in the region instead has involved cooperation with larger, wealthier neighbors such as China, Russia, and UAE. In recent years, China has been the most active energy-sector investor in the region, with that country's financing and joint projects for infrastructure development fitting squarely within the "One Belt, One Road" framework of its foreign economic policy. Russian companies also have been actively involved in the region for many years, although concerns over access to international financing, oilfield services, and parts for equipment at joint projects are emblematic of the new more challenging operating environment for Russian companies in the region in 2023.

3.2 Creation of Single Energy Markets within the Eurasian Economic Union Foreshadows Important Changes in Domestic Pricing in Kazakhstan and Reorientation of Interstate Energy Trade

Kazakhstan is one of the founding members of the Eurasian Economic Union (EAEU), an economic bloc established in 2015 that also includes Armenia, Belarus, Kyrgyzstan, and Russia as full members. As noted on its official website, the EAEU "provides for free movement of goods, services, capital, and labor [and] pursues coordinated, harmonized, and single policy in the sectors determined by the [Union] Treaty and international agreements within the Union."[1] Among the most important sectors targeted for integration is energy, for which the member-states are pursuing specific programs to harmonize their energy policies that are anticipated to result in "Single Markets" (i.e., unitary markets across the territory of the EAEU member-states) for oil/refined products, natural gas, and electricity by 2025.[2] Although energy policy harmonization is being implemented in many areas, two are expected to have the greatest impact on energy consumers and producers in Kazakhstan—energy pricing and energy transit. Because different pricing considerations and rules regulating transit will prevail in the Single Market for each energy commodity, each one is discussed separately below. And because analysis of the general price outlook for the different commodities/markets already has been undertaken in the previous *National Energy Report* (2021)—and our general assessment today remains essentially the same—we will only summarize key pricing issues in this chapter while focusing more heavily on developments affecting energy transit.[3]

3.2.1 Oil and oil products

Crude oil and the refined products derived from its processing are by far the most valuable energy commodities produced in Kazakhstan in terms of overall revenues, the most flexible in terms of their applications, and the most transportable (reflecting the relative relationship between value per unit and transport cost). Consequently, it is not surprising that Kazakh policymakers will be especially vigilant about crude and products pricing and terms of transit as EAEU energy-sector integration proceeds. Integration toward the Single Market in oil/products has proceeded in stages. The first stage, completed in December 2018, involved agreement on the EAEU's common oil and refined products markets formation Program and its approval by the Supreme Eurasian Economic Council (consisting of the leaders of the five EAEU member-states). The second phase, currently in progress and scheduled to be completed this year, involves implementation of the steps stipulated in the Program, including development of unified rules governing (a) access to oil and refined products transportation systems and (b) general and exchange trading of oil and products in member-states. The third phase, to be completed in 2024, would finalize formation of the EAEU common oil and refined products market, culminating in a formal Treaty on 1 January 2025.

3.2.1.1 Transit

Unlike the situation concerning natural gas (discussed below) negotiations concerning Kazakhstan's access to Transneft's pipeline system in Russia for crude exports beyond Russia (i.e., using Russia as a transit country) has not proved particularly contentious.[4] The general principle regarding pipeline access for both crude/products (and natural gas) Single Market is as follows: The right of non-national companies to access the pipeline system of another EAEU member-state is governed by the access regime the latter has adopted for its own producers of a specific energy commodity (not affiliated with the owner of the pipeline

1 http://www.eaeunion.org/?lang=en#about.

2 Currently the energy trade among the EAEU countries is governed mostly by special bilateral trade agreements that cover volumes and terms, pricing, and other issues, such as export duties.

3 For a detailed discussion of energy pricing issues surrounding the creation of these Single Markets, see Kazakhstan Association of Oil & Gas and Energy Sector Organizations KAZENERGY, *The National Energy Report 2021*, pp. 109–112, 137–138, and 177–181.

4 Use of Russian products pipelines to transit non-Russian exports to non-EAEU countries is similarly guaranteed, but has not proven much of an issue in reality, given the small volumes and types of refined products Kazakhstan exports to such markets via Russia as well as the general geography and lay-out of Russia's refined products pipeline system.

infrastructure) under its domestic law. In the case of crude oil, extant Russian legislation recognizes the right of all domestic independent oil producers to non-discriminatory third-party access for *both* domestic and export sales, simply paying an established tariff. Thus, non-Russian producers (both independents and national companies) can utilize the Transneft system to export crude beyond Russia as well, and have been doing so for many years. And in fact, the situation since 2022 seems to be reinforcing this existing acquis: Given the reduction in Russian pipeline crude exports to Europe, capacity now exists for Kazakh oil along certain routes in the Transneft system that did not exist previously, such as for Kazakh exports of its crude (now rebranded as Kazakh export blend crude oil [KEBCO]) to Germany via the northern Druzhba pipeline, which commenced on 20 February 2023 and is now running at about 100,000 tons per month.[5]

Similarly, Kazakhstan has been transiting Russian crude oil to mainland China across Kazakh territory via the KTO pipeline system and the Kazakhstan-China oil pipeline since 2014. The amount has been running at about 10 MMt/y.

3.2.1.2 Pricing

Rather it is the issue of pricing that poses a greater challenge for Kazakhstan with the formation of the Single Market. Despite the Government of Kazakhstan's commitment to general price liberalization and market parity, refined product prices in Kazakhstan remain heavily administered and have been kept below (sometimes substantially) those in fellow EAEU member-states. The social goal of supplying low-cost fuel to retail customers in the domestic market clearly has been a high political priority, but has several negative economic consequences:

- It disincentivizes Kazakh crude producers (who subsidize artificially low retail prices through crude oil sales at prices well below world market levels) and refiners and wholesalers (who receive an extremely limited retail margin) to supply the domestic market.
- It raises energy security issues, leading to the unauthorized/undocumented outflow of Kazakh refined products (especially in border regions) into neighboring countries (e.g., Russia, Kyrgyzstan), where prices are significantly higher (so-called "grey exports").
- Another energy security issue arising from integration is the role of Russian-manufactured refined products in the domestic market. Under the Single Market, Russian refiners, which have ample production capacity, would have unfettered access to Kazakhstan's consumers, potentially displacing Kazakhstan's own products in certain market segments or geographies.

Efforts to address these problems through temporary administrative measures (bans on all exports, limits on the amount that can be purchased, or differentiated pricing, for example) provide temporary relief yet do not really solve the underlying issue, which is the temptation to move products across borders to achieve lower prices or higher margins, rather than supply domestic consumers. Rather, price parity between Kazakhstan and its neighbors will need to be achieved primarily by economic measures, such as open market trading via exchanges or liberalizing exports and imports.

As shall be discussed in some detail in Chapter 5, Kazakhstan is now embarking on product price liberalization, and further liberalization of domestic prices will nevertheless be needed to achieve the Single Market goals of price harmonization across the EAEU economic space. As we observed in *The National Energy Report 2021,* Kazakhstan will need to adjust its domestic pricing policies more than any other EAEU member in order to achieve this goal, because Kazakhstan has the lowest retail gasoline and diesel prices among the five EAEU nations (see Figure 3.1 Average retail prices of A-92 gasoline in selected EAEU countries, and Figure 3.2 Average retail prices of diesel in selected EAEU countries).

Kazakhstan's lower prices within the EAEU reflect its unique position vis-à-vis Russia relative to the other EAEU member states. As a net oil and gas exporter, depending primarily on energy exports to global markets, Kazakhstan directly competes with, rather than complements, Russia. In contrast, the trade structure of the remaining EAEU members, which mainly import Russian energy commodities, is already oriented more strongly toward the economic space of Russia (and Russian pricing). This facilitates their EAEU market harmonization, as they already operate largely according to Russia's general acquis. Given Russia's vastly greater size and economic weight—accounting for 79% of the bloc's population, 86% of its oil output, and 85% of its aggregate GDP—oil prices under any harmonization scenario will inexorably gravitate toward those prevailing in Russia.

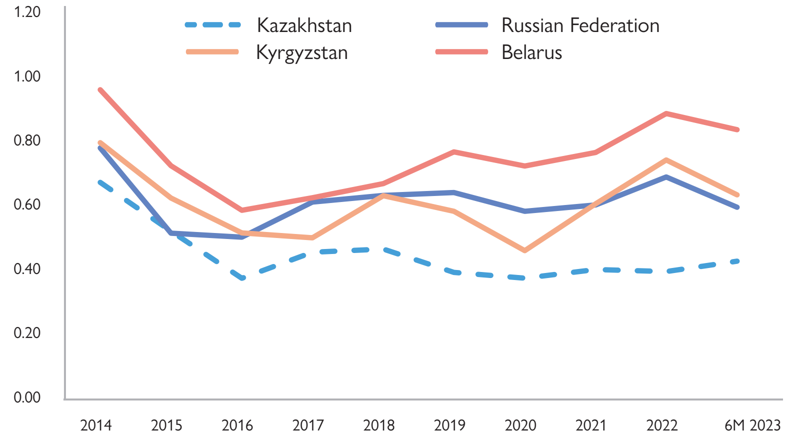
And indeed, in recent months, policymakers at KREM and the Ministry of Energy have increased domestic retail price limits for motor fuels.[6] On 12 April 2023, the maximum retail price of A-92 gasoline rose to 205 tenge/liter from 182 tenge, and diesel fuel to 295 tenge/liter from 230–260 tenge, depending on the region. This, in turn, has stimulated greater demand for autogas (LPG), widely used as a substitute in motor vehicles. The latter currently averages about 80 tenge/liter in Kazakhstan. In June 2023, the Energy of Ministry announced plans to gradually raise retail LPG prices to a level (120 tenge/liter) at which imports from Russia (where there is a sizable surplus of LPG over domestic consumption) would become competitive price-wise domestically, supporting imports if necessary to balance the market.[7]

5 https://www.reuters.com/article/kazakhstan-oil-exports/update-1-kazakhstan-to-send-100000-t-of-crude-to-germany-via-druzhba-in-may-idUSL1N37L1P2 .

6 The Committee for Regulation of Natural Monopolies (KREM) of the Ministry of National Economy of the Republic of Kazakhstan is a state body that controls and regulates activities related to the sphere of natural monopolies and socially significant markets. https://www.gov.kz/memleket/entities/krem/about?lang=en.

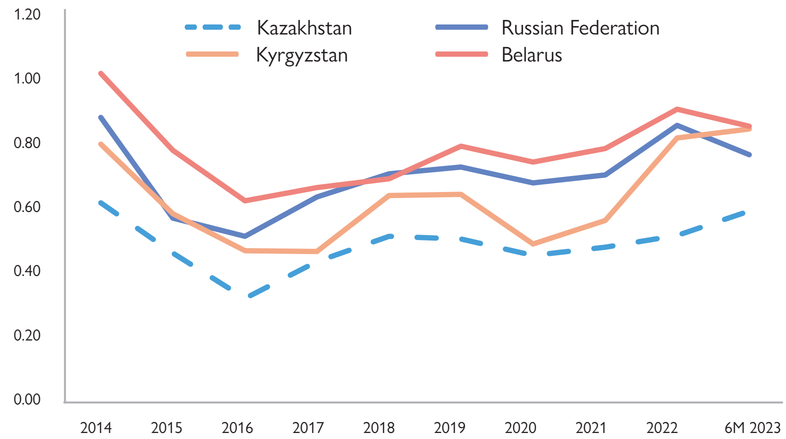
7 See S&P Global Commodity Insights Strategic Report, *An Uphill Struggle: Russia's LPG producers face major new near-term marketing challenges coupled with longer-term feedstock risks,* October 2022.

Figure 3.1 Average retail prices of A-92 gasoline in selected EAEU countries ($/liter)



Source: S&P Global Commodity Insights.

Figure 3.2 Average retail prices of diesel in selected EAEU countries ($/liter)



Source: S&P Global Commodity Insights.

3.2.1.3 Areas of progress

Despite challenges in the area of price harmonization, progress is evident in three areas: excise tax harmonization, coordinated EAEU actions to curb unauthorized ("grey") exports, and exchange trading. On 24 March 2022, the Government of the Republic of Kazakhstan issued Resolution No. 155, which increased excise taxes on gasoline by 10 tenge per liter and on diesel fuel by 20 tenge per liter. This still leaves Kazakhstan's excise taxes at only 39.5% of those in Russia on motor gasoline and 54.2% of those on diesel fuel (see Figure 3.3 Excise Taxes on Refined Products in EAEU countries).

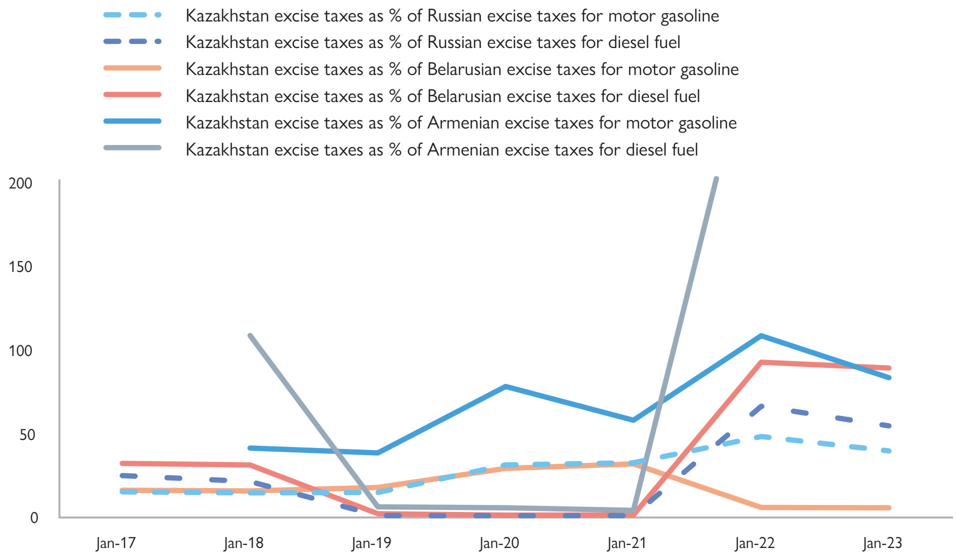
The move is part of a broader effort to bring taxes on petroleum products in line with those in Russia in concert with ongoing EAEU harmonization. Further changes in taxes on fuels and lubricants are envisioned in the lead-up to the planned launch of the Single Market.

On 22 June 2022, the Ministries of Finance, Internal Affairs, and Energy, along with the National Security Committee of the Republic of Kazakhstan, issued a joint order prohibiting the export of gasoline, diesel, and certain other refined products via road transport for a six-month period.[8] Although such product export bans designed to limit smuggling of motor fuels have been fairly common in Kazakhstan in recent decades, the recent ban is harmonized with established EAEU protocols:

- It is based not only on Kazakh legislation but also on Article 29 (and Section 10 of Annex 7) of the EAEU Treaty
- The grades of fuel covered are defined according to standard EAEU specifications
- The joint order directs the Ministry of Energy to notify Kazakhstan's Ministry of Trade and Integration to report relevant information about the ban to the Eurasian Economic Commission per the EAEU Treaty.

8 Excluded were exports in gas tanks provided by the manufacturer of the motor vehicle, as well as in separate receptacles of no more than 20 liters capacity.

Figure 3.3 Excise Taxes on Refined Products in Selected EAEU Member-States (%)



Source: S&P Global Commodity Insights.

Progress in the area of exchange trading (item 35 in the EAEU Program for the oil and products market) is evident in increasing cooperation between Kazakh and Russian exchanges and steps toward the creation of a new commodities trading exchange at the Astana International Financial Center. Kazakhstan's JSC Eurasian Trading System Commodity Exchange (ETSCE; Almaty, Kazakhstan) and Russia's St. Petersburg International Mercantile Exchange (SPIMEX; Russia)—both founded in 2008—have embarked upon several collaborative initiatives in recent years:

- In August 2020, SPIMEX acquired a 5% shareholding in ETSCE. “The transaction was carried out in accordance with the program of inter-exchange cooperation with the bourses of the partner countries as per the agreement on the Eurasian Economic Union” with the stated goal of creating conditions “to develop electronic trading in the common market of EAEU member countries, as well as to bring Russian goods to international markets. SPIMEX's experience assists in launching trading of petroleum products, including LPG and jet fuel.”[9]
- On 9 July 2021, the Astana International Financial Center (AIFC) announced that it would cooperate with ETSCE and its shareholders to develop a commodity exchange (focused on exported commodities) at the AIFC.[10]
- Soon thereafter, on 21 July 2021, the Eurasian Economic Commission (EEC) held its first simulation of an EAEU refined products exchange trading session, in collaboration with SPIMEX (over 60 diesel or gasoline transactions were completed).

As a result of these and other initiatives designed to stimulate the development of exchange trading, Kazakhstan's Ministry of Energy estimates that the share of exchange trading in petroleum products in Kazakhstan would gradually increase from ~10% of output in 2021–22 to 15–20% by 2024.

3.2.2 Natural gas

Work on establishing the EAEU Single Market for natural gas is proceeding on a separate track from the oil/products market; the official Programs for both commodities were approved in December 2018 by the EAEU's Supreme Eurasian Economic Council. Under the first stage of the Program for gas, the countries formulated key principles for the Single Market and worked to harmonize national legislation where needed. The launch of the second stage of the Program for gas was announced at a meeting of the Supreme Eurasian Economic Council on 11 December 2020. Work is to focus on development of the infrastructural, technological, and legal foundations of the Single Market, with a particular focus on developing unified rules governing (a) access to natural gas transportation systems and (b) general and exchange trading of natural gas in member-states. The second stage of the Program is to culminate in the ratification of an intergovernmental agreement for the Single Market (Intergovernmental Treaty on Establishing the Eurasian Economic Union Common Gas Market). A draft of the Treaty was issued by the Eurasian Economic Commission in April 2021, and its details continue to be discussed by member-state representatives, with the goal of its ratification sometime in 2023 and its entry into force on 1 January 2025. In the meantime (2023–24) work on the Program's second stage continues.

3.2.2.1 Transit

Similar to the situation in the Single Market for oil/products, natural gas pricing is a salient issue across the EAEU's economic space. However, the main factor hindering the harmonization path has been the issue of gas transportation tariffs, first when the Program for Gas was approved by the Supreme Eurasian

9 https://interfax.com/newsroom/top-stories/69706/.

10 https://aifc.kz/en/news/commodity-exchange-activities-will-be-formed-and-developed-at-the-aifc.

Economic Council in late 2018 (the decision on transportation tariffs was pushed back to a later date) and pushed back further during several subsequent meetings of high-level negotiating bodies in 2020–22. Active efforts to resolve the issue continue to this day, recently at a 16–17 May 2023 meeting of the Eurasian Economic Commission (heads of the authorized energy authorities of the member states) dedicated to resolving "issues on which the parties have long been unable to achieve consensus." The member-states now appear to have at least temporarily suspended formal meetings on the subject: "The search for solutions on issues sensitive to the parties will continue both on a bilateral basis and at a higher level in order to finalize and adopt fundamental documents on common markets as soon as possible."[11]

Contributing to the intractability of the issue is the fact that the interests of all member-states are involved—not only the gas producer-exporters (Kazakhstan, Russia) but also the gas-importing member-states (Armenia, Belarus, Kyrgyzstan). There are essentially two points of contention. The key point, involving all the member-states, is whether a uniform transportation tariff or rate should be set across the entire EAEU economic space or whether the individual EAEU member-states should set their own tariffs applicable within their own borders, but would apply equally to all gas being shipped regardless of national origin or individual shipper. The major gas importers are in favor of a uniform tariff (basically on par with average tariffs prevailing in the Russian transportation system) across the entire EAEU space, whereas Russia—the main gas supplier within the EAEU—is reluctant, as differentiated tariffs within its borders currently apply to third-party shippers and to Gazprom, and between export and domestic shipments. Substantial cross-subsidization also occurs between long-haul and short-haul shipments within its borders, complicating the deliberations, as the Russians view incorporating such a component into a uniform EAEU tariff as amounting to the subsidization by Russia of the gas transportation costs incurred by shippers of other member-states.

A second issue involves third-party access to Russia's gas pipeline network. Although Russia has allowed gas produced in other states to access its gas pipeline network, such access has been highly restricted, usually to gas that has been purchased by Gazprom for onward delivery or through Gazprom-affiliated entities. No non-Russian producer/shipper has been allowed to directly deliver gas to Russian consumers. Under the evolving EAEU rules, non-Russian suppliers would have to be given the same access to pipelines and consumers as Russian "independent" gas producers now have. Furthermore, the Russian Law on Gas Export (2006) grants Gazprom monopoly access to the pipeline system on its territory for exports, thus precluding any export possibilities for other Russian gas producers. Under the EAEU rules, such export access is therefore similarly denied to gas producers in other EAEU member-states (i.e., Kazakhstan). Such a situation would also then apply to any Russian gas producers/suppliers that sought to operate in Kazakhstan.

11 https://eec.eaeunion.org/en/news/strany-eaes-sblizhayut-pozitsii-po-voprosam-formirovaniya-obshchikh-rynkov-gaza-nefti-i-nefteprodukt/.

3.2.2.2 Pricing

The challenges faced by Kazakhstan in harmonizing its domestic natural gas prices with those of other EAEU member-states in the run-up to the Single Market in gas are similar to those in the oil and refined products market. Kazakhstan's end-user gas prices are among the lowest among EAEU members, and therefore have "the farthest to go" in terms of price harmonization (see Figure 3.4 Regulated natural gas tariffs for residential consumers in EAEU countries). End-user gas prices in Kazakhstan remain heavily administered, and the social goal of supplying low-cost fuel to industrial, commercial, and household customers in the domestic market has been applied for some time. This practice has disincentivized new commercial supply development by Kazakh gas producers (as they already subsidize artificially low consumer prices through gas sales at producer prices well below market levels or their cost of production); even so, domestic sales are a financial loss-making operation for national company QazaqGaz (financial losses from deliveries to the domestic market are offset only by export and transit revenues that allows the company overall to remain financially solvent).

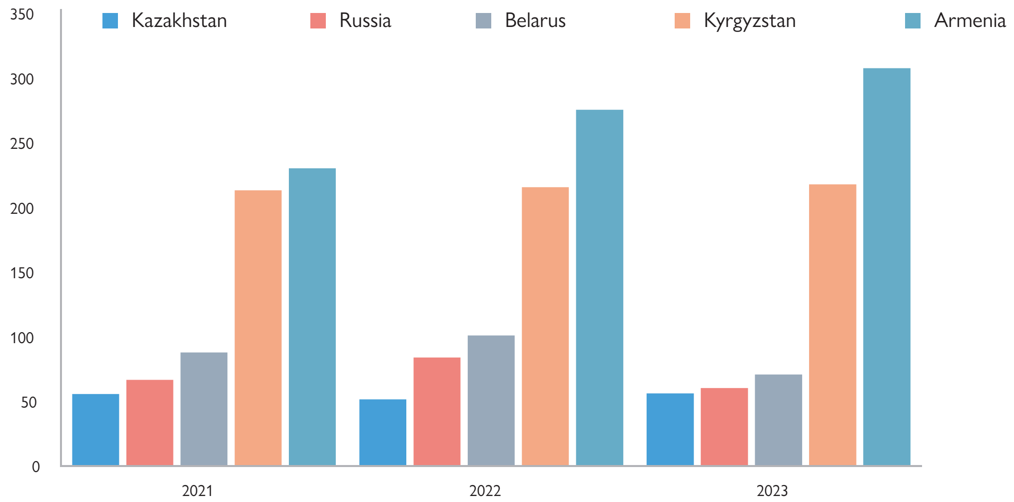
We have observed that under the current schedule for the realization of the Single Market, gas prices in Kazakhstan would need to rise substantially for harmonization to occur. For example, industrial gas prices would need to appreciate by 16% annually during 2021–25 to reach parity with those in Russia's gas-producing regions.[12] In *The National Energy Report 2021,* it was our assessment (similar to that made by Kazakhstan's Energy Minister some years ago) that Kazakhstan should harmonize its natural gas prices with those in Russia's gas-producing regions (e.g., Yamal-Nenets Okrug) and not with the higher prices in European Russia's consuming regions, such as neighboring Saratov Oblast (see Figure 3.5 Price outlook for natural gas consumed by industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug).[13] Such an approach would:

- allow Kazakhstan's manufacturing industry to remain competitive within the broader EAEU economic space
- enable the government to raise consumer prices less substantially (although still significantly) than if some other benchmarks were used
- help QazaqGaz achieve cost-recovery in the domestic segment of its operations
- potentially incentivize new commercial gas production.

12 Russian domestic gas prices are differentiated by consumer group and price zones, depending on transportation distances from the main producing region in West Siberia to consumers. The 16% figure is S&P Global's calculation of how much prices in Atyrau Oblast would have to rise to harmonize with the price level in Russia's Yamal-Nenets Okrug.

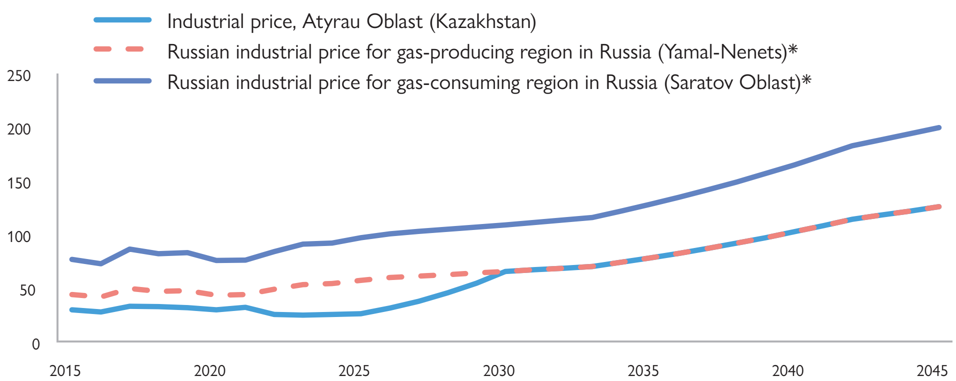
13 *The National Energy Report 2021,* p. 137.

Figure 3.4 Regulated natural gas tariffs for residential consumers in EAEU countries ($/Mcm)



Source: S&P Global Commodity Insights.

Figure 3.5 Price outlook for natural gas consumed by industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug ($/Mcm)



Notes: Prices include VAT. Assumes Atyrau prices close price gap with Yamal-Nenets in 2025-30.
Source: S&P Global Commodity Insights.

3.2.2.3 Gas trading

In addition to transportation and pricing issues, discussions are ongoing concerning the mechanisms that will be allowed for interstate gas trading. When the EAEU was first proposed, the idea was that gas trading across borders would be done via exchanges. But de facto a dual approach has emerged, allowing existing bilateral trade relations to continue, augmented with exchange trading. Presently, exchange trading of gas within the EAEU markets is limited to SPIMEX, involving some Belarusian participation alongside Russian buyers and sellers.

3.2.2.4 Summary

The potential benefits of a Single Market for gas, as it is currently taking shape, for Kazakhstan—essentially a competing gas producer to Russia—are much less clear than for the gas-importing EAEU member-states, especially if access to export markets beyond Russia is essentially precluded. But Kazakhstan does appear to be transitioning to become a larger importer of Russian gas in the future, so the balance may be tipping.

Under the Single Market concept, Kazakhstan essentially cedes control over domestic gas prices, while at the same time accepting more favorable access terms for any Russian gas that it may import or gas that it may transit. The two states appear to be attempting to arrive at a workable compromise on the sidelines of the official EAEU multilateral framework that might involve broader cooperation in gas supply and gas infrastructure under the general umbrella of a "Gas Union" proposed in fall 2022 by President Vladimir Putin for Uzbekistan, Kazakhstan, and Russia (see Chapter 2). Agreement in bilateral talks might achieve the dual objectives of improving the logistics of movements of gas (and electricity) between Russia and Central Asia and increasing Russian deliveries of gas to Kazakhstan's northern and eastern regions. With respect to the former, the existence of transparent and predictable transport tariff rules between Russia and Kazakhstan would not only remove an important obstacle to the realization of the Single Market, but could also facilitate gas swap arrangements with third countries bordering the EAEU, such as Uzbekistan and Turkmenistan, with Kazakhstan at times serving as a transit state.[14] With respect to the latter, talks are continuing, although they were described as “complicated” in early June 2023 by Kazakhstan's Energy Minister Almasadam Satkaliyev, who opined that the new Russian supplies “would not be cheap.”[15]

3.2.3 Electric power

Development of a Single Market for electric power in the Eurasian Economic Union has followed a somewhat different track than that for oil/products and natural gas. A commitment to proceed with work on the creation of a Single Market in electric power was reached in April 2019 (slightly later than approval of the oil/products and gas Programs in December 2018), with a draft international agreement (Protocol) establishing the legal basis and principles of the operation of the Single Market, and the areas to be regulated by its rules. The agreement was subsequently approved by the Supreme Eurasian Economic Council. The agreement authorized the Eurasian Intergovernmental Council and the Eurasian Economic Council to adopt acts regulating the Single Market; identified participating entities and organizations as well as bodies and organizations responsible for its operation; and outlined the modes of trading electric power on the Single Market.[16]

Work toward creation of the Single Market is organized under the terms of a document entitled “Protocol on Amendments to the Treaty of the Eurasian Economic Union,” which had been ratified by all parliaments of the member-states by 5 April 2022. A major conceptual foundation for the Single Market is that there will be no supranational EAEU electricity market—existing national electricity markets, including capacity markets, will be maintained—but instead a system of closely integrated national markets will be employed, but operating across national borders in the areas of electricity trade, access to services, interstate power transfers, and information sharing. This configuration of the Single Market reflects historical experience in the operation of an interstate power system that included two of the member-states (Kazakhstan, Kyrgyzstan) in the Soviet and immediate post-Soviet periods. However, the greater integration of Central Asian electricity grid will likely continue to be hobbled by the fact that since independence each of the Central Asian states has prioritized the security and independence of their own electric grids over a general system (see box “Soviet-Era Central Asian Integrated Power System Collapses Because of Competing National Power Goals.”).

Soviet-Era Integrated Central Asian Power System Collapses Because of Competing National Power Goals

During the Soviet period, the Central Asian Unified Energy System (UES) power system (or “pool”) was part of the Soviet Union's national grid, with a central dispatch for this regional system in Tashkent, Uzbekistan. It was operated in parallel with other regional Russian grid systems, such as those within Russia or the (coal-fired) Northern Kazakhstan network.[17] The Central Asian system was unique in the sense that electric power systems elsewhere in the USSR coincided with union republic borders or with regions within republics. Meanwhile, the Central Asian Grid united several different republics, some rich in hydro-power resources and others possessing abundant thermal power, so that flows of electricity varied depending on the season and prevalence of generation type in that season. With an integrated power grid and the composition of Central Asia's power capacity in each state being so diverse, after the Soviet break-up the successor countries initially expressed a unilateral intention to continue running the Central Asian dispatch centrally. But true cooperation was never achieved, as the differing uses of water and power inevitably led to disagreements that ultimately led to the effective disintegration of the broader regional grid.

The primary disagreement that hindered cooperation was related to the role of hydroelectric power plants (HPPs) located in the upper reaches of rivers in the mountainous terrain of Kyrgyzstan and Tajikistan in regulating the large volumes of water flowing north for the needs of agriculture in the republics that are located along their lower reaches (in Kazakhstan, Turkmenistan, and Uzbekistan). Essentially, this meant that in summer months, when agricultural needs for water were greatest for irrigation, HPPs along the Amu Darya and Syr Darya river systems (and their tributaries) would release higher volumes of water and naturally generate more power for the region. Conversely, in winter months, when agriculture needs were less, hydropower facilities were used more to store water in their reservoirs; with less hydropower generation, regional thermal power plants then would take up the power slack. However, the opposite frequently occurred in the USSR, with hydropower increasing in the higher power-demand winter months because of the role HPPs played in balancing power systems (providing reactive power during spikes in power demand). So, in contradiction to the somewhat utopian Soviet ideal, hydropower use in the region often exaggerated summer droughts and winter flooding in the region, prompting bureaucratic ministerial battles between officials representing electric power and agricultural interests as well as republic officials.[18]

Following the disintegration of the USSR, leaders in each of the newly independent Central Asian states increasingly began to act according to their own national interests, prioritizing

14 See S&P Global Commodity Insights, Russia Watch, *Damage Control: How is Russia's energy industry adapting to intensified Western sanctions and new domestic political and economic constraints?* March 2023, p. 51.

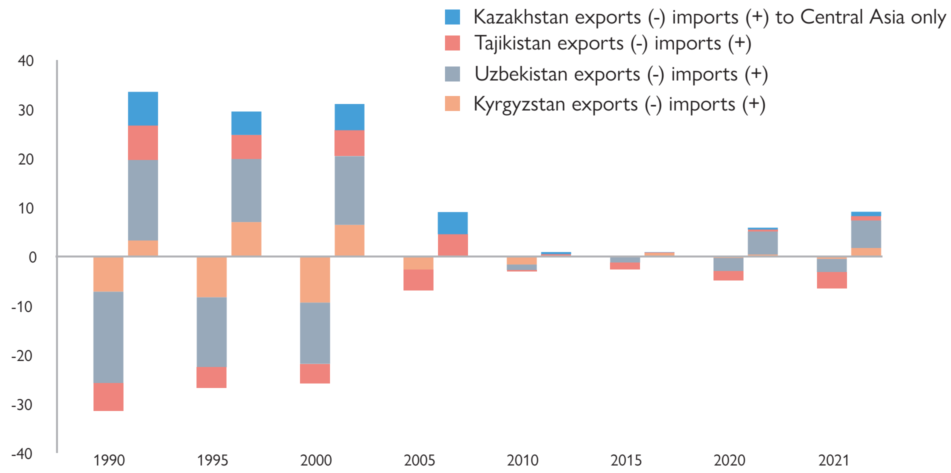
15 *Argus Eurasia Energy,* 8 June 2023.

16 https://www.inform.kz/en/eaeu-reaches-agreement-on-common-electricity-market_a3520056.

17 More specifically, the Central Asian integrated power system consisted of the southern part of Kazakhstan, as well as the national energy systems of Uzbekistan, Tajikistan, Kyrgyzstan, and Turkmenistan. It united 83 power plants connected by a network of 220 and 500 kV lines.

18 For background, see IHS CERA Decision Brief, *Central Asian Hydro Dispute Heightens Tensions between Upstream and Downstream Neighbors,* May 2013.

Figure 3.6 Central Asian electricity trade (billion kWh)



Source: S&P Global Commodity Insights.

grid reliability and security over multilateral cooperation. By 2019, electricity trade of the Central Asian states fell manyfold compared to 1980s levels, although there has been an uptick in trade since 2020, largely due to a tight electricity balance in Uzbekistan (see Figure 3.6 Central Asian electricity trade). In 2003, Turkmenistan was the first to officially exit the Central Asian UES because the gas-rich state found autarkic operation more stable. By 2008, new 500 kV transmission links built in Tajikistan and Kazakhstan gave these countries greater power independence from the legacy grid, changing the dynamics by which they relied upon their neighbors for power sharing and complicating cross-border power flows across the entire region.[19] The unruly power-sharing relationship led the central power bond to unravel, with Kazakhstan pulling out of the Central Asian UES in 2008. In protest over Tajikistan's hydropower plans, Uzbekistan followed in 2009. Although some collaboration continues between Kazakhstan, Uzbekistan, and Kyrgyzstan to support the stability of their respective national systems, Tajikistan and Turkmenistan still remain officially independent of any organized Central Asian water and power cooperation.

Progress toward actual realization of the Single Market—like the oil/products and gas common markets scheduled for 1 January 2025—has been marked both by successes and challenges. In an interview on 7 December 2020, a representative of the Chairman of the Board of the Eurasian Economic Commission indicated four outstanding areas of work that were expected to be completed in mid-2022 or mid-2023 and approved by the Eurasian Intergovernmental Council before the launch of the Single Market in 2025.[20] These involved the formulation and approval of documents outlining rules (procedures) governing:

- Mutual trade in electricity (via free bilateral contracts, fixed term contracts, and 24-hour trade contracts), with an expected completion date of 1 July 2022
- Access to services for interstate transmission of electricity; expected to be completed by 1 July 2022
- Definition and distribution of the throughput capacity of interstate transmission lines; expected to be completed by 1 July 2022
- Information exchange; expected to be completed by 1 July 2023

Yet less than one year later, in a news report dated 10 February 2022,[21] the deadline for approval for the documents was pushed back to "2022 and 2023," and as of this writing, the Intergovernmental Council has approved only the document on access to services for interstate transmission of electricity.[22] However, at an 8 June 2023 meeting between representatives of the Eurasian Economic Commission's Subcommission on the Formation of a Common Electricity Market and SPIMEX, clarification of draft rules for centralized electricity trading and the exchange of information were discussed. SPIMEX has been designated as one of the three bodies where centralized trading of electricity under fixed-term contracts will be allowed (the other two are the Belarusian Universal Trade Exchange and the Kazakhstan Electricity and Capacity Market Operator).[23]

Substantive progress has been reported in such areas as measurement of interstate electricity balances and (load) compensation. More specifically, it has been agreed that in the Single Market, electricity will be measured on interstate transmission lines (rather than at points of production or consumption) for the purpose of determining electricity balances

19 Uzbekistan would frequently overdraw from the regional grid, disrupting a new north-south Kazakh link and causing power shortages in parts of Kazakhstan. Tajikistan would also overdraw, mainly in winter months.

20 https://eng.belta.by/economics/view/most-of-eaeu-common-electricity-market-rules-expected-to-be-ready-by-mid-2022-135642-2020/.

21 https://www.camarabelarus.com/en/blog/446-eaeu-countries-agree-on-the-functioning-of-the-common-electricity-market.

22 Yevraziyskiy Mezhpravitel'stvenniy Sovet, "Resheniye: Ob utverzhdenii Pravil dostupa k uslugam po mezhgosudarstvennoy peredache elektricheskoy energii (moshchnosti) v ramkakh obshchego elektroenergeticheskogo rynka Yevraziyskogo ekonomicheskogo soyuza," 3 February 2023, Almaty.

23 https://eec.eaeunion.org/en/news/emps-prinyal-reshenie-ob-operatore-tsentralizovannoy-torgovli-elektroenergiey-na-sutki-vpered-na-obshch/.

between neighboring states. Agreement also was reached on compensation for deviations between actual and planned interstate electricity balances: ". . . deviations of the actual hourly production and consumption volumes of the subjects of the internal wholesale electricity markets from the planned values, including taking into account transactions on the Common Electricity Market of the EAEU, are subject to compensation by these subjects on the internal wholesale electricity market in accordance with the legislation of the member-state."[24]

Perhaps the most salient difference in the electricity Single Market (from the oil/products and gas markets) is that at present its impacts on Kazakh domestic electricity prices appear to be limited by the fact that electricity trading will take the form of fixed-term contracts between the designated national power companies of the respective countries, rather than multitudinous transactions between individual producers and consumers of electricity. In other words, the trade in electricity is limited only to specific transboundary trade transactions, with ownership of the commodity (electricity) being transferred (to the respective national power company) at the borders between EAEU member-states. Further, the volume of electricity flows—in the form of imports/exports or interstate flows for balancing purposes—appears to be quite limited at present. The Russian Federation, for example, exported only 0.3% of the electricity it produced in 2022 (4.5 billion kilowatt-hours [kWh] of a total of 1,138 billion kWh) to the Commonwealth of Independent States (CIS; a broader coalition of nine Eurasian states that includes all the EAEU members) and imported a truly minuscule quantity (0.5 billion kWh of 1,123.3 billion kWh) from the CIS.[25] At a meeting of Kazakhstan's Mazhilis (lower house of parliament) on 19 January 2022, then-Minister of Energy Bolat Akchulakov stated his belief that the Single Market would not directly lead to a rise in prices, because it prescribes only rules of cooperation.[26] Such rules include the right of an organization authorized for interstate electricity transmission to refuse to undertake a specific trade.

3.2.4 Tensions between Kazakhstan and Russia over coal transit alleviated by reorientation of the two countries' export destinations

Although the EAEU has no specific plans for creating a Single Market in another important energy commodity, coal, differences in interpretation of broad transportation provisions in the EAEU Treaty recently led to tensions between Kazakhstan and Russia over Kazakhstan's rail exports of coal to Asian markets; this occurs via track operated by Russian Railways (JSC RZD) and then shipped to Asian destinations via Russia's Far Eastern ports. As discussed in *The National Energy Report 2021,* following the launch of the EAEU in January 2015, exports of Kazakhstan's coal (and other goods) in the eastern direction became economically feasible (at least in theory) because of the applicability of Russia's unified internal rail tariffs to Kazakhstan's goods transiting to third countries, including via Russian seaports. Although the EAEU Treaty clearly stipulates such equality of access to rail infrastructure and services, shipments on some of the main rail routes to Russia's eastern seaboard have become capacitated, so Kazakh exports were restricted. Kazakh exporters complained about the lack of clearly defined rules stipulating their access to services at the seaports, resulting in a lack of guarantees from month to month that coal exports would not be delayed or blocked in favor of Russian coal or for other reasons.[27] In short, because of the limited capacity of the eastbound rail system and ports, competition with Russian coal tangibly limited the volumes of coal that Kazakhstan could export in this direction.

However, the EU ban on imports of Russian coal on 10 August 2022, which moved westward by rail primarily from mines in the Kuznetsk Basin and then onward via Russia's Baltic and Black Sea ports to Europe, created an opportunity for increased westward shipments of Kazakh coal. Russia reoriented its coal exports toward destinations such as China, India, and Turkey, managing to keep its overall exports from falling by no more than 6.8% on the year. Conversely, Kazakhstan began ramping up exports to Europe in 2022 via Russia, primarily from companies whose coal meets EU emissions standards.[28] Consequently, even prior to the ban, in the first seven months of 2022, Kazakh coal exports to Europe rose to record levels (6.4 MMt, up 45% year on year), surpassing the full-year 2021 total of 5.2 MMt. Primary European destinations were Switzerland, Poland (which had also instituted a ban of rail transit of Russian coal across its territory), Latvia, and Estonia.[29] The expanded European appetite enabled Kazakhstan to export 32.5 MMt of coal (all destinations) in 2022, up 41% from 23 MMt in 2021.[30] However, by 14 September 2022, Kazakhstan's government had become sufficiently concerned about the export momentum detracting from domestic supplies of coal for the fall and winter heating season that it imposed a six-month ban on road (truck) exports of coal (largely to surrounding CIS countries and China, areas immediately adjacent to the country's borders); the ban was later extended another six months by a decree on 27 February 2023.[31]

24 https://www.camarabelarus.com/en/blog/446-eaeu-countries-agree-on-the-functioning-of-the-common-electricity-market.

25 Tsentral'noye dispetcherskoye upravleniye toplivo-energeticheskogo kompleksa, *TEK Rossii,* 2023, no. 1, p. 100.

26 https://jjtv.kz/public/index.php/en/eaeu-countries-to-create-common-electricity-market .

27 *The National Energy Report 2021,* pp. 154–155.

28 Shubarkol Komir, Shubarkol Premium, Karazhyra, Maikuben West, and Saryarka Energy are reported as among the top exporters to Europe (https://thecoalhub.com/kazakh-seaborne-coal-exports-surge.html).

29 https://thecoalhub.com/kazakh-coal-exports-to-europe-surge-to-all-time-high-of-6-4-mio-t-in-jan-jul-2022.html; https://astanatimes.com/2022/12/kazakhstan-increases-coal-production-due-to-high-demand-from-europe/.

30 http://www.sxcoal.com/news/4671838/info/en.

31 https://www.globaltradealert.org/intervention/107127/exportban/kazakhstan-temporary-export-ban-on-coal.

3.3 Integration of Central Asian Energy Markets and Systems

In discussing the potential for greater energy integration within the Central Asian region, it is important to distinguish between energy markets (mechanisms and rules for the trading of energy) and energy systems (the infrastructure used to produce, transport, store, and consume energy). Additionally, integration initiatives within Central Asia clearly illustrate the importance for each Central Asian country of collaboration with external markets, largely due to its investment needs as well as higher complementarity with outside partners compared to the countries within the region.

3.3.1 Energy markets integration

A useful starting point in the discussion of the potential for integration of the energy markets of the individual Central Asian states is the fact—as observed in the preceding section of this chapter—that Kazakhstan and Kyrgyzstan are members of the EAEU and Uzbekistan has observer status. Therefore, to varying degrees, the first two countries are actively implementing measures (common rules and standards) to integrate their markets as part of the movement toward the EAEU "Single Markets" for oil/oil products, natural gas, and electricity, planned to be in place already by mid-decade. And Uzbekistan, as an observer, will at least be familiar with those rules and standards. And Russia is now encouraging Turkmenistan to consider EAEU membership as well. Thus, the EAEU may ultimately provide a framework for expanded multilateral cooperation involving various energy markets across several of the Central Asian states.

Currently, outside the evolving EAEU single markets framework, bilateral agreements are the prevailing instruments through which Kazakhstan cooperates with its neighbors in the arena of sales and purchases of energy. To some extent, broader Central Asian cooperation in energy markets has been delayed by historical differences over other issues. These include conflicts over water rights (between the upstream states of Tajikistan and Kyrgyzstan and downstream states of Uzbekistan and Turkmenistan) and territorial disputes involving Uzbekistan, Kazakhstan, Kyrgyzstan, and Tajikistan—a legacy of Soviet-era boundary delineations. Such differences are not immutable, as evidenced by recent agreements officially resolving Uzbekistan's border claims with Kazakhstan and Kyrgyzstan.[32] Progress in these areas paves the way for joint infrastructure projects such as the proposed China-Kyrgyzstan-Uzbekistan Railway, creating momentum (an improving political environment) that could eventually manifest in a broader regional energy trade framework.

32 https://central.asia-news.com/en_GB/articles/cnmi_ca/features/2023/01/12/feature-02.

3.3.2 Energy systems integration

When the subject turns to the integration of energy *systems* —interlinked infrastructure that facilitates physical flows of energy—the first prerequisite, once energy security concerns have been met, is financing for investment in joint projects. This is apparent both in the bilateral agreements concluded by the Central Asian states with external partners as well as in two international "mega-projects" seeking to deliver Central Asian gas and electricity to South Asian markets.

3.3.2.1 TAPI and CASA-1000

Two multilateral projects designed to integrate the Central and South Asian energy systems—the Turkmenistan-Afghanistan-Pakistan-India (TAPI) natural gas pipeline and Central Asia–South Asia electric power transmission project CASA-1000—are both formally "under construction," with segments of infrastructure completed in Central Asia. Yet both are, in reality, currently suspended and far from completion. After long periods of sporadic activity on these projects, this is primarily because of lack of financing as a result of the challenging security and political situation in the transit country of Afghanistan.

Construction of TAPI (33 Bcm/y capacity), which aims to source gas from Galkynysh (Phase 2) and other fields in Turkmenistan, reportedly began in 2015 (although the original MOU was signed much earlier, in 1995). Construction of the (short) pipeline segment in Turkmenistan is now complete and work on the Afghan section began in 2018, but is now stalled due to the Afghan government's lack of funding for a security force to protect the pipeline. A search is underway for an international source of funding for the security force. In the meantime, the commitment of one of the two major gas end-consumers (India) to continue its involvement in the project appears to be wavering. But Pakistan has stated that if India withdraws, it may be willing to purchase India's proposed share of gas.[33]

Until recently, CASA-1000 appeared to be the closer of the two projects to completion. The CASA-1000 transmission lines aim to move electricity at high voltage between Kyrgyzstan and Tajikistan and then from Tajikistan to end-consumers in Afghanistan and Pakistan. It will include 1,387 km of high voltage alternating current (HVAC) and high voltage direct current (HVDC) transmission lines, with a total capacity of 1.3 GW/y during the summer months (1 GW allocated to Pakistan, 300 MW to Afghanistan). Groundbreaking was in 2016, and until 2021 the project appeared to be on pace for completion in 2023. However, following the US departure from Afghanistan in August 2021 and the deteriorating security situation in the country, construction has come to a halt. The reason reported for the delay is the withdrawal of financing by the World Bank ($245 million) and the US Agency for International Development. As in the case of TAPI, project participants are reported to be searching for alternative sources of funding.[34] Although the project potentially affords possibilities for Kazakhstan—the

33 https://www.pipeline-journal.net/news/pakistan-move-forward-tapi-gas-pipeline-project-even-without-india. For background, see IHS Markit, *Analysis of the Feasibility of the TAPI Pipeline and Potential Impacts on Regional and Global Gas Markets*, October 2019; and the IHS Markit Insight, *TAPI pipeline: Still a pipe dream*, October 2020.

34 https://tolonews.com/business-182159.

abundant coal resources of north-central Kazakhstan could be used to generate electricity that could be transmitted southward to CASA-1000 during winter to augment low seasonal hydroelectric generation in Tajikistan and Kyrgyzstan—this would have a negative impact on Kazakhstan's efforts to achieve its greenhouse gas emissions reduction commitments and would likely require additional investment in Kazakhstan's high-voltage electricity transmission network.

3.3.2.2 International development bank and other financing[35]

A number of international development banks are involved in financing energy infrastructure in Central Asia, including the World Bank, the European Bank for Reconstruction and Development (EBRD), Asian Development Bank (ADB), Asian Infrastructure Investment Bank, and Islamic Development Bank. Nonetheless, their overall level of activity in the region is relatively limited; in 2021, the Central Asian countries received only 4% of the total climate finance provided by international development banks to low- and middle-income countries. Presently there are 104 ongoing international development bank–financed projects in Central Asia, involving mostly water resources and energy systems with a total value of $10.2 billion. The EBRD tops the list of funding providers with a portfolio of $3.3 billion, followed by the World Bank ($3.0 billion) and ADB ($2.6 billion).

Within Central Asia, one of the more important multilateral institutions currently helping finance new energy-sector infrastructure is the Eurasian Development Bank (EDB), established in 2006 and headquartered in Almaty. Although consisting of the five EAEU member states plus Tajikistan, it has no formal affiliation with the EAEU. The EDB to date has participated in the co-financing of hydro, solar, and wind power projects, investing more than $700 million in green infrastructure and energy efficiency projects in the member-countries.

Finally, financing for clean-energy projects in Kazakhstan and other Central Asian countries is being discussed within the framework of economic forums organized by the European Union and the US Agency for International Development (USAID). The first USAID–Central Asia Clean Energy Forum convened in Almaty on 13–15 September 2022 to explore emerging clean-energy investment opportunities in the region. It was organized under the auspices of a five-year, $40 billion USAID “Power Central Asia” program (2020) to develop the region's energy sector, invest in clean energy, and promote trans-boundary trade. One of the outcomes of the forum was the establishment of a virtual platform for the sharing of information on technological innovation in the renewable energy sector.[36] Not long thereafter, the second European Union–Central Asian economic forum was held in Almaty, Kazakhstan on 18 and 19 May 2023. Although the EU forum does not provide financing directly, it does offer a pathway to investment financing for clean-energy projects by affiliated banks such as the EBRD and European Investment Bank.[37]

35 E. Vinokurov, C. Albrecht, E. Klochkova, A. Malakhov, V. Pereboev, and A. Zaboev. *Global Green Agenda in the Eurasian Region. Eurasian Region on the Global Green Agenda.* Almaty: Eurasian Development Bank, Reports and Working Papers 23/2, 2023, pp. 4, 11, 25.

36 https://primeminister.kz/ru/news/reviews/kak-proshel-vtoroy-ekonomicheskiy-forum-evropeyskiy-soyuz-tsentralnaya-aziya-24191.

37 https://www.eeas.europa.eu/delegations/kyrgyz-republic/second-european-union-%E2%80%93-central-asia-economic-forum-was-held-almaty_en?s=301.

3.3.2.3 Bilateral projects

The limited financial resources of the individual Central Asian countries constrain the number and scale of bilateral energy system projects between them. Rather than agreements between individual Central Asian countries on the development of energy infrastructure, the bulk of bilateral energy projects in the region instead has involved cooperation with larger, wealthier neighbors such as China, Russia, and UAE. In recent years, China has been the most active investor in the region, with that country's financing and joint projects for infrastructure development fitting squarely within the “One Belt, One Road” framework of its foreign economic policy. In May 2023 alone, a flurry of bilateral energy-sector agreements was concluded on the sidelines of the inaugural China–Central Asia Summit.

China–Central Asia Summit. In what many observers viewed as a counterpoint to the Group of 7 (G7) annual meeting of major democratic industrialized nations held in Hiroshima, Japan on 19–21 May 2023, the People's Republic of China hosted an inaugural “China–Central Asia Summit” in Xian, on 18–19 May 2023. The Summit, the first in what are planned to be regular biennial meetings,[38] appears to represent an effort by China to more closely coordinate its development strategies with those of the Central Asian states as well as to burnish its international credentials as a reliable diplomatic and trade partner. The areas of planned coordination are diverse, ranging from law enforcement, security, and defense cooperation to the upgrading of bilateral investment agreements (including in energy) and increasing cross-border trade and international transit traffic.

On 19 May—the concluding day of the Summit devoted to a grand assemblage of the national delegations (each headed by the respective countries' presidents) and a press conference—China's President Xi Jinping pledged that Beijing would provide the Central Asian states with financial support and grants worth 26 billion yuan (about $3.72 billion).[39] Among the more notable developments in energy-sector cooperation were remarks by Xi that the building of Line D of the Central Asia–China natural gas pipeline should be accelerated, and a call for China and Central Asia to increase their oil and gas trade, develop cooperation across energy-sector supply chains, and boost collaboration in renewable energy development and the peaceful use of nuclear energy.[40]

Kazakhstan. The opening day of the Summit (18 May) was devoted to a series of bilateral investment talks between China and each of the five Central Asian states. The most active bilateral discussions centered on Kazakhstan, China's most important trading partner in the region. The volume of bilateral trade between the two countries hit a record high of $31 billion in 2022 (44% of total China–Central Asia trade of $70 billion in that year). As a result of their bilateral discussions on 18 May, Kazakhstan and China signed 47 economic agreements worth a total of $22 billion.[41] A key

38 Kazakhstan is scheduled to host the next Summit in 2025.

39 China's estimated cumulative investment in the region prior to the announcement was approximately $15 billion (*Vedomosti*, 19 May 2023).

40 Andrew Hayley, “China's Xi Unveils Grand Development Plan for Central Asia,” Reuters, 19 May 2023; https://www.reuters.com/world/asia-pacific/chinas-xi-calls-stable-secure-central-asia-2023-05-19/; http://mv.china-embassy.gov.cn/eng/zgyw/202305/t20230519_11080116.htm.

41 https://astanatimes.com/2023/05/kazakhstan-and-china-sign-47-agreements-worth-22-billion-as-tokayev-outlines-key-areas-for-partnership/.

emphasis remains the oil and gas industry, which has been the foundation for bilateral relations for many years. More specifically, the following agreements were signed in the sector:

- Expansion of the capacity of certain sections (Atyrau-Kenkiyak [from 6 to 12 MMt/y] and Kenkiyak-Kumkol [from 10 to 15 MMt/y]) of the Kazakhstan-China oil pipeline to boost oil exports (between KazMunayGas [KMG] and China National Petroleum Corporation [CNPC]; $200 million).[42]
- Expansion of Kazakhstan's gas processing capacity, including a feasibility study on the construction of a gas processing plant at the Kashagan field with a capacity of 4 Bcm/y[43] (between the Samruk-Kazyna national wealth fund and CNPC).
- Construction of a second string (15 Bcm/y) of the Beyneu-Bozoy-Shymkent (BBS) gas pipeline, linking western Kazakhstan's gas fields with the Central Asia–China Gas Pipeline [CAGP]; (between JSC QazaqGaz and CNPC).
- Growth of cooperation in the field of natural gas exploration (including at promising new tracts) and field development (QazaqGaz and CNPC).[44] As part of the cooperation agreement, QazaqGaz and CNPC have pledged to: (a) sign a (new) natural gas purchase and sales agreement based on the resource base and throughput capacity of QazaqGaz's gas pipelines and (b) to share scientific, technical, and research expertise to develop technological innovations in the gas industry.
- Cooperation in upstream oil and gas exploration (KMG and Sinopec International Energy Investment Limited) at 17 locations in Kazakhstan. Should deposits at any of these locations prove to be prospective, the parties will consider a possibility of licensing for field development and production.[45]
- Entry of China's Sinopec into the second phase of development of the Atyrau integrated gas-chemical complex (1.25 MMt/y polyethylene plant). The parties (KMG and China Petroleum & Chemical Corporation [Sinopec]) agreed to the joint implementation of a project to produce polyethylene in the Atyrau region (Karabatan), with Sinopec joining the project as a full-fledged partner on par with SIBUR (the Russian petrochemical group currently holding a 40% ownership stake). The project participants are expected to make a final investment decision in 2024.
- Construction of a 1 GW wind farm in the Zhambyl Oblast (Kazakhstan National Wealth Fund Samruk-Kazyna, the Kazakh Ministry of Energy, China Power International Holding Ltd. (CPIH), and China's SANY Renewable Energy). The project reportedly will increase Kazakhstan's total power generation from renewable energy sources by 40%. In addition, CPIH will participate in the construction of factories in Kazakhstan to produce towers, nacelles, and blades for wind turbines.

In addition to talks on hydrocarbons, a number of discussions were held on possible Chinese investments in developing "clean energy" minerals. More specifically, a joint agreement was announced between KAZ Minerals and the China Nonferrous Metal Industry's Foreign Engineering and Construction Company (NFC) to construct a new copper smelter that would give Kazakhstan the capacity to process the entire volume of copper concentrate produced in the country, increasing the value-added component from the production of this metal and providing an ample supply of this "electrification metal" for future decarbonization efforts. Also, discussions focused on development of Kazakhstan's extensive reserves of lithium and rare-earth metals.

Finally, President Tokayev met with the President of China's Asian Infrastructure Investment Bank (AIIB), Jin Liqun, to discuss plans for the further development of activities in the country.[46] In recent years, Kazakhstan has developed green energy projects with the support of the Bank.

Kyrgyzstan.[47] Bilateral talks between delegations led by Presidents Sadyr Japarov and Xi Jinping resulted in the signing of 25 bilateral agreements worth more than $1 billion across a broad range of activities: financial support; public health; air search and rescue; scientific and technical assistance; trade development; agriculture; cultural exchange; and construction of fertilizer, heavy truck assembly, and waste processing plants.

Documents related to energy cooperation and investment that reference specific projects include:

- An investment agreement between the Ministry of Energy of the Kyrgyz Republic and China Power International Development Limited on the construction of a 1000 MW capacity solar power plant in the Issyk-Kul region (€800 million)
- Declaration of intent on cooperation in the export of electricity from the Kyrgyz Republic to China between Kyrgyzstan's Ministry of Energy and China's TBEA Shandong Luneng Taishan Cable Co., Ltd.

Tajikistan.[48] A meeting between the President of Tajikistan Emomali Rahmon and representatives of more than 40 Chinese investment and trading companies, on 18 May 2023, was devoted to opportunities for Chinese investors in the country, focusing on the hydroelectric sector, mining and metallurgy, building materials production (cement), and the transport sector. Twenty-five cooperation agreements were signed at the end of the negotiations that ranged from joint antiterrorism exercises and cooperation in search and rescue operations for civilian planes to the deepening of trade and economic ties.[49] Although no specific energy-sector agreements were announced at the meeting, Chinese company representatives expressed interest in lithium production and processing, solar battery production, oil and gas extraction and processing, and banking services. However, during

42 *Argus Eurasia Energy*, 18 May 2023, p. 4.

43 See *Kazakhstan Newsline*, 26 April 2023 and *Argus Eurasia Energy*, 8 June 2023.

44 https://www.inform.kz/en/qazaqgaz-cnpc-agree-on-cooperation-in-natural-gas-supplies_a4068693. During bilateral talks, QazaqGaz also signed a similar agreement on joint natural gas exploration with China's Geo-Jade Petroleum Corporation (*Interfax Central Asia & Caucasus Business Weekly*, 23 May 2023).

45 *Interfax Central Asia & Caucasus Business Weekly*, 23 May 2023.

46 https://www.inform.kz/en/kazakh-president-receives-aiib-president_a4068716.

47 https://24.kg/english/265847_Meeting_of_Sadyr_Japarov_with_Xi_Jinping_26_documents_signed/.

48 https://avesta.tj/2023/05/19/prezident-tadzhikistana-vstretilsya-s-predstavitelyami-kompanij-knr/.

49 *Interfax Central Asia & Caucasus Business Weekly*, 23 May 2023.

a separate meeting between Rahmon and AIIB head Jin Liqun, agreement was reached on a $500 million concessionary loan to assist in completing the Rogun Hydroelectric Power Plant (HPP) project.[50]

Turkmenistan.[51] At a meeting on 18 May, delegations led by Chinese President Xi Jinping and Turkmenistan's President Serdar Berdymuhamedov discussed a areas of potential economic cooperation. The discussions centered on joint projects in the field of energy (natural gas), transport and communications, and the chemical, petrochemical, and electric power industries. Delegates discussed the supply of energy resources to international markets, cooperation in the transport and communications sector, and partnership in the railway transport sector. Upon conclusion of the meeting, the parties announced the signing of agreements on customs and border issues, media and communications, and general cooperation between the Democratic Party of Turkmenistan and the Chinese Communist Party.

Uzbekistan.[52] On 18 May, President of the Republic of Uzbekistan Shavkat Mirziyoyev met with President of the People's Republic of China Xi Jinping. In the economic arena, the parties reviewed their cooperation in joint projects in the fields of agriculture, land use, small and medium-sized business activity, infrastructure modernization, medical services, and vocational education; prospects for construction of a China-Kyrgyzstan-Uzbekistan Railway also were discussed. In the energy sector, the focus of talks was investment and technological cooperation in the development of renewable energy in Uzbekistan.

A specific emphasis was on the construction of solar, wind, and hydroelectric power plants and supporting infrastructure for electrification:

- the production of solar electric power equipment (transformers and batteries), including the creation of a high-tech cluster for the production of electrical products based on the processing of copper, lithium, and rare-earth metals
- the potential for deepening cooperation in the production of new-generation cars, in particular, the launch of modern plants for the production of electric and hybrid vehicles.

Uzbek officials later disclosed that the two countries had agreed at the Summit "to create more than 6 GW of new renewable energy sources and new transmission lines and substations worth more than $6 billion."[53] The State Grid Corporation of China, Xian Electric, and TBEA were reported as potential partners in the project.

Concluding remarks. The Summit marks only the latest tranche of investments in a long-standing pattern of Chinese energy investment in Central Asia. The China Development Bank, for instance, has been involved in financial support in such major projects as the three existing gas pipeline strings of the CAGP, the first and second phases of the development of the Galkynysh gas field in Turkmenistan, and a polypropylene plant operated by the Kazakhstan Petrochemical Industries Inc. (KPI) with an annual capacity of 500,000 tons. CNPC has been the operating partner in developing the Bagtiyarlyk gas fields in eastern Turkmenistan and is now a partner in the NCOC consortium operating Kazakhstan's Kashagan offshore mega-project. According to China's Ministry of Commerce, as of the end of March 2023, China's total direct investments (all sectors) in the five Central Asian countries exceeded US $15 billion.[54]

Russia-Central Asia. The Russian Federation has substantial and long-standing economic ties to the Central Asian countries, not least in the form of now legacy (but in many cases still extant) Soviet-era technical standards and energy transportation infrastructure. The focus of much recent Russian investment in the region, particularly since 2022, is on the utilization (or upgrading) of this transportation infrastructure to facilitate deliveries of Russian gas, electricity, and crude oil to consumers in the region and perhaps using their territory to transit energy to more distant markets in China and South Asia.

A good example of this recent focus on Central Asian states as both export markets and transit countries are the trilateral discussions between Russia, Kazakhstan, and Uzbekistan to coordinate gas deliveries, including activities to refurbish natural gas infrastructure (e.g., pipelines, compressor stations) to support more intra-regional and international gas trade (see Chapter 2). Among other things, the talks are designed to (a) facilitate Russian gas exports to Kazakhstan and Uzbekistan via existing natural gas infrastructure (e.g., Soviet-era Central Asia–Center pipeline) and new pipelines in eastern Kazakhstan; (b) make it possible for Russian gas to enter the CAGP for export to China or eventually move southward to Turkmenistan to supply South Asia; (c) free up some domestic gas for Kazakhstan and Uzbekistan to export to China. Although specific plans have not been announced, these projects likely would involve substantial investment from the Russian side (presumably via Gazprom).

Similarly, deliveries of electricity by Russia's Inter RAO to Kyrgyzstan via Kazakhstan began in April 2023. Up to 900 million kWh of power is planned to be exported over the period of the agreement (15 April 2023 through 31 March 2024) between Inter RAO and JSC Electric Stations of Kyrgyzstan. However, Inter RAO representatives observed that even more power could delivered if the transit capacity of Kazakhstan's electricity grid is expanded, potentially rising to a level that would meet Kyrgyzstan's current "unmet" power demand (estimated as 3 billion kWh annually). The parties plan to review delivery schedules "on a regular basis in accordance with the provisions of dispatch control and the rules of the energy markets."[55]

In the case of crude oil, Uzbekistan announced an agreement with Russia's Gazprom Neft to purchase 300,000 tons of oil in 2023, transiting through Kazakhstan. More specifically, Kazakhstan's oil pipeline operator KazTransOil announced plans to ship at least 250,000 tons of transit crude from Russia to Uzbekistan, using the Omsk-Pavlodar-Shymkent pipeline, with loading by rail for the final leg of the journey to Uzbekistan.[56]

50 *Interfax Central Asia & Caucasus Business Weekly*, 23 May 2023.

51 https://www.hronikatm.com/2023/05/ca-cn-summit/?ysclid=lhupqt33rp116413075.

52 https://nuz.uz/politika/1277016-prezident-obsudil-v-siane-organizacziyu-proizvodstva-v-uzbekistane-elektromobilej-i-drugie-sovmestnye-s-kitaem-proekty.html.

53 *Nefte Compass*, Vol. 32, No. 20, 24 May 2023.

54 https://www.newscentralasia.net/2023/05/23/over-1-4-bln-has-been-allocated-by-china-to-support-projects-in-central-asia/.

55 https://tass.com/economy/1605589; see also *Central Asia & Caucasus Business Weekly*, 18 April 2023.

56 *Interfax Central Asia & Caucasus Business Weekly*, 7 March 2023; https://www.gazeta.uz/en/2023/04/27/oil/.

Russia's Lukoil also has been an active partner in joint ventures producing oil and gas in Uzbekistan and oil in Kazakhstan (as well as being a member of the multinational consortia KPO and TCO operating in the latter country). However, the situations at two of the more recently emerging projects—at Dostluk and Zhenis—are emblematic of the new more challenging operating environment for Russian companies in the region in 2023. Dostluk is an offshore oil and gas field in the Caspian in an area claimed by both Turkmenistan and Azerbaijan. Once contested between the two governments, in a major breakthrough on 21 January 2021, a Memorandum of Understanding was signed between the two governments on joint exploration and development of the field's hydrocarbon resources. Lukoil was considered to have the inside track on being named the field operator, but the situation became more complicated in 2022. Although Lukoil was not directly the target of Western sanctions against Russia, reports have surfaced that Azerbaijan and Turkmenistan are considering other potential candidates for field operator, such as the Abu Dhabi National Oil Company, out of concerns that Lukoil's participation in the current environment could complicate efforts to obtain international financing, conduct marketing, and access international oil services.[57] Similarly, before it was abandoned in July 2023 due to drilling a dry well, Lukoil's exploration joint venture with Kazakhstan's KMG at the Zhenis offshore oil field reportedly experienced delays in obtaining parts for a drilling rig.[58]

In the nuclear power space, Russia's Rosatom is interested in participating in the build-out of nuclear power generation in the region. In 2018 Rosatom concluded an agreement in principle with Uzbekistan to construct two VVER-1200 pressurized water reactors in the country (1200 MW capacity each), with project costs estimated in the range of $10–13 billion; anticipated completion would be in 2028. The parties then focused on site selection and design considerations, and in July 2022 the two parties concluded an MOU. However, no FID has yet been announced. Negotiations over costs may be one impediment, but there also may be difficulties stemming from Russia's invasion of Ukraine and possible international sanctions on Rosatom. And even if Rosatom remains unsanctioned, there may be collateral effects (e.g., self-sanctioning by third-party service providers) that may be leading the Uzbek side to await greater clarity on the outcome of the conflict before making a final decision to proceed.[59]

Kazakhstan—a major world producer of uranium concentrate—has announced plans to construct high-capacity (up to 2.8 GW) nuclear power plants on its territory (provisionally within 10 years) and is holding talks both with the International Atomic Energy Agency on provision of support for Kazakhstan's nuclear energy program development as well as representatives from reactor companies of at least four countries (China, France, Russia, and South Korea) interested in bidding on contracts to build the reactors. In addition, small modular reactor technologies are currently being considered as a promising direction for subsequent development of nuclear energy in Kazakhstan.[60]

Azerbaijan-Central Asia. Azerbaijan has a shared history with the Central Asian countries as a former Soviet republic, and shares a common pan-Turkic identity with four of the five Central Asian nations (sans Tajikistan). However, its relations with Turkmenistan have until recently been aggravated by competing territorial claims in the Caspian Sea. Nonetheless, the agreement to jointly develop the Dostluk field (see above) in January 2021 has gone a long way to alleviate tensions and pave the way to greater cooperation. At present, Azerbaijan participates in Central Asian energy development primarily as an alternative transit country (to Russia) for relatively small exports of Kazakh crude via the BTC pipeline and as an outlet for small volumes of Turkmen gas (via a swap arrangement with Iran (see Chapter 2)). However, its national oil company SOCAR has been in talks with Uzbekneftegaz about upstream development and upgrading the Bukhara refinery, and at high-level talks between the Azeri and Tajik presidents, the possibility of Azerbaijan's participation in the development of Tajik gas fields was discussed.[61]

United Arab Emirates-Central Asia. Among other active countries involved in Central Asian energy development, the Mideast Gulf countries, particularly the United Arab Emirates (UAE) stand out. Three UAE companies have been particularly active in the Caspian and Central Asian region in 2023, focusing on maritime oil transportation, renewable power plant construction, and upstream gas exploration and production:

- *Abu Dhabi Ports,* which entered into agreements in early 2023 with (a) KazTransOil to jointly operate the Batumi Oil Terminal and to expand its capacity; and (b) KMG to form the Caspian Integrated Maritime Solutions joint venture to operate a fleet of maritime oil tankers in the Caspian and Black seas and provide offshore oil and gas services (including via special shallow-draft vessels).[62]
- *Masdar,* which in 2023 concluded agreements to construct: (a) three utility-scale solar power plants (900 MW aggregate capacity) in Uzbekistan; (b) 4 GW of renewable power capacity in Azerbaijan (onshore wind and solar; offshore wind; green hydrogen); (c) a 1 GW wind plant in Kazakhstan; and (d) 1 GW of renewable power capacity (including a 200 MW solar plant) in Kyrgyzstan.[63]
- *The Abu Dhabi National Oil Company (ADNOC),* which has been in talks with government officials about participating in future phases of development of Turkmenistan's Galkynysh gas field and in possibly becoming the operator of the offshore Dostluk oil field.

In January 2023, Kazakhstan's national company QazaqGaz also signed memoranda of cooperation with UAE companies (Dragon Oil; Petromal LLP) to implement exploration projects and develop new gas fields, as well as to construct additional gas processing capacity.[64]

57 Energy Intelligence, *Nefte Compass*, 3 May 2022.

58 Energy Intelligence, *Nefte Compass*, 1 March 2023.

59 https://thediplomat.com/2022/12/russia-wants-to-speed-up-joint-nuclear-power-plant-project-in-uzbekistan/.

60 *Kazakhstan Newsline,* 30 December 2022.

61 *Interfax Central Asia & Caucasus Business Weekly,* 11 April 2023 and 23 May 2023.

62 *Interfax Central Asia & Caucasus Business Weekly,* 4 April 2023 and 11 April 2023.

63 Energy Intelligence, *Nefte Compass,* 1 February 2023.

64 *Interfax Central Asia & Caucasus Business Weekly,* 24 January 2023.

3.4 High-Level Takeaways

► In its efforts toward regional energy cooperation and economic integration, Kazakhstan's policymakers must come to terms with the fact that energy prices throughout the value chain, including producer prices and end-user prices, need to increase in order to ensure reliable supplies of crude oil for domestic refineries as well as refined products, commercial gas, and electric power for Kazakh consumers. Artificially low prices disincentivize producers to supply the domestic market and lead to the unauthorized/undocumented outflow of Kazakh energy products (especially in border regions) to neighboring states. Price parity between Kazakhstan and its neighbors will need to be achieved primarily by economic measures, such as open market trading via exchanges or liberalizing exports and imports.

► Accession to the EAEU provides a mechanism whereby Kazakh energy prices can rise to parity with those in fellow EAEU member states (particularly Russia) as part of a general movement toward integrated open markets. Higher energy prices will provide clear benefits by increasing the efficiency of energy consumption (in the process lowering GHG emissions) and reducing unauthorized ("grey") exports to consumers in bordering countries. The government should take steps to reduce the burden of higher prices for particularly vulnerable segments of the population but in general should not seek to disrupt the general upward trajectory.

► Kazakhstan must continue to look for ways to increase its attractiveness as a destination for foreign energy-sector investment and cooperation in an increasingly competitive international environment for scarce global capital resources. Although some conditions such as subsoil geology and geography are relatively fixed, improvements in fiscal and licensing policies nonetheless have the potential to substantially increase the country's attractiveness for energy development, both for such traditional fuels as oil and gas and for new clean-energy projects focused on renewable energy.

► Broad Central Asian cooperation in energy markets and infrastructure to date has been delayed by historical differences over other issues such as water rights and territorial disputes, as well as limited access to project financing. The historical differences are not immutable, and the start of cooperation will create a supportive environment and momentum for broader regional energy cooperation in the future. Similarly, access to financing for joint energy projects should improve over time as the region becomes better known to outside investors. It also may be advisable for countries in the region to consider pooling their own capital resources through the establishment of a Central Asian development bank—or via enhanced cooperation through existing institutions such as the Asian Development Bank's Central Asian Regional Economic Cooperation (CAREC) Program or the Eurasian Development Bank—to support joint projects in energy production and transportation, water management, and related activities.

CHAPTER 4

KAZAKHSTAN'S INITIATIVES REGARDING THE ENERGY TRANSITION AND REDUCING GREENHOUSE GAS EMISSIONS

4. KAZAKHSTAN'S INITIATIVES REGARDING THE ENERGY TRANSITION AND REDUCING GREENHOUSE GAS EMISSIONS

4.1 Key Points

► Since independence, Kazakhstan has made significant progress in aligning its environmental laws with global practices and standards. Kazakhstan's current environmental legislation is intended to provide a pathway to sustainable development, environmental protection, preservation of natural resources, and environmental safety, especially with further refinement.

► Among the Central Asian nations, Kazakhstan has been at the forefront of international efforts to address climate change since the 1990s and has made commitments to the international community to reduce its own carbon emissions. As part of its overall strategy, Kazakhstan has committed to achieving carbon neutrality by 2060. In the medium term, the country's goals under the Paris Agreement include reducing greenhouse gas (GHG) emissions by 15% by 2030 compared to 1990 levels, or 25% contingent upon the availability of international support and financing.

► Kazakhstan is actively working to reduce barriers to foreign investment in renewable energy sources (RES) and other clean-energy technologies. The government is taking steps to improve legislation to create a stable and predictable regulatory environment and to offer a variety of benefits and financial incentives to stimulate investment. Nevertheless, legal uncertainties and financial risks still pose challenges. To improve the investment attractiveness of RES and related technologies, it is important to continue efforts to clarify legislation and establish mechanisms to provide stability and reduce risks for investors. The decarbonization efforts of other countries may suggest new approaches for Kazakhstan on how to address these challenges.

► Mainland China and the EU have comprehensive decarbonization plans encompassing a number of specific programs: the “1 + N” decarbonization framework in the PRC and the “Fit for 55” plan in the EU. The Chinese program relies largely on strong central guidance (state-led capitalism) as the vehicle for moving the economy toward lower carbon emissions, whereas the EU plan is focused heavily on regulation.

► The US approach, in contrast, is less comprehensive and more market-inspired—there is no single decarbonization plan. It is based largely on incentives for adoption of clean energy technologies (tax credits and subsidies) provided in the recently enacted Inflation Reduction Act. Regulation is also important, but it mostly occurs within pre-existing frameworks (e.g., the US Environmental Protection Agency's proposed regulations for GHG emissions in electricity generation, emissions standards for new automobiles, and methane emissions regulations).

► The Russian approach seems to be an opportunistic combination of strategies that leverage existing comparative advantages: abundant natural gas resources that can be exported (or used in the production of grey hydrogen for export) to countries wishing to use less-dirty fuels in power generation (e.g., coal in China); forest management (land use, land-use change, and forestry [LULUCF]) as a carbon emissions offset; and some domestic industry emissions reductions associated with energy efficiency improvements. The latter (efficiency) strategy has now been complicated by restrictions on imports of advanced Western energy technologies (such as gas turbines in power generation) following the invasion of Ukraine.

► Similar to mainland China, the European Union, and the Russian Federation, Kazakhstan has a specific document that serves as a decarbonization roadmap toward attaining its net-zero GHG emissions goal—the Low-Carbon Development Strategy (to 2060), adopted in February 2023. The Low-Carbon Development Strategy outlines specific targets for gross emissions, absorption (LULUCF), and net emissions for the country for key signposts in 2030, 2040, 2050, and 2060. That said, the Strategy is largely a set of *concepts* (on how to get to net zero) rather than an *action plan* as such; it does not really elaborate on how existing programs and agencies fit within the grand plan and will coordinate their activities under its framework. Nonetheless, because Kazakhstan has now established a set of programs and institutions for decarbonization, including both regulatory and incentives-based approaches, there is fairly broad scope for significant progress in emissions reductions.

► For example, Kazakhstan's carbon emission trading system (ETS), introduced as a pilot program in 2013, certainly has the potential to greatly reduce the country's greenhouse gas (GHG) emissions. Such a system quantifies emissions targets and permits emission allowances to be traded among participants, encouraging emitters to adopt cleaner technologies and practices at lowest cost, ultimately leading to a decrease in overall emissions. However, despite already being in its “fifth phase” of development, Kazakhstan's ETS still requires further refinement as its current operation, including carbon price formation, does not really incentivize entities to pursue greener solutions.

► An important participant in the ETS is the electric power sector. Reducing coal use in electric power generation is key for Kazakhstan, as the electric power sector accounts for nearly half of total GHG emissions (about 46%), and over 70% of generation is from coal-fired power plants. Without meaningful progress here, all the other decarbonization strategies in the Low-Carbon Development Strategy probably will be insufficient to bring down emissions substantially. But there is a limit to how far Kazakhstan can realistically shift away from coal in power generation over the near term, particularly in light of energy security considerations.

► Similarly, in industry, the 2021 Environmental Code introduced a number of important initiatives aimed at reducing and mitigating the environmental impact of economic activities, particularly the operations of large industrial enterprises. Currently, efforts are underway to prepare domestic operators for a shift to Best Available Techniques (BAT) principles. According to the Ministry of Ecology and Natural Resources, an integrated technological audit was conducted at 94 enterprises in key industries as part of the transition towards the BAT principles by the end of the August 2023. For the 50 largest emitters during 2021-23, 16 industry-specific BAT reference books were developed. There are plans to develop 14 more BAT reference books during 2024-27.

► Despite the active promotion of a low-carbon policy in Kazakhstan, the number of actual projects for the production of clean-energy products remains limited. The largest proposal to date is the project for the production of green hydrogen in Mangystau Oblast, which may nonetheless face the problem of limited water resources in the region and high transportation cost within the overall value chain. Among companies in the energy sector, KMG perhaps is taking the most active steps. The company is trying to explore opportunities to reduce its carbon footprint through projects such as hydrogen development and carbon capture, utilization, and storage (CCUS). Another area with signs of activity is in electric vehicles. With increasing demand for electric cars, the market for large- and small-scale assembly of electric vehicles in Kazakhstan is actively developing with the involvement of large Chinese players.

► Government support for reducing carbon emissions is crucial for achieving climate targets and transitioning to sustainable development. To attain the long-term objective of decarbonizing the economy and meeting climate targets, the state must implement tangible support measures that complement the adoption of legislative acts. While legislation is crucial, the effective execution of specific actions is essential for the energy sector's successful transformation and overall reduction of GHG emissions.

4.2 Overview of Kazakhstan's Environmental Legislation and Policies

4.2.1 Overview of relevant laws and regulations, including the Environmental Code

Kazakhstan's environmental legislation is intended to be a significant contributor to sustainable development, environmental protection, preservation of natural resources, and environmental safety. Kazakhstan's environmental legislation has its roots in the Soviet era. However, after gaining independence in 1991, the country began to develop its own environmental laws to address its unique circumstances and interests. Consequently, the Republic of Kazakhstan enacted the law "On Environmental Protection" in 1997, which served as the primary legislation governing the environment.[1] The law laid out the key principles of environmental protection, the roles and responsibilities of the government, businesses, and citizens, and also defined penalties for violating environmental regulations.

Kazakhstan has made significant progress in aligning its environmental laws with global practices and standards. These laws aim to safeguard the quality of air, water, and soil by controlling pollutants, managing waste, and promoting recycling. They also protect natural habitats, including national parks and reserves, regulate the use of natural resources, preserve biodiversity, endangered animals and plant species, mitigate climate change, and promote eco-friendly behavior among individuals and communities. These efforts demonstrate Kazakhstan's commitment to preserving its environment for future generations.

The government's executive power plays a crucial role in developing and implementing environmental laws. Regular updates and improvements to these laws are necessary to address new environmental challenges and enhance environmental protection. In 2007, the first Environmental Code of the Republic of Kazakhstan (also known as the Ecology Code) was introduced to strengthen legal regulation in environmental protection and nature management. The Code is the primary legislative act that comprehensively addresses environmental concerns. However, certain provisions proved to be ineffective. To modernize infrastructure, increase energy efficiency, and improve the overall environmental situation in the country, a new ***Environmental Code was adopted on 2 January 2021.*** This is another positive step towards protecting the environment and ensuring a sustainable future.[2]

Along with the Environmental Code, Kazakhstan's environmental policy encompasses myriad supporting documents and regulations:

- In February 2023, ***Kazakhstan adopted its Low-Carbon Development Strategy,*** pledging to reach net-zero carbon emissions by 2060. The strategy takes into account global climate trends and international obligations, and outlines a set of concepts and goals for state environmental policy. The goal is to gradually transform the economy to ensure sustainable economic growth, social progress, and well-being. The strategy prioritizes the adaptation of Kazakhstan's economy to global climate trends, focusing on measures such as promoting ESG principles, attracting "green" investments, developing energy-efficient production, promoting electrification, and other environmentally friendly solutions. These actions will pave the way for a "greener" and more sustainable future for Kazakhstan.[3]
- In 2013, Kazakhstan put forward two important documents —***the Development Strategy until 2050*** and ***the Concept for the Transition to a "Green Economy."*** These documents lay down the groundwork for implementing significant changes that will help the country transition to a "greener" economy, while minimizing the negative impact on the environment. The goal is to reduce the energy intensity of GDP by 50% by 2050, compared to 2008 levels, and increase the use of alternative sources of electricity to 50% by 2050. These documents provide a roadmap for reducing GHG emissions in the energy sector, while promoting energy efficiency and conservation. There is also a focus on sustainable transportation, creating infrastructure for electric and gas-

1 Kazakhstan's Law "On Environmental Protection," dated 15 July 1997, is no longer valid, as it has been replaced by Kazakhstan's Environmental Code, dated 9 January 2007.

2 See Section 2.6 in *The National Energy Report 2021*; and S&P Global Commodity Insights, *Lots of Sticks and Few Carrots: BAT implementation in the energy sector within Kazakhstan's new Ecology Code,* November 2021.

3 The Strategy involves investing $610 billion in low-carbon technologies, which will include $10 billion by 2030, with the remaining $600 billion to be invested by the end of 2060.

fired vehicles, managing municipal waste sustainably, adopting sustainable land use methods, and developing organic agriculture.

- Kazakhstan undertook an ***Intended Nationally Determined Contribution (INDC)*** as part of its compliance with the 2015 Paris Climate Agreement. The goal of the INDC is to achieve an unconditional target of reducing GHG emissions by 15% economy-wide by 2030, compared to 1990 (or a conditional target of 25% below the 1990 level by 2030).[4] In 2023, the Ministry of Ecology and Natural Resources updated the INDC by adding a new chapter on adaptation to climate change.
- On 15 July 2022, the Government of Kazakhstan approved ***the Investment Policy Concept until 2026.*** This policy aims to adhere to fundamental principles such as transitioning to "green" growth, promoting the development of sustainable and "green" financing instruments, and implementing ESG principles.
- Chapter 20 of the Environmental Code outlines regulations for controlling GHG emissions, including a market-based approach for the ***Emission Trading System (ETS)***. This system covers approximately half of the country's carbon emissions and is a crucial platform for meeting the objectives of the Paris Agreement and Kazakhstan's environmental goals by 2060.[5]
- ***The Code "On Subsoil and Subsoil Use"*** was put into effect on 27 December 2017. This Code sets forth guidelines for the use of the subsoil, outlines the state's management and regulation procedures in this field, and establishes the legal status of subsoil users and their operations. Additionally, the Code addresses concerns surrounding the transfer of subsoil use rights. Environmental safety is a critical factor in the rational management of the subsoil according to the Code.
- ***The Land Code,*** which was enacted on 20 June 2003, is grounded on the values of safeguarding and rationalizing the use of land resources, along with ensuring environmental security. Its main objective is to avoid any damage to the land as a natural asset caused by entities involved in land use.
- ***The Forest Code,*** enacted on 8 July 2003, sets guidelines for public interactions regarding the ownership, utilization, and disposal of forest resources. This legislation also provides a legal framework for protection, conservation, restoration, and efficient use of forest resources. It is worth noting that forest legal relations are regulated with particular emphasis on the forest's role as a vital component of the biosphere, which has significant ecological, social, and economic implications on a global scale.
- ***The Water Code,*** enacted on 9 July 2003, aims to ensure the responsible and sustainable use of water resources. Its goal is to enhance the quality of life of people and the environment. Currently, a draft of a new Water Code is being developed in Kazakhstan with the aim of introducing system standards that encourage efficient water consumption by individuals, farmers, and enterprises, and incentivize closed-cycle water use and treatment by enterprises and households.
- ***The Law "On Support for the Use of Renewable Energy Sources"*** was enacted on 4 July 2009. This law outlines the objectives, strategies, and approaches for promoting the utilization of renewable energy sources. Furthermore, it establishes guidelines and systems for managing energy waste and utilizing secondary energy resources.
- ***The Law on "Energy Saving and Increase of Energy Efficiency,"*** dated 13 January 2012, outlines the legal, economic, and organizational principles that govern the actions of individuals and organizations with regards to energy conservation and efficiency.
- ***The Law "On Specially Protected Natural Areas,"*** passed on 7 July 2006, governs all matters related to the formation, expansion, protection, sustainable use, and administration of specially protected natural territories and objects within the State Nature Reserve Fund. These areas and objects hold significant ecological, scientific, historical, and cultural value, and are a vital component of the national, regional, and global ecological network.
- ***The Law on "On Protection, Reproduction and Use of the Animal World,"*** from 9 July 2004, manages issues concerning the protection, reproduction, and use of wildlife. Its objective is to facilitate the preservation of wildlife and biotic diversity, while also ensuring the sustainable utilization of wildlife resources to fulfill human needs, both environmental and economic.
- ***The Law on "Compulsory Environmental Insurance,"*** which was enacted on 13 December 2005, governs the public relations that arise in the realm of mandatory environmental insurance. It also sets forth the legal, economic, and organizational principles for its implementation.

Kazakhstan thus has in place *a broad complement of programs and institutions* to help drive decarbonization. The challenge arises in ensuring *the effective coordination of these various programs and the creation of viable regulations and financial incentives.*

4.2.2 Overview of restrictions and barriers to foreign investment in green energy technologies

Kazakhstan has made a strong commitment to renewable energy, following global best practices. This is evident in the country's legislative framework. For example, the Concept for the Transition to a "Green Economy" sets a goal of increasing the proportion of renewable energy in electricity production from 4.5% in 2022 to 15% by 2030, and ultimately 50% by 2050. The Strategic Development Plan until 2025 targets a 6% share of renewable energy in the country's energy balance by 2025.

The Government of Kazakhstan has implemented several important measures to support investors in renewable energy development. These measures include:

- guaranteed purchase of renewable energy at the prices bid at auctions for 20 years through a power purchase agreement

4 The conditional target is contingent upon Kazakhstan receiving additional international investments and "green" climate funds, technology transfer of low-carbon technologies, and additional flexibility owing to its status as an "economy in transition."

5 See Section 4.4.

- an increase in the renewable energy tariff's indexation rate from 70% to 100% in relation to the exchange rate of the tenge to the US dollar
- an exemption for renewable energy producers for paying for electricity transmission
- an exemption for renewable energy producers from the financial responsibility to settle any grid imbalances from their activities, settled instead by the Financial Settlement Center (although this no longer applies to new projects)[6]
- priority dispatch for renewable energy in electricity transmission
- land plots and access points to the network are assured through the broader auction process for renewable energy projects.

Furthermore, renewable energy projects have been included in the list of priority investment projects. This grants them certain benefits such as exemption from customs duties and VAT on imports, and exemption from property tax, land tax, and corporate income tax.

The Law "On Support for the Use of Renewable Energy Sources" underwent amendments and additions in 2017 to introduce an auction mechanism for selecting renewable energy projects. This allows investors to compete on the basis of bid prices for renewable energy projects offered. The auction process ensures transparency, with the winner and project prices determined during the auction. However, due to COVID-2019 and issues such as grid integration, lack of flexible capacity, and outdated traditional generating capacity, the amount of new renewable capacity offered in auctions has decreased. This has likely contributed to the recent decrease in renewable energy investment in Kazakhstan, even as the rest of the world has seen an increase in such investments (see Figure 4.1 Investments in environmental activities related to the "green economy" in Kazakhstan, 2013-21, and Figure 4.2 Global renewable energy investment trends, 2013-22). In 2022, the Ministry of Energy auctioned seven wind projects (wind power plants or WPP), including one with a capacity of 100 MW and six with capacities of 50 MW each; three solar power (SPP) projects, each with a capacity of 20 MW; one 10 MW BioES (biofuels) project; and two hydro (HPP) projects were listed, with capacities of 200 MW and 20 MW.[7] One potential problem is that the small size of Kazakh projects limits the interest of foreign investors (see Figure 4.3 Auctions for renewable energy projects, 2018-23). Larger projects tend to be more cost-effective because of economies of scale: building and operating larger solar or wind projects is often more efficient than having multiple smaller projects. Also, banks and investors also tend to prefer larger projects that offer more stable income streams.

Changes in the underlying legislation may also affect the attractiveness of renewable energy investment. From 1 July 2023, Kazakhstan implemented a centralized system for purchasing and selling electricity. This new system was created to quickly address any imbalances in the energy system, overcome electricity shortages, and promote fair competition. However, some aspects of the new rules might require further calibration. In the past, producers of renewable energy sources (RES) were not responsible for financial costs associated with imbalances in the power grid when they signed long-term contracts for 15-20 years, but new rules make this no longer applicable to new projects. For intermittent renewable energy sources where output can be quite variable, this could be a significant burden.

Still, renewable energy projects do enjoy preferential terms that are not available to other types of power projects. However, the RES build-out in Kazakhstan may have reached a temporary saturation point, owing to the need for grid reliability and a flexible capacity to catch up with increased RES capacity.

Investing in renewable energy projects in Kazakhstan can be a challenge for foreign investors due to the currency risks. Renewable projects require a significant amount of initial capital investment and often involve imported technologies, equipment, and components purchased in foreign currencies. But the primary source of income for renewable energy projects is the sale of electricity in tenge under a long-term contract with the Financial Settlement Center. Although the government of Kazakhstan has implemented an annual indexing of electricity prices in tenge for renewable projects, it may not be sufficient since indexation occurs only once a year on 1 October.[8] Long-term investments in renewable energy projects require income predictability.[9]

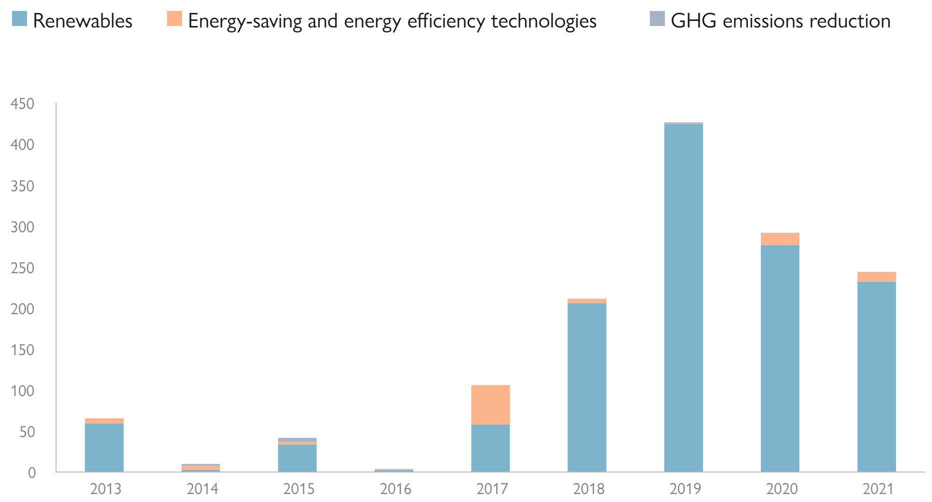
6 Effective 1 July 2023, new RES projects in Kazakhstan will no longer be eligible for this exemption; see https://www.gov.kz/memleket/entities/energo/press/news/details/564150?lang=ru.

7 Both HPP projects in 2022 were not implemented. In the past three years, HPP projects have only taken 10-20% of the capacities on offer.

8 There are two options (formulas) to consider when deciding on annual indexation: (1) based on the consumer price index, or (2) based on the exchange rate. It is important to note that the indexing formula is only selected once when the power purchase agreement is made and is applied throughout the entire duration of the agreement; see https://adilet.zan.kz/rus/docs/P2200000704.

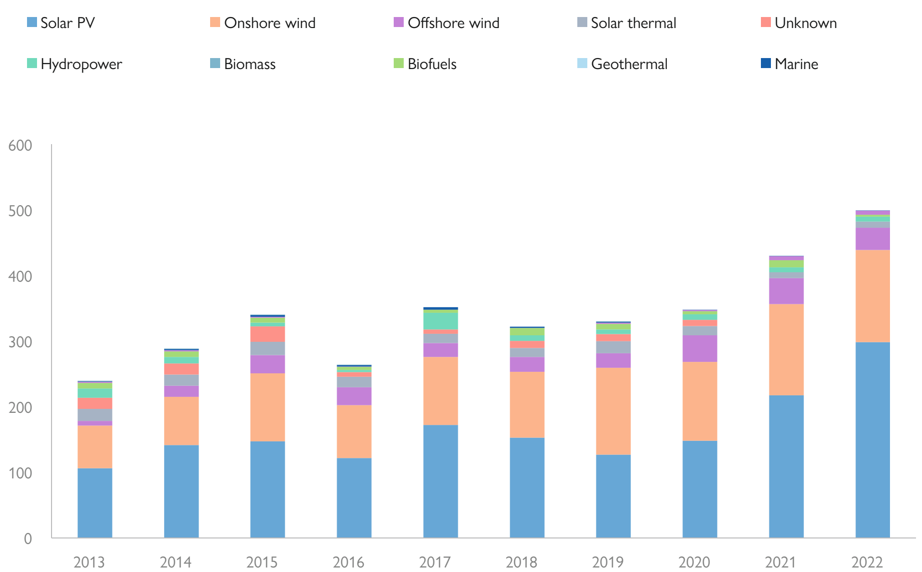
9 An intergovernmental agreement has been signed between Kazakhstan and TotalEnergies for a 1 GW wind project, with a 25-year PPA and presumably a dollar-denominated tariff; https://totalenergies.com/media/news/press-releases/kazakhstan-totalenergies-signs-25-year-ppa-1-gw-wind-project.

Figure 4.1 Investments in environmental activities related to the "green economy" in Kazakhstan, 2013-21 (million US$)



Notes: GHG = greenhouse gas.
Source: S&P Global Commodity Insights, Bureau of National Statistics RK.

Figure 4.2 Global renewable energy investment trends, 2013-22 (billion US$)



Source: S&P Global Commodity Insights, IRENA.

Figure 4.3 Auctions for renewable energy projects, 2018-23 (MW)

Notes: In 2023 auctions are scheduled to take place between August 31 and November 30.
Source: S&P Global Commodity Insights, KOREM.

4.3 National-Level Decarbonization Strategies Differ Widely in Terms of Level of Policy Coordination and Mix of Incentives and Regulations

A review of the decarbonization strategies pursued by four major jurisdictions (in the case of the European Union, a bloc of 27 member-states) reveals considerable diversity in the level of policy coordination and the relative weights assigned to incentives (so-called "carrots") versus mandates ("sticks"). All four have enunciated net-zero carbon goals—by 2050 for the EU and United States, and 2060 for mainland China (People's Republic of China or PRC) and Russia. How they are moving to attain this objective, however, differs widely:

- Mainland China and the EU have comprehensive decarbonization plans encompassing a large number of specific programs: the "1+ N" decarbonization framework in the PRC and the "Fit for 55" plan in the EU. The Chinese program relies largely on strong central guidance (state-led capitalism) as the vehicle for moving the economy toward lower carbon emissions, whereas the EU plan is focused heavily on regulation.
- The US approach, in contrast, is less comprehensive and more market-inspired—there is no single decarbonization plan. It is based largely on incentives for adoption of clean energy technologies (tax credits and subsidies) provided in the recently enacted Inflation Reduction Act rather than solely regulation; the latter mostly occurs within pre-existing frameworks—the US Environmental Protection Agency's proposed regulations for greenhouse gas (GHG) emissions in electricity generation, emissions standards for new automobiles, and methane emissions regulations, for example.
- The Russian approach seems to be an opportunistic combination of strategies that leverage existing comparative advantages: abundant natural gas resources that can be exported (or used in the production of grey hydrogen for export) to countries wishing to use less-dirty fuels in power generation (e.g., coal in China); forest management (land use, land-use change, and forestry [LULUCF]) as a carbon emissions offset; and some domestic industry emissions reductions associated with energy efficiency improvements. The latter (efficiency) strategy has now been complicated by recent restrictions on imports of advanced Western energy technologies (such as gas turbines in power generation).

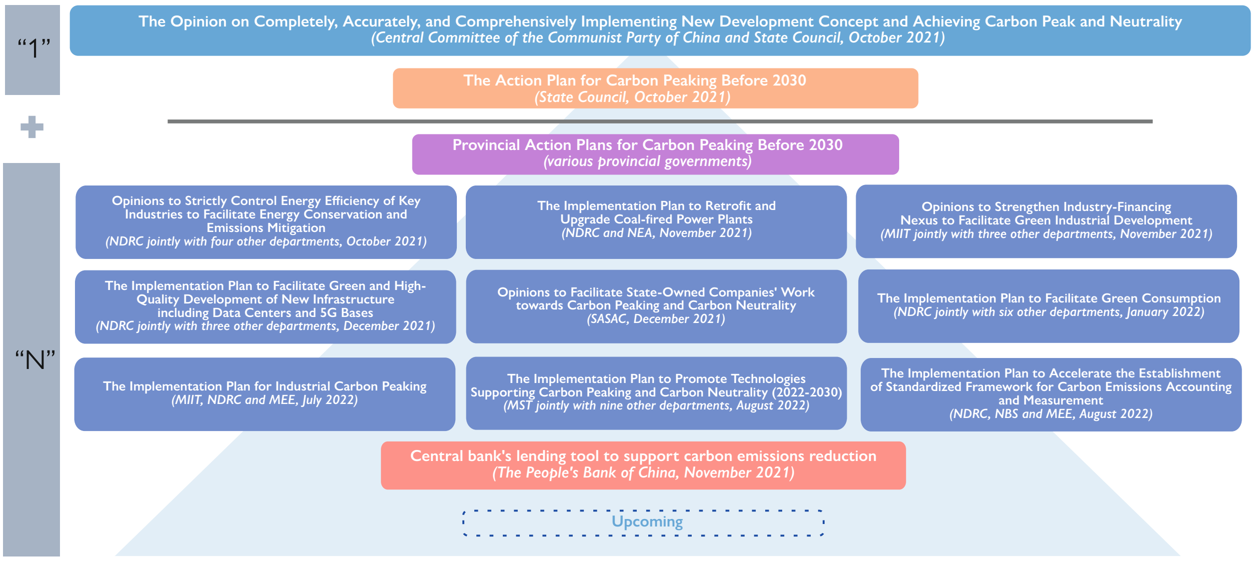
The remainder of this section outlines each of these approaches to decarbonization in the context of their relevance for policymakers in Kazakhstan.

4.3.1 China's "1 + N" policy framework relies strongly on state guidance

Mainland China's "1 + N" policy framework for decarbonization is designed to mobilize resources and coordinate state policy in a centrally directed effort to achieve a medium-term goal along China's ultimate trajectory to net zero in 2060-*to achieve peak carbon emissions before 2030.* China's decarbonization challenge is unique among countries of the world in that it is simultaneously: (a) the world's largest GHG emitter, accounting for 31% of global emissions; (b) the world's largest consumer of coal (more than all other countries in the world combined); and (c) the first country in the world to deploy renewables on a massive scale, building more solar, wind, and other renewable energy capacity than all other countries combined.[10]

10 *New York Times,* 20 July 2023.

Figure 4.4 China's evolving "1 + N" decarbonization policy framework



Notes: NDRC=National Development and Reform Commission; NEA=National Energy Administration; MIIT=Ministry of Industry and Information Technology; NGOA = National Government Offices Administration; SASAC=State-owned Assets Supervision and Administration Commission; MEE=Ministry of Ecology and Environment; MST = Ministry of Science and Technology; NBS = National Bureau of Statistics.
Source: S&P Global Commodity Insights.

The "1" in the "1 + N" framework consists of two national-level documents: (a) the "Opinion on Implementing a New Development Concept and Achieving Carbon Peak and Neutrality," enacted by the Communist Party's Central Committee in October 2021; and (b) "The Action Plan for Carbon Peaking before 2030" adopted by China's State Council in October 2021 (see Figure 4.4 China's evolving "1 + N" decarbonization policy framework).[11] The "N" in the policy framework represents a number of provincial-level plans that target carbon emissions peaking before 2030 through activities as:

- Energy efficiency in key industries
- Green development of new infrastructure, including communication and information technologies such as a 5G buildout and databases
- An industrial carbon peaking plan
- Retrofitting and otherwise updating coal-fired power plants
- Decarbonization of state-owned enterprises (SOEs)
- Adoption of clean-energy technologies
- Enhanced support for green development financing
- Support for the adoption of green products
- Establishment of a standardized framework for emissions measurement and reporting

In addition to the provincial-level initiatives, two other key components in the "1 + N" framework are a ***dedicated Central Bank lending facility*** to finance clean-energy investment and the ***national emissions trading system (ETS)***. Mainland China's national emissions trading system (ETS) is the world's largest compliance carbon market by volumes of emissions covered. Officially launched on 16 July 2021, it is a key decarbonization policy instrument complementing other types of "command-and-control" measures in the "1 + N" framework. Currently only CO_2 emissions from thermal electric power plants are covered in the ETS; they will continue to receive allowances free of charge in the second compliance cycle, which extends two years from 2022 to 2023, covering emissions in 2021 and 2022. After 2023, these free allowances will be gradually reduced based on evaluation of actual emissions, exposing inefficient generators to carbon cost penalties. Power plants at the lower end of the efficiency spectrum most likely will be pushed into operating deficits and eventually could be forced to close. The expansion of the ETS more broadly into the economy, beyond the power generation sector, is likely to be delayed to 2024 or later. Nonetheless, by that time the ETS should begin to play an important role in the movement toward emissions peaking and subsequently reduction.[12]

Three specific goals of the "1 + N" policy framework to 2030 are:

- Increasing the share of non–fossil fuel energy sources (renewables, hydroelectric power, nuclear power) in the primary energy mix to 25%
- Reducing the carbon intensity of economic output to 65% of the 2005 level
- Increasing the aggregate installed capacity of wind and solar power to 1200 GW (from about 760 GW in 2022).

11 S&P Global Commodity Insights, Regional Integrated Event, Tokyo Commodity Markets Insight Forum, *China's Carbon Ambitions: Impact on energy markets*, 4 July 2023.

12 S&P Global Commodity Insights, Global Power and Renewables Profile, Mainland *China Carbon Market Profile*, May 2023.

Reduction of coal use in the electric power, industrial, and residential sectors as well as of oil consumption in the transport sector are key elements in China's emissions reduction strategies for 2030. Coal demand in the residential/commercial and industrial sectors has already peaked in China, and power sector coal use is expected to peak within the next 2–3 years. To meet the need for dispatchable electric power in the national grid, gas-fired generation is planned to expand.

Under the auspices of the "1 + N" framework, S&P Global assesses that China likely will achieve peak carbon emissions on schedule, by 2030, but additional measures will be needed to achieve the 2060 carbon-neutrality target.[13]

4.3.2 The EU's "Fit for 55" policy framework focuses on regulation rather than incentives

The European Union's "Fit for 55" policy framework seeks to organize and coordinate a broad array of climate action programs under the rubric of a more specific clean-energy goal—to deliver a 55% GHG emissions reduction by 2030 (relative to 1990), aimed at generating momentum to put the bloc on track for attaining its net-zero emissions target in 2050.[14] Although both the EU and Chinese frameworks seek to jump-start longer-term climate action by first mobilizing to achieve shorter-term 2030 objectives, the focus of "Fit for 55" is more about establishing effective regulatory frameworks.

Enacted on 14 July 2021, "Fit for 55" will shape EU power, gas, and emerging hydrogen markets through 2030 and beyond. It represents a "doubling down" of already ambitious previous decarbonization goals embodied in the European Green Deal (adopted on 12 December 2019)—the core long-term EU strategy to fight climate change and achieve climate neutrality—by mandating:

- a 50% more stringent emissions reduction target in the carbon market
- a 25% higher mandate for renewable energy use in overall energy consumption
- new mandates to purchase renewable fuels of non-biological origin (RFNBO)
- accelerated energy efficiency improvements
- the extension of carbon pricing to buildings and transport and to importers into the EU of certain products (CBAM).

"Fit for 55" unites five EU programs dedicated to emissions reduction, the renewable energy build-out, and energy efficiency: the EU Emissions Trading System, New Carbon Market, CBAM (Carbon Border Adjustment Mechanism), Renewable Energy Directive II, and Energy Efficiency Directive.

4.3.2.1 Emissions reduction

The emissions reduction programs encompassed by "Fit for 55" include the European Union Emissions Trading System (EU ETS), a new carbon market that will cover emissions from buildings and transportation (New Carbon Market), and the Carbon Border Adjustment Mechanism (CBAM) that will extend EU ETS emissions standards to goods of specified products imported into the EU from non-member countries.

The ***EU ETS***, launched in 2005, involves the acceleration of the original ETS timetable for emissions reduction. Under "Fit for 55," the ETS now envisages a 62% emissions reduction within the system (relative to 2005) by 2030, compared to 43% previously. This is to be achieved by a combination of measures, including:

- Reducing the market cap of free allocations by an equivalent of 5.2% annually from 2024 to 2030, up from 2.2% currently.
- Adding the maritime sector to the market partially from 2024 and fully from 2026.
- Setting a timeline for the expiry of free allocation to installations in key industrial sectors. The electric power, cement, iron and steel, aluminum, hydrogen, ammonia, and fertilizers sectors will start to see a progressive reduction of the number of allowances they receive for free from 2026 (when CBAM takes full effect). By 2030, these sectors will get just over 50% free allocation, and by 2034 free allocation will have ended.

The ***New Carbon Market*** for buildings and road transport (not linked to the EU ETS) will begin operations in 2027. A free emissions allowance (adjusted annually) will be assigned to suppliers of fuel (e.g., gas, diesel, gasoline) to these sectors, who will pay a carbon price for emissions above this allowance. During a pilot phase (2024–27) the free allowance cap will decrease by 5.15% each year, and then by 5.43% annually in the compliance phase that will begin in in 2028. This is designed to provide a soft carbon price ceiling at €45 per metric ton (real 2020), and incorporates a price adjustment mechanism that will allow the release of additional free allowances into the market should the carbon price exceed this ceiling.

The ***Carbon Border Adjustment Mechanism (CBAM),*** described in detail in Chapter 2, went into effect in May 2023. CBAM will impose a fee, starting in 2026, on imports of selected products into the EU commensurate with the degree to which GHG emissions from the production of these products exceeds a specified norm (based on emissions from the 10% of EU companies in the same industry reporting the highest emissions per unit of output). The sectoral coverage includes eight industries—electric power, cement, fertilizers, aluminum, iron-steel, hydrogen, ammonia, and downstream iron-steel products (e.g., screws, bolts, etc. fabricated from iron and steel). The goal is to:

- Encourage countries seeking to export goods to the EU market to adopt the EU's greenhouse-gas (GHG) emissions reduction strategies in the production of those goods
- Protect domestic EU industries from "unfair" competition from imported goods produced without heed for those emissions reduction strategies

13 *China's Carbon Ambitions*, p. 24.

14 Information about "Fit for 55" is largely derived from S&P Global Commodity Insights, Regional Integrated Insight, *"Fit for 55": Final package clarifies path for transformation of Europe's energy mix by 2030,* April 2023.

- Prevent "carbon leakage" from the EU—the re-location of European production volumes to countries with less strict carbon regimes, either as a result of the physical relocation of production capacity outside the EU or by ceding market share to "dirtier" producers as a result of the closure of European capacity.

4.3.2.2 Boosting renewable energy: RED II

The Renewable Energy Directive II (RED II, 2021) program accelerates the timetable for renewable energy build-out from its predecessor (RED I, 2018) by setting an extremely high renewable energy target and providing demand for renewable hydrogen and its derivatives. More specifically, it sets a binding target for renewable energy at 42.5% of total energy in the EU by 2030 (a near-doubling from the recent share of 21.8% in 2021 and fully 10 percentage points higher than the RED I target of 32%), to be achieved through a series of more specific sub-targets in particular sectors of the economy:

- *Buildings:* At least 49% of energy in buildings in the EU must come from renewables.
- *Industry:* 42% of hydrogen used in industry should be produced from renewable fuels of non-biological origin (RFNBO) in 2030, rising to 60% in 2035 (the directive effectively replaces 42% of industry's grey hydrogen demand with green [RFNBO-generated] hydrogen); industry increases overall use of renewable energy by 1.6 percentage points per year.[15]
- *Transportation:* Countries can choose from two options for 2030: (1) a binding target of 14.5% reduction of GHG intensity in transport from use of renewables; or (2) a binding target of over 29% share of renewables in final energy demand in transport. In addition, there is a binding sub-target for advanced biofuels and RFNBO of 5.5% in renewable energy consumed in transport, of which 1% at least must be RFNBO.
- *Biomass in electric power:* Financial support will no longer be available for biomass power plants, unless equipped with carbon capture and storage or located in certain regions.

4.3.2.3 Increasing energy efficiency: EED

The EU's Energy Efficiency Directive (EED, 2012; amended 2018) seeks to complement other elements of "Fit for 55" by specifying rules and obligations for achieving the EU's 2030 energy efficiency targets. It calls for a reduction of final EU energy demand by 11.7% (from 2020) in 2030, which implies a quintupling (fivefold) increase in historical (2005–21) EU efficiency gains, to 2.6% per year to 2030. National contributions will be set by member states; they are indicative and a 2.5% margin is allowed. The directive makes limited proposals as to how this target will be achieved beyond the usual language about the public sector leading by example; specific proposals include the obligation of large energy consumers to implement an energy management system and small and medium-sized enterprises to conduct energy audits.[16] Consequently, delivery of the energy efficiency target is expected to come largely through other EU policy initiatives.

4.3.3 United States: Piecemeal approach relies on new legislative incentives and the existing regulatory framework

Unlike mainland China and the European Union, the United States lacks a single, overarching decarbonization strategy. It instead relies on (a) sweeping new legislation—the Inflation Reduction Act (IRA)—to provide incentives for clean-energy development and (b) changes to the existing emissions regulatory framework (administered by the US Environmental Protection Agency) to reduce greenhouse gas emissions. The United States is now the world's second-largest GHG emitter, accounting for 14% of total global emissions, and plans to reduce emissions by 50%–52% below 2005 levels by 2030, along its projected pathway to net zero emissions by 2050.

4.3.3.1 Inflation Reduction Act

The IRA, enacted on 16 August 2022, earmarks—as part of an estimated massive $433 billion spending package—$386 billion in tax credits and subsidies for renewables and other green energy technologies over a 10-year period. This long window of time is intended to reduce the level of uncertainty among potential investors about whether funding will be available for a sufficient period to ensure the viability of new projects. Among the more noteworthy climate and energy incentives contained in the IRA:

- $161 billion in clean electricity tax credits (e.g., construction of new zero-carbon power generation capacity, conversion of existing capacity, renovation)
- $40 billion in new transportation and infrastructure spending, as well as pollution and hazardous materials mitigation
- $37 billion each for clean-energy incentives for individual citizens and for domestic clean-energy manufacturing —incentives for companies to build solar panels, wind turbines, and batteries and to process clean-energy minerals (e.g., lithium, cobalt, nickel) in the United States
- $36 billion in clean fuel and clean vehicle tax credits, including a $7,500 tax credit for car buyers with income below a certain threshold to purchase a new electric vehicle, and a $4,000 credit for used vehicle purchases[17]
- $35 billion for programs to reduce emissions in the agricultural sector, forest management, and resource conservation (LULUCF)

15 Hydrogen made using nuclear power can be used to meet 20% of the industry RFNBO hydrogen target.

16 https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en.

17 The tax credits are subject to personal income limits on the purchaser ($150,000 taxable income for single filers and $300,000 for joint filers) and domestic content requirements for the vehicles, such as for batteries. They also apply only to passenger sedans with sales prices not exceeding $55,000 and to pickup trucks, vans, and sport-utility vehicles with prices no higher than $80,000 (*New York Times*, 13 August 2022).

- $27 billion to support programs on electrification and energy efficiency in buildings and industry, as well as Department of Energy grants and loans for innovative energy research.[18]

4.3.3.2 Proposed power plant emissions regulations

In tandem with the incentives for clean-energy development contained in the IRA, the administration of US President Joseph Biden is working to revamp the regulatory approach to GHG emissions enforced by the US Environmental Protection Agency (EPA). In the case of power plant emissions this is an approach borne of necessity, after the US Supreme Court in July 2022 struck down the EPA's authority to enforce provisions of the Obama-era Clean Power Plan (2015) mandating the closure of coal-fired power plants. But it has the practical advantage of working within the pre-existing administrative framework for emissions regulation in the country.

The Clean Power Plan had sought to reduce power sector emissions by 32% by 2030 (from 2005 levels), by mandating states submit plans for phasing out coal-fired power generation and increasing renewable generation. The Plan was stayed (temporarily blocked) in 2016 by the Supreme Court to allow a multitude of legal challenges by the states to be heard. In a final 2022 decision on the Clean Power Plan, the Court in effect ruled that the Clean Air Act enacted by Congress (1963, and as subsequently amended) did not clearly delegate to the EPA such broad regulatory authority over the structure (fuel mix) of the power sector.

However, the ruling left intact the EPA's authority to regulate emissions in the sector, so on 11 May 2023 the Agency sought to reduce power sector GHG emissions via a different, more limited mechanism, releasing various emissions reduction targets for power plants based on size, mode of operation (regular or intermittent), and age (e.g., new vs. scheduled for retirement). Rather than identifying specific generation modes for development or termination, it leaves the decision up to operators regarding whether meeting those targets is best achieved through fuel switching or adoption of technologies such as carbon capture, utilization, and storage (CCUS). The EPA does recommend a "best system of emissions reduction" (BSER) for various categories of plants, which in some cases may be carbon capture (coal plants with long future service lives), co-firing with gas (coal plants with intermediate future service lives), or routine operations (natural gas plants, coal plants scheduled for closure).[19] But it no longer seeks to expressly regulate the mode (power source) of generation. Similar to the Clean Power Plan, the proposed new emissions regulations are not guaranteed to take effect: they will also face legal challenges, and there is the possibility of being overturned by the Congressional Review Act pending the results of the 2024 elections in the United States, or some future presidential administration could simply decide to weaken them.

4.3.3.3 New vehicle emissions standards

In the United States, the transportation sector is the leading source of carbon pollution, accounting for 29% of the country's total GHG emissions.[20] Consequently, emissions reduction in this sector will be crucial for any effort by the country to achieve its net-zero goals. In April 2021, the Biden administration and EPA announced new tailpipe emissions standards for new vehicles, with the informal goal of accelerating the adoption of electric vehicles (EVs). The intended effect of the new standards is for 67% of all new light-duty passenger vehicles, 46% of medium-duty delivery vehicles (medium-sized trucks and vans), and one quarter of all heavy trucks sold in the United States to be electric powered by 2032.

The approach followed by the EPA in achieving this objective in effect represents a "lesson learned" from its efforts to transform the electric power industry. Rather than explicitly mandating a switch from fossil fuel–fired internal combustion engines, the Agency instead has opted to tighten tailpipe emissions regulations so strongly that the only way automobile manufacturers can realistically achieve compliance is by switching most of their production to EVs.[21] The EPA is empowered to set limits on the pollution generated by the new vehicles automobile manufacturers produce.

The new rules are set to take effect in 2027. However, similar to electric power regulation efforts, they will face legal challenges. In addition, the sheer scale of industry transformation (plant retooling, worker retraining, supply chain adjustments) will be massive.

4.3.3.4 Methane emissions standards

A third major prong in EPA regulatory efforts to reduce GHG emissions is methane reduction. Methane is a potent greenhouse gas that traps about 80 times as much heat as CO_2, on average, over the first 20 years after reaching the atmosphere, and is believed to be responsible for approximately one-third of the present atmospheric warming from GHGs. Sharp cuts in methane emissions therefore are among the most critical actions available to slow the rate of climate change over the near term. On 11 November 2022, at the COP27 climate summit in Sharm el Sheikh, Egypt, the EPA announced it was strengthening its proposed standards to cut methane and other related pollutants such as volatile organic compounds (VOCs). The stronger standards are intended to reduce methane emissions by 87% below 2005 levels by 2030.[22]

The updated regulations, which supplement proposed standards the EPA released in November 2021 that extended to oil and gas wells nationwide, provide more comprehensive requirements to reduce methane emissions from hundreds of thousands of

18 *New York Times*, 3 August 2022; https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/; https://www.crfb.org/blogs/whats-inflation-reduction-act.

19 For details, see S&P Global, Global Power and Renewables Insight, *US EPA Releases Long-Awaited GHG Regulations for Fossil Fuel–Fired Power Plants*, 12 May 2023.

20 https://www.epa.gov/transportation-air-pollution-and-climate-change/carbon-pollution-transportation#:~:text=%E2%80%8BGreenhouse%20gas%20(GHG)%20emissions,contributor%20of%20U.S.%20GHG%20emissions .

21 In the electric power sector, as noted immediately above in section 4.2.3.2, the US Supreme Court ruled that the EPA did not have the authority to mandate that electric power be produced (or banned) from a specific power source, but upheld its authority to regulate emissions in the sector.

22 https://www.epa.gov/newsreleases/biden-harris-administration-strengthens-proposal-cut-methane-pollution-protect.

Table 4.1 Actual and Net GHG Emissions and Absorption in the Intensive Emissions Scenario, 2019, 2030, and 2050 ($MMtCO_2e$)

	2019	2030	2050	Absolute change, 2019-50
Actual (total) GHG emissions	2,119	2,112	1,830	289
Absorption by LULUCF	-535	-539	-1,200	665
Net GHG emissions	1,584	1,673	630	954

Source: Strategy of Socio-economic Development with low GHG Emissions until 2050, Appendix.

sources nationwide. More specifically, the new rules now apply to all drilling sites, including smaller wells that emit less than 3 tons of methane per year. Small wells currently are subject to an initial inspection but are rarely checked again for leaks. Multiple studies have found that smaller wells produce just 6% of US oil and gas but account for up to half the methane emissions from well sites.[23] The new regulations also would promote the use of advanced methane detection technologies and establish a Super-Emitter Response Program that would leverage data from regulatory agencies or approved third parties with expertise in remote methane detection technology to quickly identify large-scale emissions for prompt control. Although the proposed new standards are subject to review by a variety of stakeholders, oil and gas industry officials have recently been receptive to national-level EPA regulation, preferring a single regulatory framework to a hodgepodge of state-level rules.

In an auxiliary proposal aimed at improving methane leak detection over much of the nation's natural gas transportation and distribution infrastructure, the US Pipeline and Hazardous Materials Safety Administration (PHMSA) on 5 May 2023 announced that was updating old leak detection and repair standards on pipelines, underground storage sites, and LNG facilities.[24] The proposed rule, as mandated under the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020, would deploy pipeline workers across the country to keep more product in the pipe and prevent dangerous accidents. To improve leak detection the proposal calls for using new methane leak detection and repair technologies.

Federal leak detection and repair standards for gas pipelines have remained largely unchanged since the 1970s despite significant improvements in leak detection technology and operator practices over the past five decades. If the new standards go into effect, they are expected to reduce emissions from pipelines by as much as 55%. By 2030, they have the potential to eliminate 1 MMt of methane, which would be the equivalent of 25 MMt of CO_2. The proposed standards are currently under review.

4.3.4 Russian Federation: Limited actions leverage comparative advantages and emphasize carbon offsets

Russia's Nationally Determined Contribution (NDC) to the Paris Climate Agreement pledges a 30% reduction of GHG emissions below 1990 levels by 2030. In October 2021, ahead of the COP26 summit in Edinburgh, Scotland, the Russian government announced a new decarbonization strategy—the "Strategy of Socio-economic Development with low GHG Emissions until 2050"—that includes for the first time a net zero emissions pledge (2060) and more aggressive measures to tackle emissions than previously.[25] The new net-zero target represents a significant departure from Russia's previous plans, which would have seen emissions increase through 2050 and not drop to net-zero until the following century.[26] Under the new strategy, Russia as the world's sixth-largest carbon emitter (after China, the United States, India, the EU, and Indonesia) will endeavor to reduce carbon dioxide emissions by 70% from 1990 levels (and 60% from 2019 levels) by 2050 in an "intensive" scenario that serves as its base case.[27] The new strategy's intensive scenario includes the following major elements:

- A shift of electric power generation away from coal-fired power plants toward gas turbines, nuclear, hydroelectric, and renewable power facilities; for the coal-fired capacity that remains, there will be greater utilization of "clean coal" technologies, including CCUS.[28]
- A moderate, but not decisive turn away from fossil fuel exports to support decarbonization efforts. The new strategy envisions a continued reliance on oil and gas exports, but such exports are expected to decline in real terms at an average annual rate of 2.1% after 2030; the revenue impacts are expected to be mitigated by the export of a higher share of products with greater value-added.[29]

23 https://apnews.com/article/biden-business-prices-oil-and-gas-industry-climate-environment-3a5b7049478ec7161fcbd18f1ebdb0ba.

24 https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair#:~:text=PHMSA%20proposes%20to%20require%20that,leakage%20surveys%20and%20leak%20investigations.

25 The decarbonization strategy was approved by Russian Federation Government Decree No. 3052-R of 29 October 2021, https://www.iea.org/policies/14859-strategy-of-socio-economic-development-of-russia-with-a-low-level-of-greenhouse-gas-emissions-until-2050.

26 https://www.themoscowtimes.com/2021/10/13/russia-aiming-for-carbon-neutrality-by-2060-putin-says-a75284.

27 A second, "inertial" scenario models a business-as-usual approach.

28 It should be noted that such a shift in generation would not represent a particularly dramatic divergence from the present situation, as the share of coal in Russia's recent electric power generation (through 9M 2022) is only 13.8%, compared to 47.1% for gas, 20.1% for nuclear; 18.2% for hydro, and less than 1% each for wind, solar, and "other thermal" (largely mazut). Russia's electricity sector therefore already has a relatively low carbon footprint.

29 Part of the strategy's reliance on exports as part of a decarbonization effort appears to reflect a belief (or hope) that imports by countries of relatively less dirty fuels (e.g., Russian natural gas) potentially at some future date might be counted as carbon offsets to the extent they displace demand for still dirtier fuels (e.g., coal, traditional biomass) in the importing countries. This thinking appears to extend also to the potential development of grey, blue, or green hydrogen exports.

- Increased digitalization and electrification in all sectors of the economy, especially electrification of transportation such as mass transit.
- Increased consumption of hydrogen by industry, especially in metallurgy and chemicals production, and creation of a hydrogen export industry.
- Improvements of energy efficiency in all sectors of the economy; establishment of energy efficiency standards for new construction and renovation of buildings as well as for sectors within industry. The plan calls for an overall reduction in the energy intensity of the economy by half (to the level of "leading countries") by 2050; part of this will be accomplished by structural shifts in the economy in the direction of "post-industrial" sectors, accompanied by an increase in these sectors' share of overall GDP by 11.8 percentage points.
- Implementation of a host of ancillary supporting measures in fiscal policy, Best Available Technologies (BAT) adoption, and clean-energy financial incentives.

But carbon offsets—particularly absorption of carbon in the land use/land use change and forestry (LULCF) sector—are the most important component of the new strategy. Russia's vast forested lands are viewed as the primary resource for climate change action through planned improvements in silvicultural practices (i.e., conversion of unmanaged forests to managed forests), active forestation efforts, and wildfire control. Indeed, Russia's LULUCF sector has been a large emissions sink since the mid-1990s, reaching a maximum of -720 MMtCO$_2$e in 2010 (36% of total non-LULUCF GHG emissions) although subsequently falling to -569 MMtCO$_2$e in 2020, the latest year of inventory data.[30] Under the new plan, the Russian government appears to be relying on an expectation that its researchers, or those in the international community, will be able to provide science-based evidence that current net sinks in LULUCF are greatly underestimated and can substantially and cost effectively be scaled up in the future. Through these mechanisms (re-estimation of the magnitude of its LULUCF sink and the ability to ramp up silvicultural management and reforestation), the strategy to 2050 explicitly targets a more than doubling of LULUCF carbon absorption in Russia, from an estimated 535 MMtCO$_2$e in 2019 to 1,200 MMtCO$_2$e in 2050 (see Table 4.1 Actual and Net GHG Emissions and Absorption in the Intensive Emissions Scenario, 2019, 2030, and 2050). Under this scenario, nearly 70% of the reduction in net GHG emissions in Russia projected by the intensive scenario between 2019 and 2050 (665 MMtCO$_2$e out of 954 MMtCO$_2$e) will come from carbon absorption, with the remaining 30% (289 MMtCO$_2$e) resulting from actual cuts in emissions.[31]

Some analysts, most notably the international organization Climate Tracker, but also including the Moscow-based Center for Energy Efficiency–XXI (CENEf–XXI), have expressed skepticism about whether achieving this level of LULUCF offsets is feasible, given the enormous area of land that would need to be available and how much of it would be suitable for afforestation and improved management.[32] In its base-case scenario, for example, CENEf–XXI projects LULUCF carbon absorption at only 115 MMtCO$_2$e in 2060.[33]

Uncertainties surrounding the broader decarbonization strategy have now been compounded by the onset of open warfare between Russia and Ukraine in February 2022. Western sanctions now greatly impede Russia's access to some advanced technologies used to improve energy efficiency and reduce emissions. As a further consequence of Western sanctions, a key support mechanism for the build-out of renewable generation capacity in Russia introduced in 2021—the Capacity Supply Agreement 2.0 (CSA RES 2.0), whereby domestic and foreign investors bid on long-term contracts to build capacity to deliver electricity at a fixed cost per kilowatt-hour—was suspended in the wholesale and retail markets until April 2023.[34]

Despite the imposition of sanctions, Russia's formal decarbonization goals (as enunciated in the Strategy of Socio-Economic Development with low GHG Emissions until 2050) have so far remained intact. Climate policy is one of the few venues remaining open for dialogue with the West, and by maintaining its climate pledges and remaining in the Paris Climate Agreement Russia can leverage this participation to argue for the relaxation of sanctions on the grounds that this will strengthen its response to climate change. However, much of the momentum toward decarbonization remains jeopardized. For instance, it is no longer clear what will be Russia's path forward in responding to international carbon trading initiatives such as CBAM, which might entail introducing a nationwide emissions trading system and will likely affect its efforts to become a major hydrogen exporter. At present, emissions trading in Russia occurs only in a pilot phase in a single region—Sakhalin Oblast—although a federal law extending emissions trading on an experimental basis to additional regions was enacted in September 2022. Furthermore, the long-term viability of a decarbonization strategy based at least in part on continued natural gas and potential future hydrogen exports now appears to be complicated by both: (a) the long-term downward trend of global demand for natural gas, which peaks around 2040 (Chapter 1); and (b) the current logistical and geopolitical difficulties such exports face as a result of the loss of Russia's former (EU) markets and the reorientation of its energy flows toward the east (Chapters 2, 5, and 6).

4.3.5 Kazakhstan's Low-Carbon Development Strategy to 2060 in comparative perspective

Similar to mainland China, the European Union, and the Russian Federation, Kazakhstan has a specific document that serves as a decarbonization roadmap toward attaining its net-zero GHG emissions goal: the aforementioned Low-Carbon Development Strategy (to 2060), adopted in February 2023. The Low-Carbon

30 https://climateactiontracker.org/countries/russian-federation/.

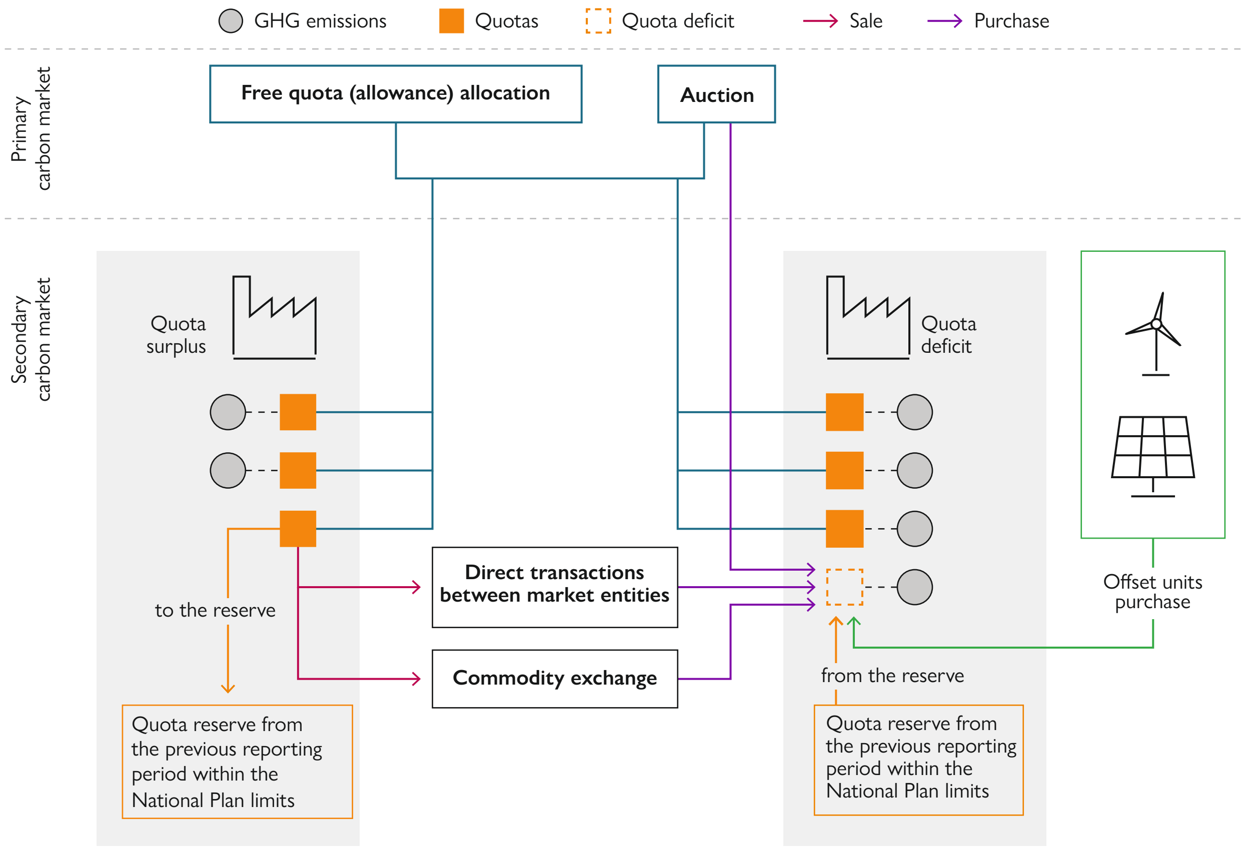
31 These same findings are reported in Center for Energy Efficiency–XXI, *Russia's Carbon Neutrality: Pathways to 2060*, Moscow, June 2022, pp. 27, 112, and Igor Bashmakov, *Russia's Foreign Trade, Economic Growth, and Decarbonisation. Long-term vision,* Moscow: Center for Energy Efficiency–XXI, April 2023, p. 114.

32 Climate Action Tracker is an independent scientific project that tracks government climate action and measures it against the globally agreed Paris Agreement aim of "holding warming well below 2°C, and pursuing efforts to limit warming to 1.5°C." It is a collaboration between two organizations, Climate Analytics and New Climate Institute, and has been providing independent analysis to policymakers since 2009.

33 *Russia's Carbon Neutrality: Pathways to 2060,* pp. 21, 113.

34 S&P Global Commodity Insights, Russia Watch, *Damage Control: How is Russia's energy industry adapting to intensified Western sanctions and new domestic political and economic constraints?* March 2023, p. 52.

Figure 4.5 A schematic illustration of Kazakhstan's ETS



Source: S&P Global Commodity Insights.

Development Strategy outlines specific targets for gross emissions, absorption (LULUCF), and net emissions for the country for key mileposts in 2030, 2040, 2050, and 2060. That said, the Low-Carbon Development Strategy is largely a set of concepts (on how to get to net zero) rather than an action plan as such; it does not really elaborate on how existing programs and agencies fit within the grand plan and will coordinate their activities under its framework. However, this potential shortcoming is mitigated by the fact that Kazakhstan has now established a broad complement of programs and institutions for decarbonization (described in Section 4.2.1), including both regulatory and incentives-based approaches:

- An ETS that now covers roughly half of national GHG emissions
- The Development Strategy until 2050 and the Concept for the Transition to a Green Economy, which set targets for a 50% increase in energy efficiency and increased use of renewable energy (to 50% of the total) by 2050
- Financial incentives for the clean-energy build-out, outlined in the Investment Policy Concept to 2026 and the Law on Support for the Use of Renewable Energy Sources.

The task going forward will be to: (a) ensure the necessary intergovernmental coordination in implementation of these programs; and, within each program, (b) to foster the development of effective regulations and financial incentives. In the following sections of this chapter, we outline some approaches for attaining these goals.

4.4 Improving Kazakhstan's Emissions Trading System

4.4.1 Overview of Kazakhstan's carbon trading scheme

Kazakhstan's carbon trading scheme, known officially as *Sistema torgovli kvotami na vybrosy parnikovykh gazov,* is usually referred to as Kazakhstan's greenhouse gas emissions trading system (ETS). Kazakhstan's ETS is a classic “cap and trade” system that exclusively handles only CO_2 emissions. It is viewed as a key instrument in reducing GHG emissions and eventually achieving carbon neutrality by 2060. Kazakhstan's carbon trading platform was the first to be introduced within Central Asia or even the Commonwealth of Independent States (CIS) when it was launched in 2013. This 2013 scheme was a pilot program. Owing to limited success, policymakers decided to halt the program in 2015, reconfigure it, and then relaunch the ETS in 2018.[35]

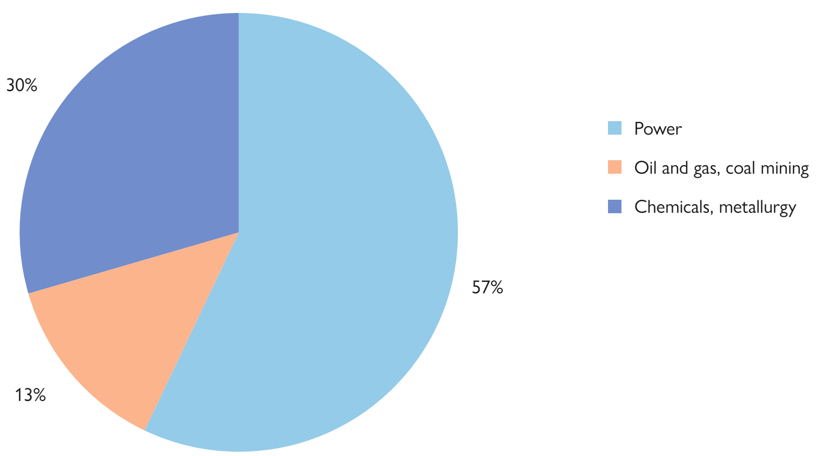
35 Similarly, mainland China's carbon trading system was launched nationally in 2017 after being revamped following an earlier introduction at the regional level; see S&P Global Commodity Insights, China Launches National Carbon Market but with Reduced Scope, December 2017, and S&P Global Commodity Insights, China Releases Basic Framework for Nationwide Carbon Trading, January 2015.

Table 4.2 Phases of Kazakhstan's ETS

	Phase 1 (pilot)	Phase 2		Phase 3	Phase 4	Phase 5			
Year	**2013**	**2014**	**2015**	**2018 - 20**	**2021**	**2022**	**2023**	**2024**	**2025**
GHG covered	CO_2								
Cap ($MMtCO_2$)	147.2	154.9	152.8	485.9*	169.2	166.2	163.7	161.2	158.8
Reserve ($MMtCO_2$)	20.6	18.0	20.5	35.3*	11.5	11.8	11.6	11.5	11.3
Sector coverage	Power generation, oil and gas production, mining, metallurgy, chemicals			Power generation, oil and gas production, mining, metallurgy, chemicals and production of construction materials (cement, lime, gypsum, bricks)					
Thresholds	Technical installation emitting more than 20,000 t CO_2/y (in covered sectors)**								
Allowance allocation	Free allocation***								
Basis for allocation	Grandfathering at 100% of 2010 emissions	Grandfathering at 100% of 2011–12 average emissions	Grandfathering at 98.5% of 2011–12 average emissions	Grandfathering or emission intensity benchmarks	Emission intensity benchmarks (average emission intensity per unit of production by industry)****				

Notes: *The cap and reserves were allocated for the overall compliance period of three years.
**Technical installations with emissions from 10,000 to 19,999 t CO_2/y are subject to administration and not required to participate in ETS.
***Article 291 of Environmental Code allows quotas to be sold on auctions in the amount defined by the National Allowance Allocation Plan.
****Quotas allocated for the period of 2022-25 were calculated by multiplying benchmarks by the average production volumes in 2017-19, considering commitments of GHG emissions reduction by 1.5% annually.
Source: S&P Global Commodity Insights.

Figure 4.6 Phase 1: National Allowance Allocation Plan for 2013



Notes: Total allocation for 2013 was 147.2 $MMtCO_2$; reserve was 20.6 $MMtCO_2$.
Source: S&P Global Commodity Insights.

The legal groundwork for Kazakhstan's ETS began in 2010, and in 2013 a one-year pilot program was launched.[36] The ETS legally operates within the framework of the Environmental Code of the Republic of Kazakhstan.[37] A 100% state-owned joint stock company, Zhasyl Damu, is the market administrator and oversees the ETS. It operates under the purview of the Ministry of Ecology and Natural Resources, which administratively has the legal authority to determine and allocate quotas, grant additional quotas to entities based on capacity additions, manage the quota reserve, and shepherd Kazakhstan's overall GHG emissions reporting to the United Nations Framework Convention on Climate Change (UNFCCC).[38]

Coverage of the scheme currently extends only to power generation, oil and gas production, other mining activity, metallurgy, chemicals, and the production of construction materials (cement, lime, gypsum, and bricks). Any entity operating in these segments with a technical installation (production facility) that emits more than 20,000 metric tons of CO_2 per year (tCO_2/y) is included within the National Allowance Allocation Plan (NAAP) and the ETS scheme.[39] Free allowances/quotas are allocated for these installations based mainly on the

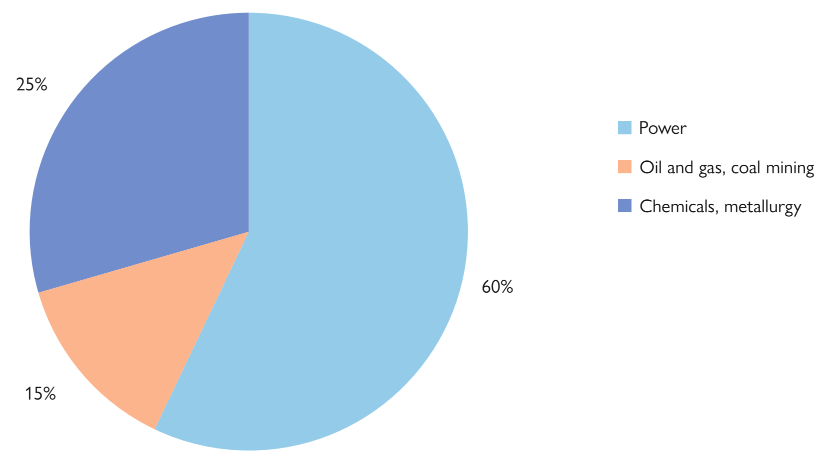
36 See Section 9.3.3.3 in *The National Energy Report 2017*, https://www.kazenergy.com/ru/operation/ned/2117/.

37 See Chapter 20 of the Environmental Code, https://adilet.zan.kz/rus/docs/K2100000400 .

38 See Section 2.7 in The *National Energy Report 2021*, https://www.kazenergy.com/en/operation/ned/2177/.

39 According to Article 290 of the 2021 Environmental Code, the National Allowance Allocation Plan was renamed to become the National Carbon Allowance Plan.

Figure 4.7 Phase 2: National Allowance Allocation Plan for 2014–15



Notes: Total allocation for 2014–15 was 307.7 $MMtCO_2$; reserve was 38.6 $MMtCO_2$.
Source: S&P Global Commodity Insights.

benchmarking method.[40] Many important elements of the operation of the scheme (e.g., allocation and measurement, reporting, and verification) are analogous to those in the EU's ETS. The Kazakh ETS enables enterprises operating in the covered ("regulated") sectors to sell (through the platform or bilaterally) any "spare" allowances that they might have available (resulting from GHG emissions reductions activities), or to buy them in case their emissions exceed their assigned quota, and they face an allowance deficit. Regulated enterprises can also generate carbon units for trading through development of low-carbon projects (see Figure 4.5 A schematic illustration of Kazakhstan's ETS).

4.4.1.1 Kazakhstan's ETS: Phase 1

Since its initial launch in 2013, Kazakhstan's ETS has gone through four phases; currently, it is on its fifth phase of development, which began in 2022 (see Table 4.2 Phases of Kazakhstan's ETS). During 2013, a one-year pilot phase was rolled out. It included 178 major enterprises that ranged across the power sector (55 enterprises with allocations of 84 million metric tons of carbon dioxide [$MMtCO_2$]), oil-gas production, refining and processing, and coal mining (69 enterprises with an allocation of 19.8 $MMtCO_2$), chemicals, and metals mining/metallurgical sectors (54 enterprises with an allocation of 43.4 $MMtCO_2$) (see Figure 4.6 Phase 1: National Allowance Allocation Plan for 2013). In aggregate, these enterprises accounted for 77% of the country's CO_2 emissions and 55% of its GHG emissions in 2010. Under the National Allowance Allocation Plan (NAAP) for 2013, a cap (allowance surrender obligation) was placed on the aggregate GHG emissions of these 178 enterprises that corresponded to their 2010 emissions (147.2 $MMtCO_2$).[41] The general concept was that enterprises that failed to hold their emissions at the 2010 level could purchase allowances from those with credits to spare, or would be subject to fines. Ultimately, however, no fines were imposed on enterprises for non-compliance during the pilot phase. The only penalties imposed were for failure to submit the required documentation and reports.

4.4.1.2 Kazakhstan's ETS: Phase 2

Despite the technical and organizational challenges of the pilot phase, the ETS was extended in 2014 — this time in an operating mode, envisaging penalties for enterprises exceeding the established emissions limits or purchases of additional allowances. According to the NAAP 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% reduction in 2015). The quotas were extended to 60 entities in the power sector with allocations of 184.6 $MMtCO_2$, 66 entities in the oil-gas and coal mining sectors, with allocations of 46.5 $MMtCO_2$, and 40 entities in chemicals and metals mining/metallurgical sectors with allocations of 76.5 $MMtCO_2$ (see Figure 4.7 Phase 2: National Allowance Allocation Plan for 2014–15). Enterprises exceeding their allowances could purchase additional GHG emissions quotas on Kazakhstan's "Caspi" commodity exchange (CCX).[42] A controversial matter at that time involved the issuance by the market administrator (Zhasyl Damu) of additional free allocations to enterprises based on applications received that reflected plans to increase industrial output or to put into operation new emission sources. Concerns

40 According to the Article 300 of the Environmental Code, each installation listed in National Allowance Allocation Plan has a corresponding account created in the State Register of Carbon Units, an electronic transactions tracking system, where carbon quotas are registered and subsequent transactions recorded. All transactions with carbon units (purchases, sale, redemption, removal, acquisition of additional allowances on the basis of increased production, and/or capacity upgrades) are recorded in the State Register.

41 An additional reserve of allowances of 20.6 $MMtCO_2$ was set aside for the expected installation of new capacity (and higher production) at these enterprises in 2013; see National Allowance Allocation Plan for 2013 at https://adilet.zan.kz/rus/docs/P1200001588.

42 Carbon trading on the CCX currently is suspended, as a result of amendments to the Law "On Commodity Exchanges," where Article 13-3 states that from 1 January 2023, only a specially authorized commodity exchange can trade carbon units, https://adilet.zan.kz/eng/docs/Z090000155_. The Ministry of Ecology is reportedly in the process of selecting such a specialized exchange.

were raised about the fairness and transparency of the mechanism for allocating these additional quotas, because not all applicants received additional quotas for their new emission sources.

Questions arose concerning the quotas being traded on the market during Phase 2 (2014–15) when national coal output declined, 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 being sold by enterprises only reflected reduced output (and therefore reduced emissions). Although such sales are clearly prohibited by the Environmental Code, the mechanism for enforcement was inadequate: enterprises registering allowances on the trading platform were not required to report the reason they had allowances available (i.e., the actual causes for their emission reductions). The 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 allowed 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 on 1 January 2016. However, the problems outlined above had not been adequately addressed, and on 26 December 2017 the Government of the Republic of Kazakhstan issued a Decree No. 873 cancelling the National GHG Emission Allowance Allocation Plan for 2016-2020. The decision was intended to give all parties additional time — for the government to make refinements to the system and for the industrial enterprises to make further adjustments and preparations. Although enforcement efforts were suspended, the country's Environmental Code required all enterprises (accounting for roughly 50% of total CO_2 emissions) covered by the ETS' Phase 2 to continue to report their emissions, including emissions of CH_4, N_2O, and PFCs. While only CO_2 has been regulated and traded within the system to date. If additional gases are to be traded and regulated in the future, these should be clearly specified and uniformly defined in legislation.

4.4.1.3 Kazakhstan's ETS: Phase 3

In the 2018 relaunch of the ETS, quotas were granted for the three-year period of 2018–20 (rather than specified as annual caps).[43] Quota use for each company could be dispersed over the three years, but any unused quotas could not be transferred or rolled over to subsequent phases.

With Phase 3, an additional sector was added to the ETS — the production of construction materials (cement, lime, gypsum and bricks). Also starting in 2018, quota allocations were made to specific technical installations rather than to enterprises or entities (see Figure 4.8 Phase 3: National Allowance Allocation Plan for 2018–20). Another important change to the ETS in 2018 was that participants were able to select a mechanism by which their free quota allocations were made: either according to the historical "baseline" method utilized previously or through a benchmarking procedure. The latter, based on a practice in the EU ETS, 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. In a general sense, in the EU system, the 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 receive all of the allowances needed; enterprises that do not would be required to purchase additional allowances to cover their higher emissions. 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 combined heat-and-power plants) or widely varying geologic and field conditions (in the case of coal mining or oil and gas extraction).

In 2021, Kazakhstan adopted 52 of its own benchmarks for specific GHG emissions rates.[44] It appears that benchmarks were calculated on the basis of the average production volumes and emissions of each product in 2013–15. Benchmarking is likely to remain challenging for the power sector, where generation is mainly coal-fired and highly outdated, resulting in a high carbon emissions intensity (CO_2 per kilowatt-hour generated). To reduce its environmental impact (and to improve overall reliability and economic performance), the power sector badly needs general modernization and investment in specific low-carbon technologies. However, government-regulated tariffs make it difficult for generating companies to finance investment and afford such technologies. Given that much of Kazakhstan's generating assets are quite old, a key issue is to develop sufficiently ambitious yet attainable benchmarks for emissions.[45]

Power generating companies have major concerns about the scheduled contraction in their overall emission allowances. They already are struggling with financing modernization, so purchasing additional quotas to cover any excess emissions will lead to additional financial costs that are not covered by current electricity wholesale prices. It appears that to help these companies prepare for the tightening of the ETS quotas, the regulator has set fairly generous benchmarks. For coal-fired electricity generation, for example, the benchmark is 0.985 tCO_2/MWh. For comparison, in 2019, Ekibastuz GRES-1, one of Kazakhstan's largest coal-fired plants (producing about 18% of national electricity output in 2020), had an emission level of 0.925 tCO_2/MWh. Between 2019 and 2021, Ekibastuz GRES-1, through a series of efficiency measures, reduced its emissions to 0.919 tCO_2/MWh in 2020 and 0.904 tCO_2/MWh in 2021, an 8% improvement over three years.[46]

43 See National Allowance Allocation Plan for 2018–20 at https://adilet.zan.kz/rus/docs/P1700000873.

44 Decree of acting Ministry of Ecology and Natural Resources #260 dated 19 July 2021, https://adilet.zan.kz/rus/docs/V2100023621.

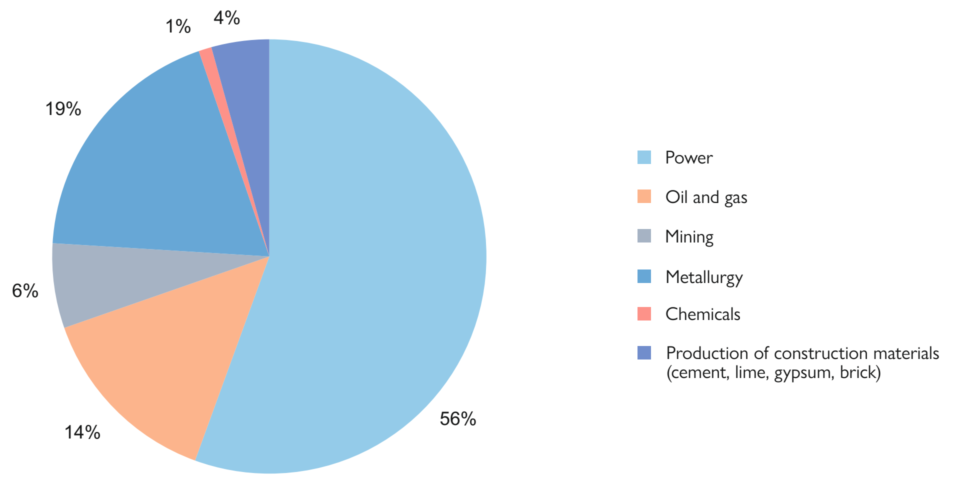
45 See S&P Global Commodity Insights, *Lots of sticks and few carrots: BAT implementation in the energy sector within Kazakhstan's new Ecology Code,* November 2021.

46 See Project of Allowable emission norms of "Ekibastuz GRES-1 after Bulat Nurzhanov" for 2022–25, https://ecoportal.kz/Public/PubHearings/LoadFile/38414 .

4.4.1.4 Kazakhstan's ETS: Phase 4

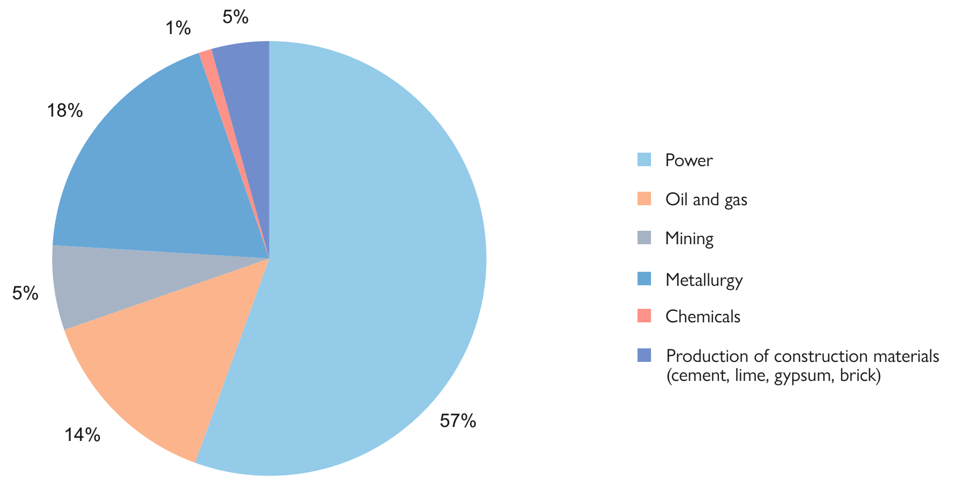
Like the 2013 pilot phase, Phase 4 was in effect only for one year (2021). Quota allocations were made for 218 technical installations and amounted to 169.2 $MMtCO_2$, which was 4.5% higher than the annual average allocation during 2018–20 (see Figure 4.9 Phase 4: National Allowance Allocation Plan for 2021).[47] However, in mining there was a 24.5% reduction year over year. This reflected the fact that in 2018–20, mining companies emitted 30% less CO_2 compared with the initial allocation plan.[48]

Figure 4.8 Phase 3: National Allowance Allocation Plan for 2018–20



Notes: Total allocation for 2018–20 was 485.9 $MMtCO_2$; reserve was 35.3 $MMtCO_2$.
Source: S&P Global Commodity Insights.

Figure 4.9 Phase 4: National Allowance Allocation Plan for 2021

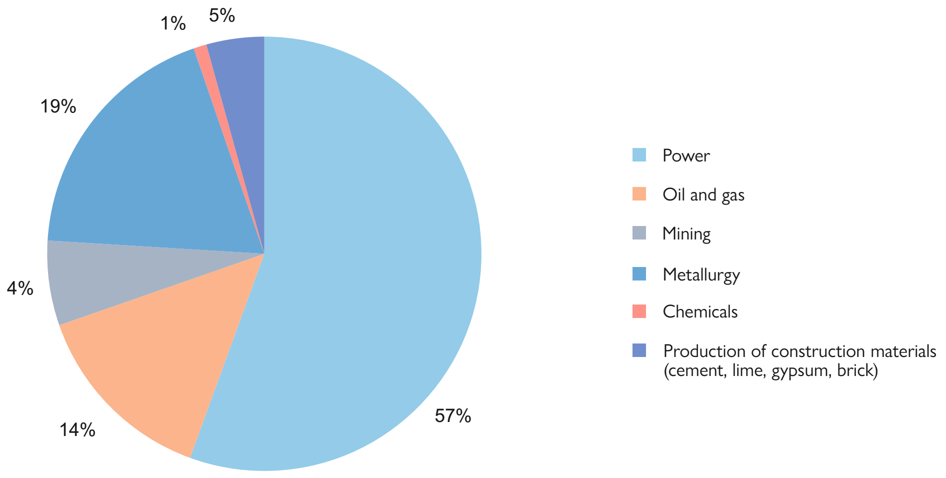


Notes: Allocation for 2021 was 169.2 $MMtCO_2$; reserve was 11.5 $MMtCO_2$.
Source: S&P Global Commodity Insights.

47 See National Allowance Allocation Plan for 2021 at https://adilet.zan.kz/rus/docs/P2100000006.

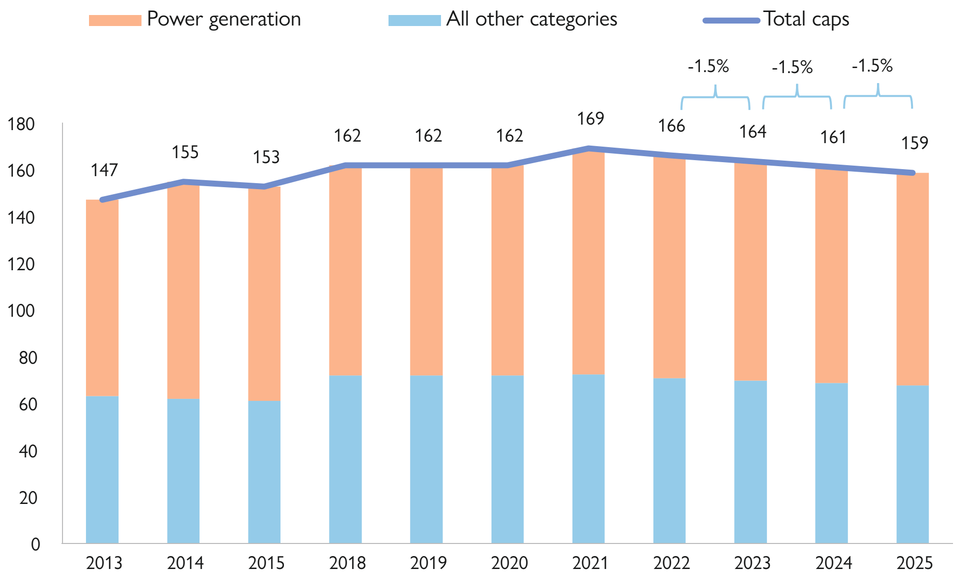
48 For an analysis of Phase 3 emissions data, see Section 2.7 of *The National Energy Report 2021*.

Figure 4.10 Phase 5: National Carbon Allowance Plan for 2022-25



Notes: Allocation for 2022–25 was 649.8 $MMtCO_2$; reserve was 46.2 $MMtCO_2$.
Source: S&P Global Commodity Insights.

Figure 4.11 Kazakhstan's ETS annual caps ($MMtCO_2$)

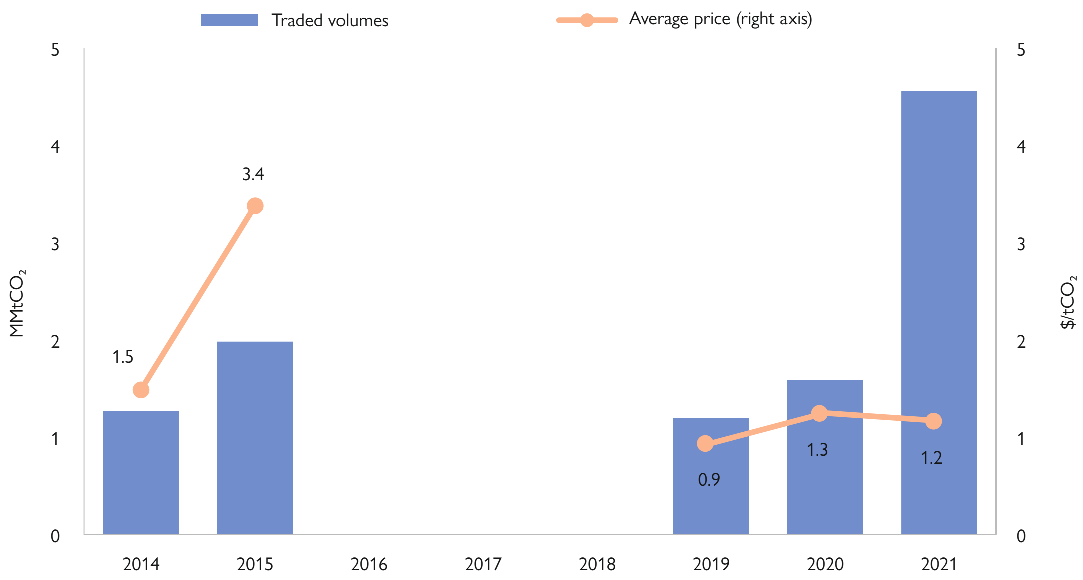


Source: S&P Global Commodity Insights.

4.4.1.5 Kazakhstan's ETS: Phase 5

Phase 5, which spans from 2022 to 2025, maintains the power sector's share of total allowances at a similar level as during the previous phases (at ~56-57%) (see Figure 4.10 Phase 5: National Carbon Allowance Plan for 2022–25). Previously, emissions caps were raised each year, while during Phase 5 there appears to be more of a concerted effort to reduce actual emissions by reducing overall allowances. According to Article 286 of the Environmental Code, an annual linear reduction factor (LRF) in Phase 5 must be no less than 1.5%, which means that annual caps must decrease by at least 1.5% compared to the previous year (see Figure 4.11 Kazakhstan's ETS annual caps). This annual rate for the LRF will also apply to the 2026–30 period.

Figure 4.12 Kazakhstan's ETS secondary market



Notes: $/tCO_2$= US dollars per metric ton of carbon dioxide.
Source: S&P Global Commodity Insights.

4.4.2 A special concern: Market liquidity

As always with these types of trading schemes, a special concern is how to increase liquidity; that is, the volumes and overall aggregate value of total trades. The Environmental Code and State regulation rules for GHG emissions and absorption provide a framework for the operation of the market mechanism of Kazakhstan's ETS.[49] Yet, the small size of Kazakhstan's carbon market alone presents a considerable liquidity challenge, even before considering the existing system's operations and whether the system provides sufficient incentives for participants to trade.

First trades occurred in 2014, when only 1.27 MMtCO_2 were traded, at an average price of 301 tenge ($1.49) per ton, followed in 2015 with 1.98 MMtCO_2 at 830 tenge ($3.38) per ton (see Figure 4.12 Kazakhstan's ETS secondary market). In 2014 and 2015, only 35 and 40 trades were recorded, respectively; prices of the allowances were volatile and not transparent, making it hard for participants to discern meaningful trends. They ended up being much higher for oil and gas producers, ranging between 1,000 and 1,600 tenge per ton ($5.40-$8.91).

As indicated above, the lack of success during the initial stages of ETS led policymakers to halt the program, reconfigure it, and relaunch it in 2018. Still, only three trades occurred in 2019 and six trades in 2020. In 2021, it appears there was a step-change in trading activity (39 trades), not only through CCX, but on other exchanges and through bilateral arrangements, as companies reconciled their emission balances for the 2018–20 period ahead of the August 2021 deadline. Companies that exceeded their emissions quotas in 2018–20 had until 12 August 2021 to compensate through market mechanisms or the direct acquisition of additional quotas, or risk incurring substantial financial penalties.[50] CO_2 prices in the 2019-21 trading period were on the range of $1 per ton, clearly due to low market liquidity. Only about 6.9 MMtCO_2 were traded in 2019–21, which represents 1.4% of the total cap in Phase 3 (2018–20).

In several instances, quotas were bought and sold between different entities directly under bilateral agreements. It appears that market participants informally sought to preserve a carbon price of approximately $1 per ton. Such transactions are not contrary to law, but they undermine the entire market basis of the quota trading mechanism.

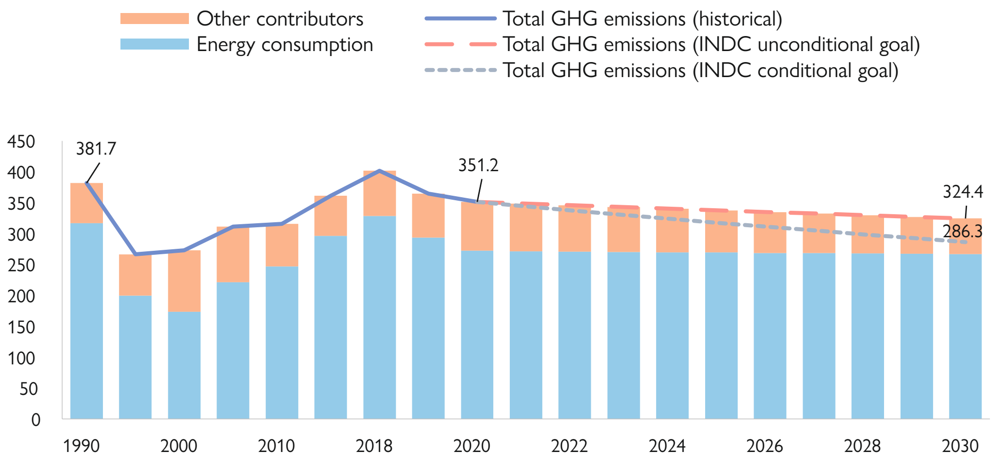
4.4.3 What is needed for Kazakhstan's ETS to become more effective?

Further development of Kazakhstan's ETS could make a significant contribution in achieving Kazakhstan's goal of reducing its carbon emissions and being carbon neutral by 2060. Kazakhstan has been operating its emissions trading system for nearly a decade now, but it currently only covers CO_2 emissions. The system does not regulate other GHGs such as CH_4, N_2O, and PFCs. However, policymakers are considering expanding the system to include these gases, which would increase the overall coverage of GHG emissions in the country from 43% to 61%. Nonetheless, there are still many "unregulated" sectors in the economy that need to be addressed if the goals for reducing GHG emissions are to be met. To achieve these goals, Kazakhstan's Low-Carbon Development Strategy envisions a creation of a Carbon Regulatory System (CRS) that would, among other things, include carbon taxation of installations (processes, goods, and services) whose emissions are not regulated under the national ETS.

49 See https://adilet.zan.kz/rus/docs/V2200027301.

50 The penalty for non-compliance is about $40 (five monthly calculation indexes) per metric ton of CO_2.

Figure 4.13 Outlook for Kazakhstan's GHG emissions: Energy use vs. other contributors (INDC compliant), $MMtCO_2e$



Notes: LULUCF = land use, land use change and forestry.
Other contributors (non-energy use) include industry, agriculture, LULUCF and waste; GHG emissions in 1990 taken from Kazakhstan's 2022 NIR to the UNFCC.
Source: S&P Global Commodity Insights.

To make Kazakhstan's ETS more effective, it is important to decrease the overall cap on allowances over time. This cap determines the maximum volume of emissions allowed and is crucial to the success of other environmental policies. Annual reduction of allowances is necessary to achieve long-term decarbonization goals.[51]

Auctions are the most transparent method for allocating emissions quotas, encouraging participants to consider the environmental impact of their production decisions through application of the "polluter pays" principle. Furthermore, auctions help to establish a carbon price, and the revenues generated can be used to support broad climate protection measures. In the EU ETS, member-states were allowed to auction a certain percentage of allowances in each phase, with approximately 57% of allowances auctioned in the now-completed third phase (2013-20). To date, Kazakhstan's ETS has not used auctions to allocate quotas at all, but it is probably essential to start auctioning at least some proportion of overall allowances, with that proportion increasing over time. Without auctions, there is no transparency in the Kazakh carbon market, and pricing on the secondary market will remain unclear.

The effectiveness of cap-and-trade systems depends heavily on the trading of allowances among companies. When there is a shortage of allowances in the market, those with extra allowances can sell them to those who most need them to comply. Conversely, an excess of allowances effectively halts trading activity and leads to a low carbon price. This situation arose for the EU ETS during its second phase (2008-12); to combat this, policymakers introduced quantity-based interventions, such as the Market Stability Reserve (MSR) and a higher LRF. The MSR manages the number of allowances available in the ETS by absorbing unused allowances and keeping them off the market until needed. Since MSR implementation in Europe in 2018, allowance prices have increased, indicating a growing scarcity. This highlights the importance of flexibility in cap-and-trade systems. The surplus of carbon quotas in Kazakhstan's market can also be effectively addressed by implementing an MSR mechanism. This move can have a positive impact on overall market liquidity, eventually leading to the establishment of a reasonable carbon price in Kazakhstan.

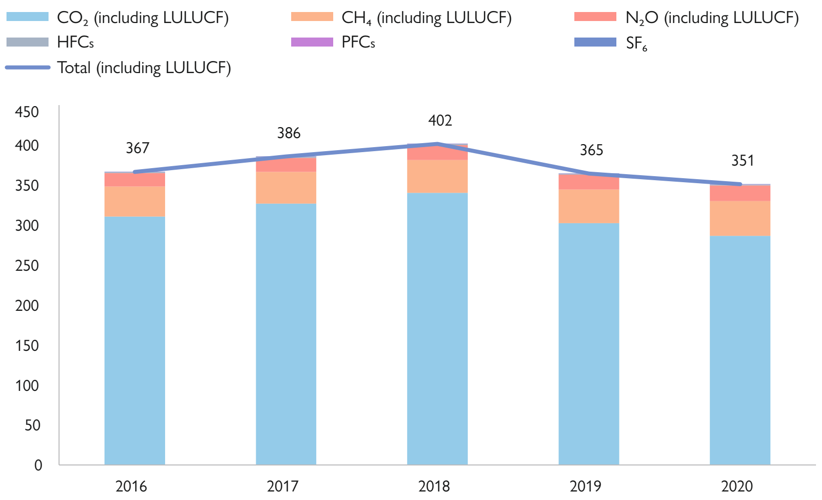
4.5 Analysis of GHG Emission Dynamics: General Trends and Composition

Among the Central Asian nations, Kazakhstan has been at the forefront of international efforts and discussions on GHG emissions since the 1990s and has made commitments to the international community to reduce its own emissions. In 2009, Kazakhstan ratified the Kyoto Protocol, accepting certain emission reduction commitments. Specifically, the Kyoto Protocol called for Kazakhstan to reduce GHG emissions by 15% by 2020 and 25% by 2050 relative to 1992 levels (both voluntary commitments). In 2016, the country joined the 2015 Paris Climate Agreement, renewing its commitments to reduce GHG emissions; and in February 2023, Kazakhstan adopted its low-carbon development strategy, pledging to reach net-zero carbon emissions by 2060.[52]

51 In the EU ETS, the LRF was increased from 1.74% to 2.2% in 2021 and is set to increase to 4.4% in 2028–30. Kazakhstan's ETS, which is younger than its European counterpart, introduced the LRF only recently at 1.5% for the current fifth phase (2022-25).

52 The Strategy was officially approved by the President of Kazakhstan, Kassym-Jomart Tokayev, on 2 February 2023 by Decree No. 121, https://adilet.zan.kz/rus/docs/U2300000121#z67.

Figure 4.14 Kazakhstan's GHG emissions by type, 2016-20 ($MMtCO_2e$)



Source: S&P Global Commodity Insights.

According to the National Inventory Report (NIR) on Kazakhstan's GHG emissions in 2020, published in 2022, total GHG emissions in the country amounted to 351.2 million metric tons of carbon dioxide equivalent ($MMtCO_2e$).[53] To fulfill its unconditional INDC, Kazakhstan needs to reduce its GHG emissions by 57.3 MMt by 2030 from the 1990 level of 381.7 MMt; i.e., to 324.4 MMt of CO_2 equivalent (CO_2e). Hence, achieving the unconditional INDC target requires Kazakhstan to reduce emissions by approximately 3.0 $MMtCO_2e$ on an annual average basis from 2021 to 2030. Achieving the 25% conditional reduction in GHG emissions, to 286.3 $MMtCO_2e$ in 2030, necessitates emissions reductions in the amount of 7.2 $MMtCO_2e$ on average per year during 2021–30 (see Figure 4.13 Outlook for Kazakhstan's GHG emissions: Energy use vs. other contributors (INDC compliant)).

Emissions of CO_2 represented the bulk of Kazakhstan's overall GHG emissions in 2020 (82%), reflecting significant dependence on coal combustion in overall energy use, while emissions of methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) collectively amount to around 18% of Kazakhstan's annual GHG emissions (see Figure 4.14 Kazakhstan's GHG emissions by type, 2016–20).

Examination of GHG emissions by source shows that the energy sector is the main contributor to total emissions in Kazakhstan. In fact, energy activities account for 77% (excluding LULUCF) of all GHG emissions in 2021 (see Figure 4.15 Kazakhstan's historical GHG emissions by sector). This is primarily due to the use of fossil fuels, particularly coal, in power generation. In Kazakhstan, the electric power sector alone accounts for nearly half of total estimated GHG emissions (46.4% in 2022), as around 70% of the electricity generated in the country is produced by coal-fired power plants.

In 2021, agriculture accounted for 13% of total GHG emissions (excluding LULUCF). This is mainly caused by internal fermentation of farm animals, which releases methane, and the cultivation of soils, which emits nitrogen oxide.[54] Methane emissions account for 24.3 $MMtCO_2e$ or 57% of all emissions in the agricultural sector, while nitrogen oxide accounts for 18.5 $MMtCO_2e$ or 43%. GHG emissions from agriculture have been increasing, rising from 30.8 $MMtCO_2e$ in 2013 to 42.8 $MMtCO_2e$ in 2021, due to the growing number of animals and amount of farmed acreage.[55]

Industry contributed 8% or 27.1 $MMtCO_2e$ to GHG emissions in Kazakhstan. This sector releases gases such as CO_2 and CH_4, as well as PFCs, HFCs, and SF_6, which are only emitted by this sector. Metallurgy, which is a larger producer of pig iron, steel, iron ore, ferroalloys, and copper, is the largest contributor to industry emissions, accounting for 55.5% of emissions. The production of construction materials (cement, lime, gypsum, and bricks) is also a significant source of emissions, accounting for 32% of the industrial sector emissions.

Waste and LULUCF contribute 2% and 1%, respectively, to total GHG emissions. In the past two decades, GHG emissions from waste have risen by 78%, due to an increase in the amount of solid household waste produced and the country's growing population. Kazakhstan's LULUCF sector emits more GHG than it absorbs, mainly because of the cultivation of land, which results in higher emissions than forested areas can absorb.

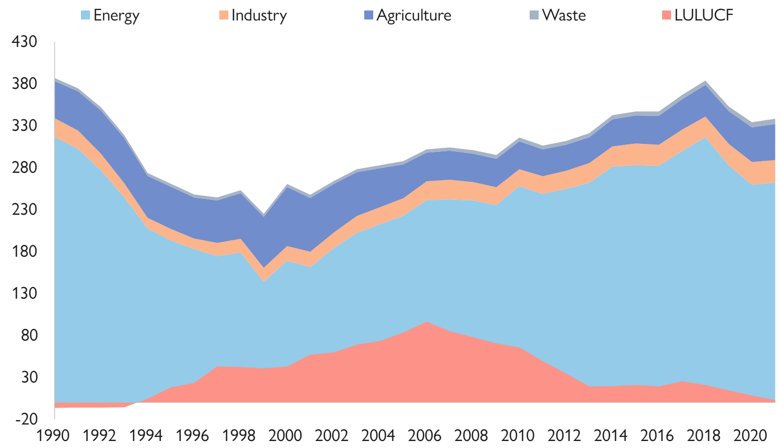
The power sector in Kazakhstan is responsible for the majority of GHG emissions. Coal-fired power plants, which are a major contributor to the country's electricity production, are the primary source of these emissions (see Figure 4.16 Base-case outlook for GHG emissions from energy use in Kazakhstan). To

53 In 2020, GHG emissions from land use, land-use change, and forestry (LULUCF) contributed to an increase in overall emissions total, whereas this category typically acts as an offset against emissions coming from other economic activities.

54 Global warming potential for a 100-year time horizon of CH_4 – 25, N_2O – 298; https://archive.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

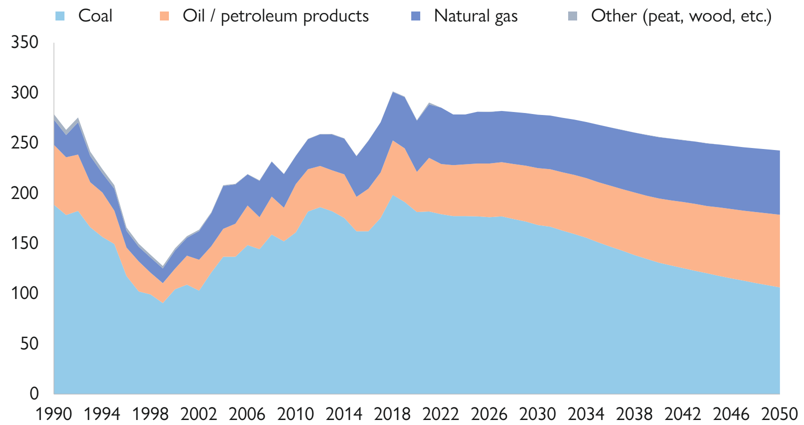
55 According to the Bureau of National Statistics, the population of livestock and poultry in Kazakhstan has grown by 34% between 2013 and 2021; https://stat.gov.kz/ru/industries/business-statistics/stat-forrest-village-hunt-fish/publications/58390/.

Figure 4.15 Kazakhstan's historical GHG emissions by sector ($MMtCO_2e$)



Source: S&P Global Commodity Insights, UNFCCC.

Figure 4.16 Base-case outlook for GHG emissions from energy use in Kazakhstan ($MMtCO_2e$)



Source: S&P Global Commodity Insights.

achieve a notable reduction in GHG emissions nationwide, the energy sector must decarbonize. Or more precisely, reducing coal use in electric power generation is the key to decarbonization for Kazakhstan. Without meaningful progress here, all the other decarbonization strategies in the Low-Carbon Development Strategy will be insufficient to bring down emissions meaningfully. But there is a limit to how far Kazakhstan can realistically shift away from coal in power generation, particularly in light of energy security considerations. Still, Kazakhstan should make every effort to achieve meaningful reductions in coal use.

Power sector decarbonization will necessitate a gradual shift away from coal-based electricity generation toward cleaner energy sources, such as renewables and natural gas.

- **Development of renewable energy sources** is crucial in reducing GHG emissions in the energy sector. Kazakhstan's government has played a significant role in promoting this initiative, leading to a noticeable increase in the use of renewable energy and achieving a 4.5% share of renewable energy in the country's electricity supply. These efforts contribute to diversifying the country's energy portfolio and reducing dependence on fossil fuels. However, it is important to consider the challenges of maintaining stability and balance in the electricity grid. Renewable sources, such as solar and wind energy, are intermittent, subject to fluctuations depending on the weather conditions. This can cause electricity production to vary, which affects the reliability and stability of the power system. Therefore, the development of maneuverable capacities, such as flexible generation (gas-fired power plants) and storage systems (batteries), are essential to ensure the stability of the energy system, particularly during periods of peak demand. A comprehensive approach is necessary for the development of renewable energy, which includes not only increasing the share of renewable energy but also creating a supportive structure of maneuverable capacities.

- **Carbon capture, utilization, and storage (CCUS)** technologies can be a valuable tool in combatting GHG emissions. Governments will need to consider the cost of these technologies when deciding how to proceed. CCUS involves the capture, transport, and utilization of carbon, and its storage in deep geological formations. This can reduce carbon emissions into the atmosphere. Kazakhstan has relied heavily on coal as an energy source due to its abundance in the country, particularly in the north. This has enabled reliable and low-cost electricity for the economy, so moving away from coal will not be easy. Further, CCUS implementation faces challenges such as technical complexity, high infrastructure costs, and ensuring carbon storage safety. Despite these challenges, CCUS presents an alternative way to reduce emissions without completely ending fossil fuel use.

- Reducing GHG emissions can be achieved by **energy-efficient technologies** and projects that improve fuel combustion efficiency. This can lead to a reduction in resource consumption and the amount of carbon emissions released into the atmosphere. Sectors across the economy can benefit from energy-efficient technologies. Upgrading equipment, reducing energy losses during transmission, and effective management and monitoring of systems are all ways to conserve energy. By reducing energy consumption, GHG emissions can be reduced as well. Improving combustion technologies for burning fossil fuels is another strategy to consider. This can lead to greater energy realization from the fuel. These projects, in addition to reducing GHG emissions, can also lower operating costs and increase competitiveness.

- **Managing methane leaks** in the energy sector is a key challenge in reducing greenhouse gas emissions. It means implementing comprehensive measures and innovative technologies to prevent, detect, and repair leaks throughout all stages of oil and gas production, transportation, and refining. To minimize leaks during production, drilling and well operation technologies should be improved. The use of modern monitoring and control systems, such as sensors, can facilitate the quick detection of small leaks and enable their prompt elimination. In the transportation of oil and gas, infrastructure such as pipelines, compressor stations, and storage facilities should be a focus of attention. To prevent methane leaks into the environment, pipeline modernization projects, regular inspection for cracks and corrosion, and the use of monitoring systems are needed.

4.6 State Support for Decarbonization

Government support for reducing carbon emissions is crucial for achieving climate targets and transitioning to more sustainable development. Amid growing concern about climate change, many countries recognize the importance of decreasing greenhouse gas emissions and switching to renewable energy sources. To achieve this goal, governments are developing and implementing various support measures that incentivize companies and investors to participate in decarbonizing the economy.

Thinking about how to incentivize clean-energy investment is important, especially to the extent that the private sector (including foreign investors) will be asked to provide a lot of the up-front capital. Investors need to be confident that initial costs will be recouped over a reasonable period of time. Reliance only on "sticks" (regulations), without any clear path that investors see for returns, will drive away investment. So, it is important for the government to have a plan for how to support clean-energy investment.

The first step in governmental support is **to create and execute national decarbonization strategies and plans.** To reduce greenhouse gas emissions, Kazakhstan has adopted a Strategy of Low-Carbon Development by 2060. The Strategy outlines national approaches and defines the state policy's strategic course for a consistent transformation of the economy to promote well-being, sustainable economic growth, and equitable social progress. One of the three key areas of the Strategy is the decarbonization of industries and processes related to fossil fuels. To reduce emissions, the Strategy suggests measures like transitioning from fossil fuels to renewable energy sources, improving energy efficiency and conservation, and electrification — replacing fuel-burning installations with electricity-based technologies.

The next step of state support is the creation of functional regulatory frameworks and legislation that contribute to the decarbonization of the economy. The government can establish regulations for energy efficiency, greenhouse gas emissions, and carbon trading. These regulations can encourage companies and industries to make appropriate changes and search for innovative solutions. To support the growth of renewable energy, several legislative initiatives have been developed, including tax incentives and other financial benefits. In 2021, Kazakhstan introduced an updated Environmental Code that requires polluters to use the best available technologies in their operations. In addition, Kazakhstan has also launched a system for trading greenhouse gas emissions quotas.

To decarbonize the economy and meet climate targets, the state must implement **tangible support measures that complement the adoption of legislative acts.** While legislation is crucial, the **effective execution of specific actions** is essential for successful transformation and the reduction of GHG emissions.

In order to drive **the adoption of cleaner technologies,** it is essential **to provide financial assistance** for their development and implementation. This can be achieved by offering state-provided subsidies, or loans with favorable terms, or specific kinds of tax relief to companies that are implementing eco-friendly solutions. These measures help to mitigate financial risks and foster innovative ideas in the energy sector.

In Kazakhstan's application of BAT principles as outlined in the Environmental Code, the state's proposal to merely waive environmental fees probably is not sufficient to cover the costs associated with implementing expensive low-carbon technologies. These environmental fees only make up approximately 2% of a company's operational expenses.[56] This is clearly insufficient for successful and sustainable integration of best-available low-carbon technologies. More financial support is needed for their successful implementation.

4.7 Initiatives in Low-Carbon Development

Despite the active promotion of a low-carbon policy, there are not many real initiatives in this field in Kazakhstan. The largest initiative to date is the project for the production of "green hydrogen" in Mangystau Oblast. Among the companies in the energy sector, KMG is among the leaders in activity.

4.7.1 Hydrogen

In 2022 Kazakhstan created the first alliance on hydrogen called "Green Hydrogen" in Kazakhstan at the Astana Finance Days-2022 conference. A year later, in February 2023, Kazakhstan approved the Low-Carbon Development Strategy of Kazakhstan to 2060. In this strategy, hydrogen is assigned a significant role in transforming energy use in transportation and industry, two sectors that are difficult to decarbonize. For example, hydrogen is supposed to be used in those modes of transport that are difficult or impossible to fully electrify, such as water and air transport.

4.7.1.1 "Green" hydrogen production in Mangystau Oblast

In October 2022, the Kazakh government signed an investment agreement with the European renewable energy group Svevind Energy GmbH for the construction of a hydrogen production project in Mangystau Oblast that would rank as one of the five largest projects in the world.[57] The project will use wind and photovoltaic generation with a total capacity of up to 40 GW, generating approximately 120 billion kWh of renewable electricity annually.[58] The electricity will supply an industrial park with a capacity of 20 GW of hydrogen electrolysis, located near the Kuryk port on the Caspian Sea coast.

The Caspian Sea will be the source of water for hydrogen electrolysis, following desalinization. The project is said to include the construction and operation of a desalination plant with a capacity of 255,000 m^3 of seawater per day (93.075 million m^3 per year). But questions surrounding water availability are of paramount importance to Kazakhstan, and the project, and could very well emerge as one of the major obstacles preventing project execution.

Freshwater availability has long been a major problem in Mangystau Oblast. Besides several local desalination plants (e.g., in Aktau, Kalamkas), one of its key sources of fresh water is water piped all the way from the Volga River delta in Russia, a distance of nearly 2,000 km. Reflecting its economic and social importance, the pipeline has been the target of an ongoing refurbishment and modernization program in the last few years to increase its throughput capacity to over 30 million m^3 per year. In 2023, for example, authorities intend to augment fresh water supply with completion of an 18 km water pipeline and water pumping station, financed by a 2.12 billion tenge ($4.7 million) investment by Freedom Holding Corp.[59] Despite this, authorities in Mangystau Oblast still anticipate the region's water deficit will reach 110,000 m^3 per day by 2025.

Hyrasia One, a subsidiary of Svevind Energy Group, indicates that no final decision has been made on specific markets for the hydrogen and therefore export destinations and routes. Svevind believes the hydrogen can find a ready market in Europe or alternatively can be used within Kazakhstan itself to manufacture "green" steel or aluminum. Clearly though, Europe ranks high on the list of potential markets given ambitious plans for hydrogen development there and the expectation that Europe will account for about 11% of global hydrogen demand by 2030 and 20% by 2040; furthermore, a significant share of demand is expected to be met with imports.[60] As noted by Svevind, Hyrasia One could become "a supporting pillar for the hydrogen markets currently emerging in Europe, as well as in Kazakhstan itself and in Asian countries." potentially be reconfigured to carry hydrogen cross Russia first. Transport by rail is technically feasible but would be far more expensive than these other options.

Importing the necessary equipment for the project will likely be challenging as well with the changed international situation. For example, TCO's FGP upstream expansion project relied in large part on Russia's inland waterway system to import large modular components for the megaproject.[61] This transport option may no longer be available following Russia's invasion of Ukraine, which means the project developer may have to use more costly

56 See Section 2.6.2 in *The National Energy Report 2021.*

57 Svevind Energy GmbH, a privately owned group of renewable energy companies based in Germany and Sweden—announced the signing of an initial memorandum of understanding (MOU) with the akimat (provincial administration) of Mangystau Oblast together with state-owned Kazakh Invest National Company to construct 30 GW of wind and solar power generation capacity in Mangystau Oblast, to be used to power electrolyzers to produce "green" hydrogen for domestic use or export; see *The National Energy Report 2021,* p. 52 and S&P Global Commodity Insights, *Ambitious large "green" hydrogen energy project announced for Western Kazakhstan,* November 2022. Svevind Group CEO Wolfgang Kropp and President Tokayev also met in September 2021.

58 The mix of generating capacity is not specified, but this represents a very ambitious capacity utilization factor for renewables of about 34%; typically, onshore wind averages about 25% and solar only about 13%.

59 "Group of companies Freedom will help solve the freshwater deficit problem in Mangystau Oblast," 28 October 2022, https://www.inaktau.kz/news/3487256/gruppa-kompanij-freedom-pomozet-resit-problemu-s-deficitom-presnoj-vody-v-mangistauskoj-oblasti .

60 See the IHS Markit Report *Global Hydrogen Balance: Outlook to 2050,* October 2022.

61 See the IHS Markit Insight, *Russia's Inland Waterways Feel Impact from Tax Maneuver with Reduced Refined Product Shipments.*

multimodal options (i.e., transport by rail across Georgia and Azerbaijan, and then by ship or barge across the Caspian Sea to Kazakhstan).

Hydrogen is not a very transportable product, owing to the relatively high costs involved for transportation within the overall value chain, and this remains true even if hydrogen is transformed into "green" ammonia for long-distance transportation.[62] Logistically, western Kazakhstan fairly remote from Europe and lacks direct access to international sea lanes for transport by ship; furthermore, the only existing gas pipelines from the region that could

4.7.1.2 KMG and other hydrogen initiatives

In 2022, KMG created a new structural unit, the Competence Center for Hydrogen Energy, which is intended to serve as a research hub. The company has designated hydrogen as one of its low-carbon initiatives, establishing the pilot project "Hydrogen Mobility" that will feature the construction of a hydrogen filling station at the Atyrau refinery.[63]

Hydrogen Mobility is not the first KMG initiative in this area. Previously, in 2021, KMG announced its participation in blue hydrogen and blue ammonia projects using natural gas as feedstock in cooperation with the German-based industrial gas and engineering company Linde. The project was subsequently cancelled due to its large water requirements and other technical issues.

The Pavlodar refinery and Air Liquide Munay Tech Gases LLP (ALMTG) also signed an agreement for the construction of a hydrogen production unit for the production of winter diesel fuel (160,000 tons per year) at an estimated cost of 80 million euros.[64] Since 2018, ALMTG has been successfully operating hydrogen and nitrogen production units at the Pavlodar petrochemical plant, and from 2021 at the Atyrau refinery.[65] And in May 2023 ALMTG signed an agreement with KunTech LLP to provide its production facilities in Kazakhstan with renewable energy.[66] The agreement seeks to cover 100% of the electricity consumption at ALMTG production sites, reducing indirect CO_2 emissions by 33% in 2035 compared to 2020, and to achieve carbon neutrality by 2050.

Several other initiatives have been launched on green hydrogen in Kazakhstan over the past couple of years, but have not really moved forward:

- On Astana Finance Days-2022, Green Spark Limited LLP and GRAF Industries S.p.A. signed an agreement on the development of a technology for the first hydrogen filling stations in the territory of Kazakhstan, but the initiative was not further developed.
- First Kazakhstan commissioned a pilot project for the production of green hydrogen in the West Kazakhstan Oblast. The project includes solar panels that power electrolyzers that split water into hydrogen and oxygen. Project development by GreenSpark was launched in 2021, but is still not completed.

4.7.2 CCS/CCUS projects

One of the directions of KMG's Low-Carbon Development Program for 2022-31 is a project to introduce carbon capture and storage technologies. An important step in this direction was the signing in June 2022 of a memorandum of understanding between KMG and Chevron (through its subsidiary Chevron Munaigas Inc.) to explore potential carbon reduction projects in Kazakhstan, with a particular focus on CCUS. A similar agreement on the joint study of CCUS projects was signed in September 2021 between KMG and Shell Kazakhstan b.v. In the Low-Carbon Development Concept of Samruk-Kazyna (KMG's parent company), the implementation of the CCUS at KMG is envisaged in several stages:

- Stage 1 (2022-23): Screening of CO_2 emission sources and injection reservoirs at KMG assets
- Stage 2 (2024-25): Design for the first stage of a CCS/CCUS pilot project at KMG assets
- Stage 3 (2026-28): Implementation of a pilot project on the use of CCS/CCUS technology.[67]

And at the end of 2021, KPO announced the establishment “Project 365," which includes the "green transformation" of the Karachaganak field. The company expects to develop a clear strategy to achieve carbon neutrality at the field, defining the intermediate stages to reduce greenhouse gas emissions. The first studies on CO_2 capture and storage were launched in 2021.[68]

4.7.3 Electric vehicles

Over the past several years, Kazakhstan's imports of electric vehicles have risen sharply, particularly from China (see Figure 4.17 Number of electric cars imported by Kazakhstan). The number of electric cars in Kazakhstan tripled from 491 in 2021 to

62 Our analysis for Russia-produced hydrogen shows that it is extremely costly for the product to reach global markets. In the case of Europe, for example, our research indicates that it is actually less expensive on a delivered basis to use Russian gas export infrastructure to deliver gas to Europe and reform it there into hydrogen than to transport hydrogen produced within Russia to Europe; see the IHS Markit Strategic Report *Russia's National Hydrogen strategy: Toward a new energy future?*

63 KMG's Low-Carbon Development Program (LCDP) 2022-2031, p. 33.

64 Air Liquide Munay Tech Gases LLP is a joint venture between Air Liquide (75%) and KMG (25%), established in 2016 for the production and supply of industrial gases needed by Kazakhstani oil refineries; pnhz.kz, 21 June 2017, https://www.pnhz.kz/press_center/news/?ELEMENT_ID=190.

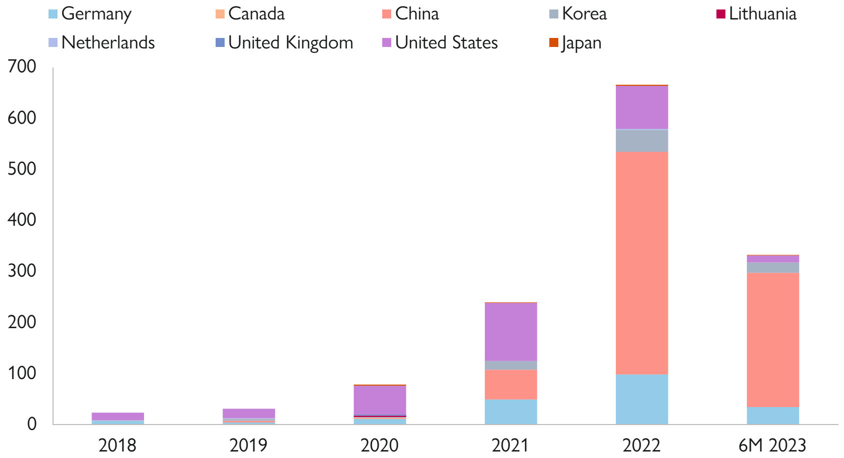
65 On 27 December 2017, a contract was signed for the sale of the existing hydrogen production unit at the Pavlodar refinery—with a total capacity of 31,000 Nm^3/h (normal cubic meters per hour)— to ALMTG.

66 KunTech is a Kazakhstan-based company involved in research and production of solar heating devices and solar collectors as well as a trader in the I-REC system; see https://kuntech.kz.

67 "CCUS pilot project to assess the potential for CO_2 injection to enhance oil recovery from depleted oil reservoirs," The Concept of Low-Carbon Development of Samruk-Kazyna JSC, dated 25 August 2020.

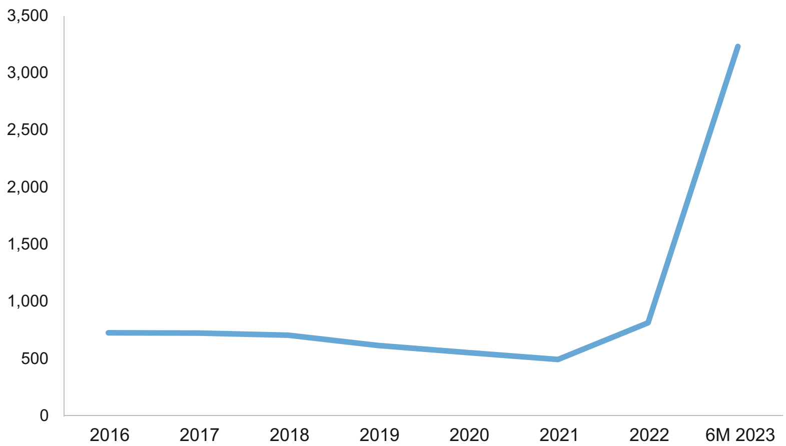
68 KPO Sustainability Report 2021.

Figure 4.17 Number of electric cars imported by Kazakhstan



Source: S&P Global Commodity Insights, Committee of State Revenues. © 2023 S&P Global.

Figure 4.18 Number of electric passenger cars in Kazakhstan



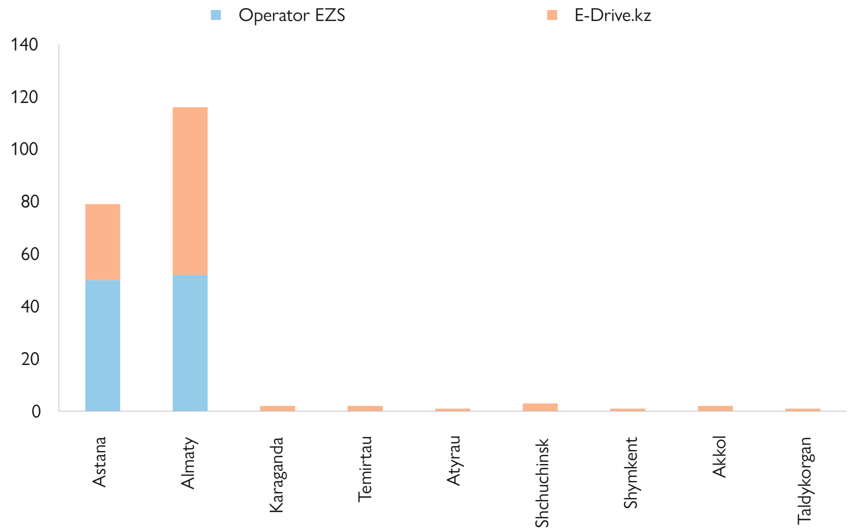
Source: S&P Global Commodity Insights, Bureau of National Statistics RK. © 2023 S&P Global.

3,229 in mid-2023 (see Figure 4.18 Number of electric passenger cars in Kazakhstan). As of 1 June 2023, there were a total of 3,590 electric vehicles in the country, including 3,229 passenger cars, 226 cargo vehicles, and 135 buses. There are only 203 electric car charging stations in the country, with the most located in Almaty (116 stations) and Astana (79 stations). Other major cities either may have no charging stations at all or 1-2 stations at best (see Figure 4.19 Number of charging stations for electric vehicles in Kazakhstan by city). There are two companies in Kazakhstan that specialize in the installation and operation of electric charging stations, EZS Operator LLP and eDrive.kz. Tariffs at eDrive.kz stations vary from 40 tenge to 70 tenge/kW at slow AC stations, and from 50 tenge to 80 tenge/kW at fast stations (depending on the capacity of the station). In Kazakhstan there is no legal framework regulating tariffs at charging stations for electric vehicles.

Kazakhstan is actively promoting domestic production of electric cars. Production of electric cars is currently planned to begin in 2035. The following projects have already been announced:

- A multi-brand plant with a full workshop for the production of Chinese cars. In September 2022, Astana Motors signed memorandums with automobile concerns Chery Automobile Company, Changan International Corporation, and Great Wall Motor to produce these Chinese brand cars (Chery, Changan, and Haval) in Almaty city. The start of construction is scheduled for 2025 with a production capacity of 90,000 vehicles per year, of which 60% is planned for export to neighboring CIS countries. The preliminary cost of the project is estimated at $200 million.
- During 2020-21, in cooperation with China-based company Yutong Hongkong Limited CN.China, assembly lines for Yutong buses and specialized equipment at the QazTehna LLP plant were installed in Karaganda Oblast. QazTehna LLP was established in 2019; the shareholders of the company are Genko International LLP (54%), Onay Pay LLP (25%), SPK Saryarka (20%), and Sinoyutong International PTE., Ltd (1%).[69] The main supplier of car kits for production is Yutong Hongkong Limited CN.China — a subsidiary of Zhengzhou

Figure 4.19 Number of charging stations for electric vehicles in Kazakhstan by city



Source: S&P Global Commodity Insights, Committee of State Revenues.

Yutong Group Co. Ltd. The cost of the project is about 22.1 billion tenge ($49.2 million) with capacity of 500 units of specialized equipment and 1,200 buses, both with an internal combustion engine and electric motor.

- In 2022, Hyundai Trans Auto, a subsidiary of Astana Motors, started assembly of Golden Dragon buses in Almaty city. In early 2019, Hyundai Trans Auto became an official distributor for the production and sale of Golden Dragon buses in Kazakhstan after signing an agreement with Chinese bus manufacturer Xiamen Golden Dragon Bus Co., Ltd.[70]
- Start-up Qoshcar Automotive announced plans to create an electric or hybrid car engine, and to produce 4,000 cars annually; it also intends to manufacture its own vehicle charging stations. Development and construction of the first prototype is estimated at $2 million. Although the Qoshcar Automotive project started in April 2022, as of March 2023 company was still searching for an investor.

4.7.3.1 Policy support

In 2022, the Mazhilis (Kazakhstan's lower parliament) initiated a draft law on the promotion of environmentally friendly transport and the development of infrastructure for electric cars. The bill provides for free parking spaces in paid parking lots, creation of designated places for charging electric vehicles, and the allocation of a special green registration numbers.[71]

According to the Committee of State Revenues of Kazakhstan, imports of electric vehicles from countries that are not members of the Eurasian Economic Union (EAEU) are exempt from paying duties and value added tax. This applies to import quotas of 10,000 EVs for 2022 and 15,000 for 2023 assigned by the Eurasian Economic Commission. Also, there are no recycling fees from 4 June 2021 for electric cars.[72]

4.7.4 Biofuels

The production and use of biofuels is not widespread in Kazakhstan. The only commercial-scale project is the BioOperations LLP plant that produces bioethanol from wheat waste.[73] The plant, with a capacity of 35,000 tons/year, is located in Taiynsha city, North Kazakhstan Oblast. The company exported bioethanol to Belgium in 2021, and began exporting bioethanol to the UK as well. BioOperations, previously known as BioKhim, began operations in 2006, but had gone bankrupt in 2012. Reconstituted as BioOperations, the company resumed production of bioethanol at the end of 2020 after a major modernization.

4.7.4.1 Policy support

Legislative efforts to drive further expansion of bioethanol in industry include a new law that was passed on 11 December 2022. The original definition and use of bioethanol was expanded to include its use in the chemical and related industries.[74]

69 Finance report of QazTehna LLP for 2021.

70 Golden Dragon buses have diesel, LPG, and electric engines.

71 On the introduction of amendments and additions to some legislative acts of the Republic of Kazakhstan on the promotion of environmentally friendly transport and the development of infrastructure for electric vehicles (Initiated by deputies); https://parlam.kz/ru/mazhilis/post-item/36/15944.

72 The recycling fee for electric vehicles was reset to zero in May 2021, which implies that there is no fee when importing into Kazakhstan or when producing electric vehicles, electric buses, or electric trucks.

73 Bioethanol is dehydrated ethyl alcohol produced from raw materials of biological origin, intended for blending with petroleum products or used for the production of fuel components, octane-enhancing additives, fuel additives, ethers, or use for the production of chemical and related products.

74 The Law of the Republic of Kazakhstan dated 15 November 2010 No. 351-IV.

Table 4.3 Projected impact of BAT implementation by industry

Industry	BAT reference book title	Emissions reduction (%)	Total reduction (t/y)
Oil and gas	Oil and gas refining and processing	13	75,000
	Oil and gas upstream production	56	
Chemical	Inorganic chemicals production	60	4,200
Cement	Cement and lime production	35	12,682
Mining and metallurgy	Lead production (mining, smelting, and processing)	70	109,320
	Copper and precious metals (including gold) production	65	
	Zinc and cadmium production	55	
	Non-ferrous metal ores (including precious metals) production and processing	75	
	Iron ore (including other ferrous ores) production and processing	80	
	Ferroalloys production	77	
Energy	Energy efficiency in economic and/or other activities	Reduction in fuel consumption - 40%	706,023
	Fuel combustion at large installations for energy production	78	
Total		**60**	**907,225**

Source: S&P Global Commodity Insights, IGTIC.

4.8 Update on Environmental Code Provisions for BAT in Industry

The 2021 Environmental Code introduced a number of important initiatives aimed at reducing and mitigating the environmental impact of economic activities, particularly the operations of large industrial enterprises. Currently efforts are underway to prepare domestic operators for a shift to Best Available Techniques (BAT) principles. The Code mandates that by 2025, the top 50 enterprises responsible for 80% of emissions must obtain Integrated Environmental Permits based on BAT principles. Failure to comply will result in an increase in environmental payments. The current lack of incentives for the shift from the state makes it challenging to encourage the modernization of production processes. The Environmental Code as well as the introduction of BAT principles and their implications were covered in detail in *The National Energy Report 2021.* This section provides an update.[75]

According to the Ministry of Ecology and Natural Resources, an integrated technological audit was conducted at 94 enterprises in key industries as part of the transition towards the BAT principles by the end of the August 2023. Additionally, 83 industry reports were generated. For the 50 largest emitters during 2021-23, 16 industry-specific BAT reference books were developed. There are plans to develop 14 more BAT reference books during 2024-27.[76]

Transitioning to BAT, especially in the power sector, faces various financial, technological, logistical, and organizational challenges that require a comprehensive approach. Particularly challenging is the fact that many power plants still operate using outdated technologies that have exceeded their life expectancy. The Minister of Energy, Almasadam Satkaliyev, reported that a technical audit of 57 stations revealed that 62% of power boilers and 58% of turbines have exceeded their lifespan and require immediate replacement. A total of 2.5 GW of capacity also needs to be replaced.[77] Therefore, among the first to be developed was the BAT handbook for "Fuel Combustion at Large Installations for Energy Production," which along with the BAT handbook for "Energy Efficiency in the Implementation of Economic and (or) Other Activities" has been preliminarily assessed by the International Green Technologies and Investment Projects Center (IGTIC) to significantly reduce pollutant emissions (see Table 4.3 Projected impact of BAT implementation by industry).

As Kazakhstan prepares to adopt BAT principles, experts have determined that many of the parameters set by the EU are currently unattainable by Kazakhstan. Therefore, transitional measures have been proposed to extend implementation times and soften some technological indicators. While emission standards in reference books often align with those in the EU, some concessions may still be necessary based on unique industry characteristics. For instance, the BAT handbook for "Fuel Combustion at Large Installations for Energy Production" proposes a more gradual move towards established standards starting with particulate matter emissions and only later addressing gaseous emissions.

A differentiated approach to setting the maximum permissible emissions for new and existing production facilities may be sensible, recognizing that production technologies tend to

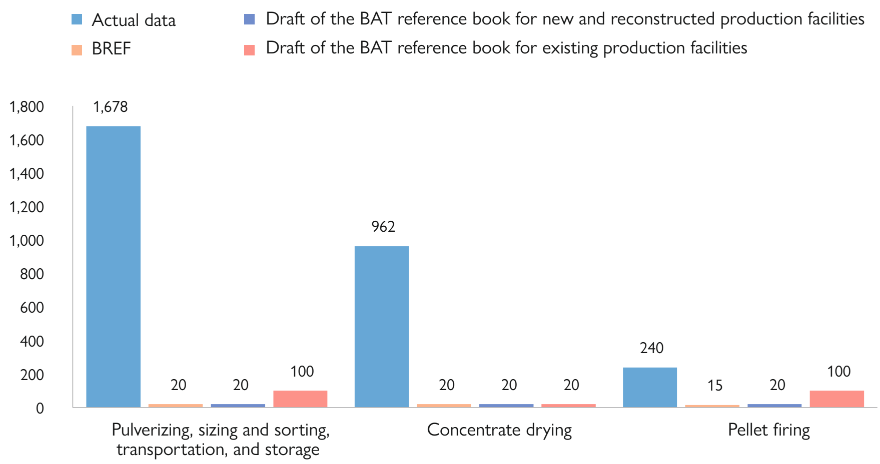
74 The Law of the Republic of Kazakhstan dated 15 November 2010 No. 351-IV.

75 See Section 2.6.1 and 2.6.2 in *The National Energy Report 2021*.

76 See the Ministry of Ecology and Natural Resources' report, outlining the activities for the year 2022; https://primeminister.kz/ru/news/reviews/v-minekologii-podveli-itogi-raboty-za-2022-god-1203351.

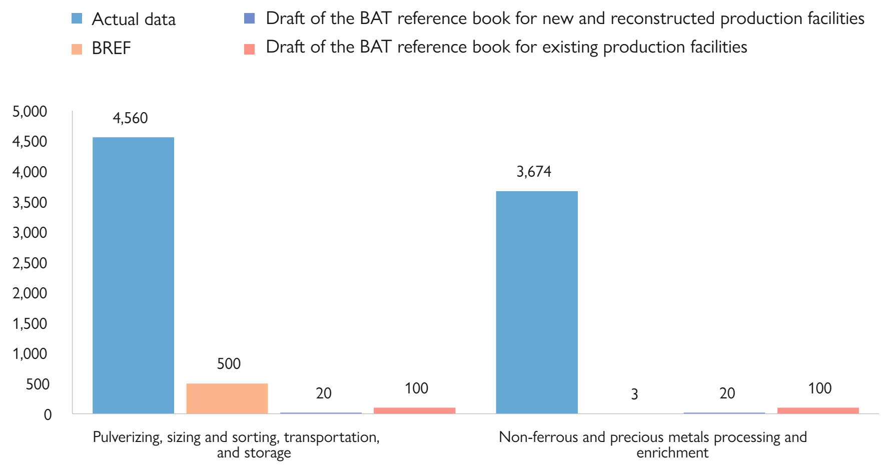
77 https://primeminister.kz/ru/news/povyshenie-tarifov-na-kommunalnye-uslugi-budet-poetapnym-alibek-kuantyrov-24742.

Figure 4.20 Particulate (dust) emissions from iron ore (including other ferrous ores) production and processing (mg/Nm³)



Source: S&P Global Commodity Insights, IGTIC.

Figure 4.21 Particulate (dust) emissions from non-ferrous metal ores (including precious metals) production and processing (mg/Nm³)



Source: S&P Global Commodity Insights, IGTIC.

become more advanced and environmentally-friendly over time (see Figure 4.20 Particulate (dust) emissions from iron ore (including other ferrous ores) production and processing and Figure 4.21 Particulate (dust) emissions from non-ferrous metal ores (including precious metals) production and processing). New production facilities can take advantage of modern equipment and processes that help reduce emissions of pollutants and improve the level of control over production processes. Moreover, the field of environmental protection is continually evolving, leading to regular updates and tightening of environmental standards, which are considered when updating BAT reference books every eight years. To minimize negative impacts on the environment and public health, *new production facilities must comply with stricter regulations.*

It is worth noting that implementing stricter regulations for new productions does not exempt existing enterprises from following enhanced measures to reduce their environmental impact. Renovating and modernizing current production facilities are equally crucial steps towards reducing pollution and complying with environmental requirements.

4.9 High-Level Takeaways

Government support for reducing carbon emissions is crucial for achieving climate targets and transitioning to more sustainable development. To achieve these goals, Kazakhstan must develop and implement various support measures that incentivize companies and investors to participate in decarbonizing the economy. Reliance only on "sticks" (regulations), without any clear path that investors see for returns, will drive away investment.

To effectively decarbonize its economy, a primary focus should be on decarbonizing the power sector. With nearly 70% of electricity generated from outdated coal-fired plants, a strategic shift away from coal reliance towards gas and non-fossil fuel sources will produce a significant carbon emissions reduction. However, the pace of the shift needs to be judicious and careful for energy security reasons. This undertaking would also create a foundation for sustainable energy transformation as the country's economy becomes more electrified. Kazakhstan's substantial support for renewable energy development is commendable and played a pivotal role in driving its rapid deployment.

Going forward it is also important for the government to extend its attention to other critical initiatives to mitigate carbon emissions (particularly the ETS) and maintain a balance between environmental and energy security priorities. Kazakhstan's ETS offers great potential to reduce the country's GHG emissions. As demonstrated through the experience of the EU, refining and finetuning the operations of ETS requires some time. In Kazakhstan, the current ETS system still needs operational improvements and a better mechanism for carbon pricing. To incentivize greener solutions the following adjustments to the ETS appear warranted:

- **Expanding the scope of sectors covered and including other types of emissions.** This would increase the overall effectiveness of the emissions trading system in Kazakhstan. Currently, Kazakhstan's ETS focuses solely on CO_2 emissions from relatively few sectors. To incorporate more emitters and drive a fairer distribution of responsibility for emissions across the economy, there are plans to expand the ETS to include other industries and GHGs.

- **Progressively reduce annual emission caps (allowances).** Prior to 2022, these had been increasing over time, but with the transition to the fifth phase of operation (2022–25), allowances are now decreasing owing to the implementation of a linear reduction factor of 1.5%. To ensure Kazakhstan meets its unconditional commitment to the Paris Climate Agreement, it may be necessary to further raise this reduction factor. This could be particularly important if the sectors that are currently outside the system (“unregulated”) remain that way in the future.

- **Introduce an auction for the distribution of initial allowances.** This is a useful method to increase transparency and efficiency in carbon reductions and allocations and greatly helps in establishing a price for carbon. As of yet, no auctions have been conducted on Kazakhstan's ETS. It is crucial to initiate the allocation of at least some portion of initial allowances through auctions. However, auctions should be introduced gradually, taking into account the economic realities of Kazakhstan's entities.

- **Other measures are needed to bolster the ETS.** Zhasyl Damu must take a number of decisive actions by implementing several additional measures. This could involve introduction of a robust market stability reserve, developing more efficient benchmarks, and the enhancement of the underlying monitoring, reporting and verification system to drive improved performance.

In adopting BAT principles, borrowing from EU practice, it is important to recognize that many of the parameters set by the EU for BAT are currently unattainable by Kazakhstan; therefore, localized transitional measures are needed that reflect this reality, such as extending implementation times and softening some technological indicators. Similarly, a differentiated approach to setting the maximum permissible emissions for new and existing production facilities may be sensible.

CHAPTER 5

KAZAKHSTAN'S OIL SECTOR

5. KAZAKHSTAN'S OIL SECTOR

5.1 Key Points

► The oil industry has recovered from the bulk of the negative impacts of the COVID-19 pandemic, but fallout from the sharp escalation of armed conflict in Ukraine from February 2022 has brought myriad new challenges. Still, most trends in Kazakhstan's oil balance still remain generally positive, with another year of robust domestic product demand. In our base-case outlook, oil production and exports both reach a maximum fairly soon—in the mid-2020s—and then slowly decline during the remainder of the outlook period to 2050. In contrast, refinery throughput remains on an upward slope, reflecting relatively strong continued domestic product demand growth. Specifically, our outlook during 2023-50 is for oil production to fall to 72.1 MMt (1.44 million b/d) and for net oil exports to contract by about 26% to 48.3 MMt (966,000 b/d), while refinery throughput rises by 24% to 22.3 MMt (446,000 b/d).

► Kazakhstan's oil production profile mainly reflects the trajectories of the "Big 3" fields—Tengiz, Kashagan, and Karachaganak—being developed by IOC-led consortia. Kazakhstan's official OPEC+ program currently envisages limits on national oil output through at least the end of 2024. These three fields contributed 63.1% of national oil output in 2022, and their share is expected to grow to a maximum of 71.0% in 2029 before contracting to about 60% of the total in 2050. In short, the mega projects' growth or decline rates and interruptions due to maintenance programs or other issues typically have more impact on the national production profile than the country's voluntary OPEC+ production quotas. The main driver of the national production trend in the early 2020s is the Tengiz Future Growth Project, which is scheduled to ramp up during 2024-25, while an expected second phase of Kashagan will subsequently partially offset ongoing decline at older fields.

► Full realization of Kazakhstan's oil production potential ultimately depends on attraction of investment in new upstream projects through further improvements to the regulatory and fiscal regime. Positive recent developments include adoption of Improved Model Contract (IMC) legislation offering tax and other incentives for complex projects, but the IMC suffers from some of the same limitations of the typical (existing) model contracts, including a lack of clarity and transparency concerning local content rules. One signpost of investor reluctance to undertake new upstream projects without further amelioration of above-ground conditions is the limited success in new upstream bidding rounds within the framework of the online (electronic) process for auctioning E&P blocks (e.g., cancellations, insufficient number of participants, and the lack of participation by IOCs). Current fiscal terms for mature fields in Kazakhstan also appear inadequate for full implementation of redevelopment plans by the national oil company KazMunayGaz (KMG) to significantly slow or reverse decline rates at legacy fields.

► Kazakhstan has intensified efforts to diversify its crude oil export routes since February 2022, with an initial focus on trans-Caspian outlets to bypass Russian territory—reflecting heightened concerns about Russian transit risk. This includes concerns over the reliability of the Caspian Pipeline Consortium (CPC) pipeline route, which handled 82.1% of Kazakh oil exports in 2022 (and more than 95% of Kazakh oil exports transited Russia). Kazakh authorities have tasked KMG to diversify export flows by boosting trans-Caspian volumes in particular, and this has meant the resumption of regular shipments via the Baku-Tbilisi-Ceyhan (BTC) pipeline. But infrastructure constraints and high transportation costs impede a very large-scale ramp-up of such volumes. In the S&P Global base case, Kazakhstan's trans-Caspian shipments longer term remain in a range of 5-10% of total Kazakh oil exports, in contrast to an aspirational government target equating to over a quarter of Kazakh export volumes.

► Downstream, Kazakh refinery output of all the primary products increased for the second year in a row in 2022. Diesel fuel is the single largest component (product) in Kazakhstan's refinery slate and in its domestic consumption balance, and diesel is expected to retain this leading role over the outlook period; altogether, diesel output surges by nearly 90% to 10.3 MMt by 2050, driven by a 126% jump in domestic diesel demand, mainly from trucking, to 12.3 MMt. After diesel, gasoline production is expected to register the strongest growth during 2023-50 on the back of increasing private car ownership (and relatively limited expansion of alternatives to gasoline-fired vehicles through 2050), while kerosene output also increases robustly in response to demand growth in the aviation segment. The base case is for an overall rise of Kazakhstan's domestic apparent consumption of all products by 43.0% to 22.8 MMt in 2050. However, our outlook for domestic product consumption is contingent on liberalization of domestic crude and refined product prices, whereby these prices reach export netback parity levels by around 2030. If prices are kept artificially low, in contrast, domestic product demand will be greater than in our current base case.

► Our outlook envisions significant expansion of the Shymkent refinery, located in southern Kazakhstan, where product consumption growth is highest. The S&P Global base case assumes that a 50% increase in Shymkent capacity is sufficient to meet the expected increase in domestic product demand, in conjunction with limited product imports, but through market competition consistent with EAEU integration rather than ad hoc administrative measures such as temporary product trade bans and other controls.

5.2 Overview of Oil Balance Dynamics and Industry Ownership Structure

This section summarizes key changes in Kazakhstan's oil balance during 2021-22 and our outlook for 2023-50 dynamics. It then provides an overview of the geographical distribution of major oil sector assets as well as the industry ownership structure.[1]

1 For additional background, see *The National Energy Report 2021*, Chapter 3.

Table 5.1 Crude oil/condensate balance for Kazakhstan (MMt)

	2015	2016	2017	2018	2019	2020	2021	2022	Percent change 2021-22
Production	79.5	78.0	86.2	90.4	90.6	85.7	85.9	84.2	-1.9
Total exports	64.8	63.4	69.6	70.2	70.0	70.6	65.7	65.2	-0.8
Exports outside FSU	61.6	61.6	69.2	69.4	69.8	70.0	65.6	65.0	-0.9
Exports to FSU	3.1	1.7	0.4	0.8	0.2	0.5	0.1	0.2	76.9
Russian Federation	2.8	0.8	0.1	0.5	0.1	0.1	0.1	0.0	-28.8
Ukraine	0.3	0.6	0.0	0.0	--	--	--	--	
Azerbaijan	--	0.1	0.1	0.1	--	--	--	0.1	
Kyrgyzstan		0.1	0.0	0.0	--	0.0	--	--	
Uzbekistan	0.0	0.1	0.2	0.2	0.1	0.5	0.1	0.1	37.2
Belarus	--	0.0	0.1	0.0	0.0	0.0	--	--	
Total imports	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0
From Russia*	7.0	7.0	10.1	10.0	10.0	10.0	10.0	9.9	-0.8
From Other	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0
Net exports	64.7	63.4	69.5	70.2	70.0	70.6	65.7	65.2	-0.8
Consumption (apparent)	14.7	14.7	16.7	20.2	20.6	15.1	20.2	19.0	-5.7
Refinery throughput	14.5	14.5	14.9	16.4	17.0	15.8	17.0	17.9	5.2
Pavlodar	4.8	4.6	4.7	5.3	5.3	5.0	5.4	5.5	1.4
Shymkent	4.5	4.5	4.7	4.7	5.4	4.8	5.2	6.2	20.2
Atyrau	4.9	4.8	4.7	5.3	5.4	5.0	5.5	5.2	-4.6
Other facilities	0.4	0.6	0.7	1.1	1.0	1.0	1.0	1.0	2.9
Other consumption**	0.3	0.2	1.8	3.8	3.6	-0.7	3.1	1.1	-64.6

Notes: *Officially considered transit to China or Uzbekistan since 2014.

**Balancing item; its composition includes throughput by other (mini)refineries, field and transportation losses (including losses in stabilization of condensate), changes in stocks, direct crude use, etc.

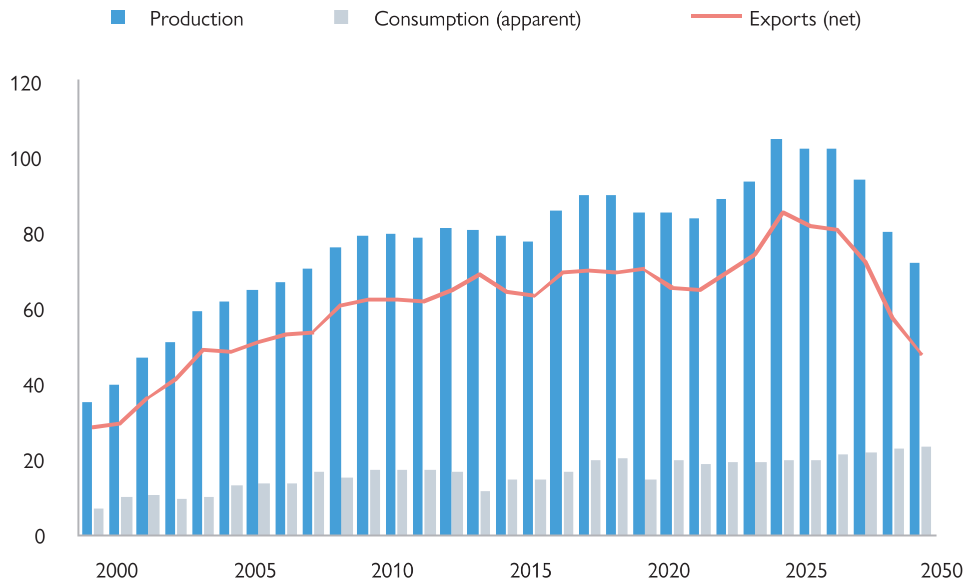
Source: S&P Global Commodity Insights, National trade statistics, Ministry of Energy RK.

The recovery of Kazakhstan's oil industry from the negative impacts of COVID-19 remains uneven, and in 2022 oil production, exports, and apparent domestic consumption still remained below the pre-pandemic level (see Table 5.1 Crude oil/condensate balance for Kazakhstan). In 2022, national oil production fell by 1.9% to 84.2 MMt (1.77 million b/d), oil exports declined by 0.8% to 65.2 MMt (1.30 million b/d), and apparent crude oil consumption contracted by 5.7% to 19.0 MMt (0.38 million b/d), even as refinery throughput rose by 5.2% to 17.9 MMt (0.36 million b/d).

Key 2023 signposts so far indicate that Kazakh oil production, exports, and domestic refined product demand will all increase on an annual basis this year—reversing the 2022 decline trend—while refinery throughput remains somewhat sluggish. The S&P Global base case is for Kazakh oil production to continue growing in both 2024 and 2025, after which a slow but steady decline sets in, leaving national liquids output roughly 14% lower in 2050 than in 2022. The bulk of oil output continues to be directed to export markets, but net export volumes contract (along with aggregate oil production) longer term, falling by 26% during the outlook period alongside a 25.0% increase in domestic apparent oil demand. As a result, the share of total production directed to export markets declines from 77.4% in 2022 to about 67% in 2050 (see Figure 5.1 Kazakhstan's crude oil/condensate balance: Outlook to 2050).

Roughly 95% of the country's oil/condensate reserves are located in western Kazakhstan in three petroleum basins: Precaspian, Mangyshlak, and North Ustyurt. Kazakhstan's main oil-producing area is in the northwestern portion of the country: the two largest producing fields, Tengiz and Kashagan, are both located in Atyrau Oblast (province) (although Kashagan is about 80 km offshore in the Caspian Sea), while the third largest field, Karachaganak, is in West Kazakhstan Oblast near the Russian border. These “Big 3” fields accounted between them for 63.1% of national output in 2022.

Figure 5.1 Kazakhstan's crude oil/condensate balance: Outlook to 2050 (MMt)



Source: S&P Global Commodity Insights.

Smaller fields in western Kazakhstan and elsewhere export some of their output but also supply the country's refineries with crude feedstock. Kazakhstan contains three large oil refineries and 19 mini refineries spread across the country. The three major plants—Atyrau, Pavlodar, and Shymkent—accounted for 94.4% of national refinery throughput in 2022, and are located, respectively, in the northwest (Atyrau Oblast), northeast (Pavlodar Oblast), and south (South Kazakhstan Oblast). (See Figure 5.2 Kazakhstan's oil sector (selected key elements).)

The corporate structure of the Kazakh oil industry varies widely by segment; i.e., upstream, midstream, or downstream. The upstream oil production profile and export stream is dominated by the IOC-led consortia developing Tengiz (Tengizchevroil [TCO][2]), Kashagan (North Caspian Operating Company [NCOC][3]), and Karachaganak (Karachaganak Petroleum Operating Company BV [KPO][4]), while the national oil company, KazMunayGaz (KMG), is the single largest oil industry player at the individual company level in Kazakhstan, owning most key assets across the oil industry value chain. KMG has significant minority stakes in each of the "Big 3" projects, but most of KMG's equity oil output comes from fully-owned subsidiaries producing mainly from mature onshore fields. KMG's KazTransOil (KTO) subsidiary handles much of Kazakhstan's crude oil transportation. KMG also controls the Pavlodar and Atyrau refineries, and has a 49.72% stake in the Shymkent plant, whose majority owner is the China National Petroleum Corporation (CNPC). In 2022, KMG accounted for an estimated 26% of national oil production, 53% of oil transportation in Kazakhstan (including both trunk pipelines and sea transportation), and 84% of oil refining in the country (see Table 5.2 KMG oil industry assets and 2022 operating results).[5]

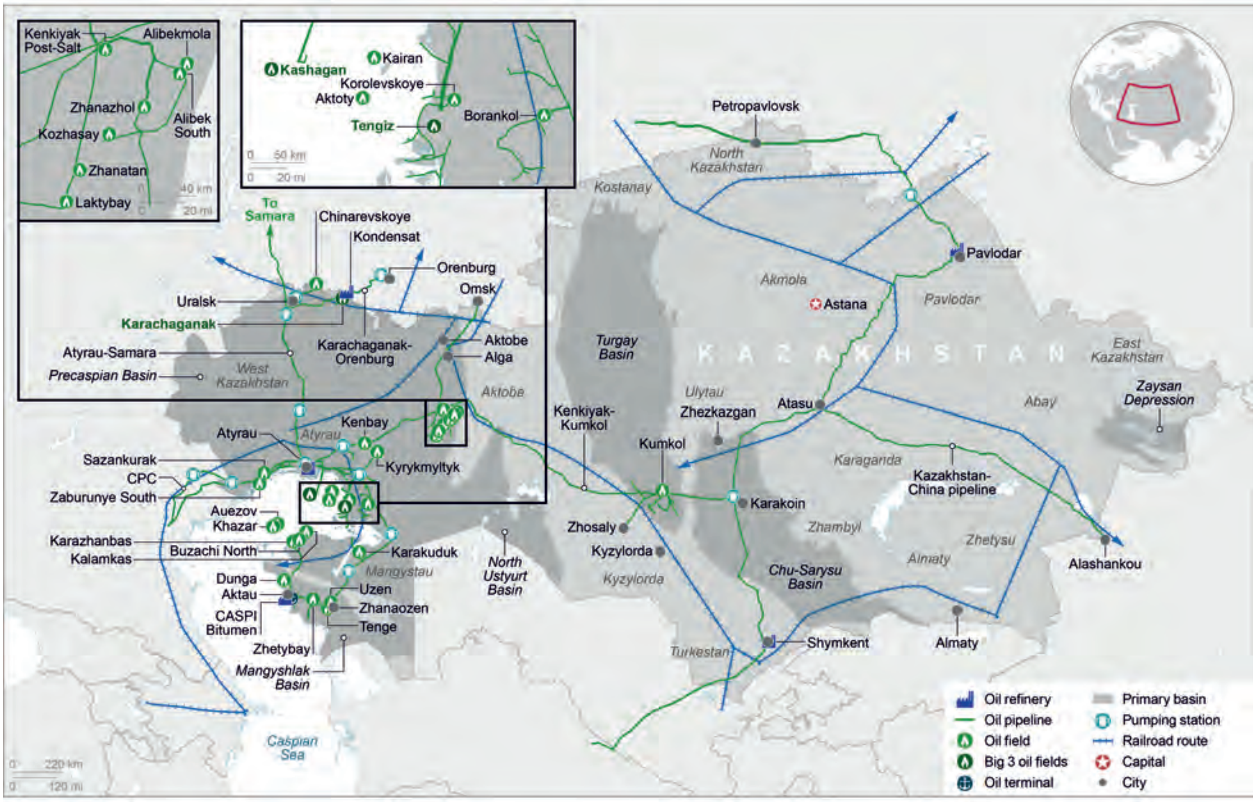
2 The TCO partners are Chevron (50%), ExxonMobil Kazakhstan (25%), KMG (20%) and Lukoil (5%).

3 NCOC is comprised of KMG (16.88%), Shell, TotalEnergies, Eni and ExxonMobil (each with 16.81%), CNPC (8.33%) and Inpex (7.56%).

4 The KPO shareholders are Shell and Eni (each with 29.25%), Chevron (18%), Lukoil (13.5%) and KMG (10%).

5 KMG Annual Report 2022, p. 38, https://www.kmg.kz/en/investors/reporting/.

Figure 5.2 Kazakhstan's oil sector (selected key elements)



Source: S&P Global Commodity Insights upstream E&P/basins/midstream content (EDIN): 2009695.

Table 5.2 KMG oil industry assets and 2022 operating results (key examples)

Upstream			Midstream			Downstream		
Producer	**KMG stake, %**	**2022 production, MMt (KMG share)**	**Asset**	**KMG stake, %**	**2022 transportation, MMt (KMG share)**	**Refinery**	**KMG stake, %**	**2022 throughput, MMt (KMG share)**
Operating assets			Pipeline			Major plants		
OzenMunayGaz	100	5.1	KTO	90	40.7	Atyrau	100	5.2
Embamunaigas	100	2.6	KCP	50	9.6	Pavlodar	100	5.5
Mangistaumunaigaz	50	3.0	MunayTas	51	2.9	PKOP	50	3.1
Kazgermunai	50	0.7	CPC	21	12.2	Mini-refineries		
Karazhanbasmunai	50	1.1	Marine fleet			Caspi Bitum	50	0.5
PetroKazakhstan	33	0.6	Kazmortransflot	100				
Kazakhoil Aktobe	50	0.3	Caspian Sea		0.6			
Kazakhturkmunay	100	0.4						
Urikhtau Operating	100	0.04						
Mega projects								
Tengizchevroil	20	5.8						
KMG Kashagan	17	1.4						
KMG Karachaganak	10	1.0						

Notes: KTO = KazTransOil, KCP = Kazakhstan-China Pipeline, CPC = Caspian Pipeline Consortium, PKOP = PetroKazakhstan Oil Products (Shymkent refinery).

Consolidated volume of oil transportation; i.e., including volumes of each individual pipeline company. Part of the oil volumes can be transported by two or three pipeline companies, and these volumes are accordingly counted more than once.

Other key KMG assets operating outside Kazakhstan include a 100% stake in the Batumi oil terminal in Georgia, controlling stakes in the Petromidia and Vega refineries in Romania, and Kazmortransflot's Black Sea fleet.

Source: S&P Global Commodity Insights, KMG.

5.3 Upstream

5.3.1 Reserves and exploration dynamics

Kazakhstan has a large oil resource base, which includes several major identified fields and the prospect of substantial oil reserves yet to be discovered, particularly in the country's offshore sector of the Caspian Sea. As of 1 January 2023, Kazakhstan's officially reported recoverable A+B+C1 oil reserves—considered roughly equivalent to the proven and probable reserve category in international nomenclature—amounted to around 3.25 billion tons (see Table 5.3 Kazakhstan's oil reserves in the A, B, C1, and C2 categories as of January 1, 2023).[6] This represents a 0.9% decrease compared with the A+B+C1 reserve volume as reported at the beginning of 2022.

S&P Global estimates Kazakhstan's remaining proven and probable reserves at around 3.48 billion tons (26.72 Bb) of crude oil and condensate at the end 2022.[7] This volume is not substantially changed from our estimate given for 2020 in *The National Energy Report 2021;* no large discoveries were subsequently made (the last major discovery was Kashagan in 2000) but revisions and small discoveries were sufficient for general replacement of production). One sign of the times, in Kazakhstan in any event, is the downturn in company spending on exploration in recent years. Investment in geological exploration work by subsoil users in Kazakhstan during 2020-22 fell by 25% compared with the period 2017-19, amounting to around 314.4 billion tenge ($0.7 billion) in total during the latest three-year period. In 2023, only about $190 million (84.7 billion tenge) is expected to be spent by KMG for geological exploration of oil and gas fields. One of this year's projects includes drilling a 5.5 km deep exploration well in the Paleozoic sediments in Kyzylorda Oblast.

An exploration milestone during 2021-22 was nevertheless execution of Stage 1 of the “Eurasia” project to study deep horizons of the Precaspian Basin. Stage 1 consisted of a $6 million state-funded report prepared according to international standards and involving collection and reinterpretation of geophysical and geological materials by a consortium led by Kazakhstan's SPC GEOKEN LLP research foundation. Completion of Stage 1 (launched in March 2021 and finished in November 2022) conceptually lays the groundwork for more capital-intensive project work: a second stage including regional seismic surveying at an estimated cost of $150 million over 2.5 years, and a third stage involving the drilling of a 15 km well and costing an estimated $350 million over 3 years. Funding of the next stages is supposed to come from industry, but specific sources remain to be identified, with the result that the schedule for additional project activity is also uncertain.[8]

5.3.2 Recent production trends and outlook

Kazakhstan produced 85.7 MMt (1.80 million b/d) of oil in 2020, 85.9 MMt (1.81 million b/d) in 2021, and 84.2 MMt (1.77 million b/d) in 2022. National production returns to a growth trajectory in 2023 on an annual basis in our base case, notwithstanding a number of new constraints this year. These include Kazakhstan's commitment in April 2023 to an additional crude oil output reduction within the framework of the OPEC+ alliance, and electric power outages in summer 2023 in particular that negatively impacted operations at various fields.[9] National oil output is expected to reach a maximum of 105.4 MMt (2.23 million b/d) already in 2025, followed by a subsequent slow decline to 72.1 MMt (1.51 million b/d) in 2050. In our alternative high case, national output reaches a maximum of 118.9 MMt (2.51 million b/d) in 2035, and subsequently declines to 92.7 MMt (1.94 million b/d) in 2050, while in the low case the maximum is only 94.2 MMt (1.99 million b/d) in 2025 and production falls to 44.3 MMt (924,000 b/d) in 2050 (see Figure 5.3 Outlook for Kazakhstan's oil production by case). Key assumptions underlying the high case include relatively aggressive development of upstream acreage by smaller producers whose aggregate existing reserve base and production potential is sizable and may be augmented by “new” production from additional producers and additional discoveries. The main difference between the low case and the base case is the absence of a Kashagan Phase 2 expansion program.[10]

The three mega projects remain the primary drivers of the national production profile, especially in the near to medium term. In the base case, the “Big 3” share of Kazakh oil production rises from 63.1% in 2022 to a maximum of 71.0% in 2029—due mainly to TCO and NCOC expansion, and partial stabilization of KPO output (see Figure 5.4 Outlook for Kazakhstan's oil production by major project/region to 2050 in the base case). After 2030, the “Big 3” share is expected to gradually decline, to around 60% by 2050. A host of smaller projects contribute as well to Kazakhstan's oil development, albeit less prominently, and we also assume a relatively slow decline in Kazakhstan's older, legacy fields (especially in western Kazakhstan), reflecting the growing application of new technology and improved production practices, which have the potential to significantly boost recovery coefficients at Kazakh fields generally. Industrywide, the recovery coefficient at fields in Kazakhstan averaged only 0.152 at last report, whereas a coefficient of around 0.357 could be attainable, according to a Kazakh government estimate based on an analysis of international practice.[11]

6 All ton data in this chapter refer to metric tons.

7 S&P Global Commodity Insights, Upstream Intelligence / Annual Review, *CIS Kazakhstan Annual Review 2022,* February 2023. The Energy Institute Statistical Review of World Energy reports Kazakhstan’s proved reserves at 3.9 billion tons (30.0 Bb) at the end of 2020, the latest year for which it provides data, https://www.energyinst.org/statistical-review/resources-and-data-downloads.

8 Potential project participants include KMG, Eni, Rosneft, CNPC, SOCAR, and NEOS Geosolutions, under terms of a memorandum of understanding signed between these companies and the Kazakh government in June 2017.

9 Power outages frequently complicated the upstream operations of KMG this year prior to July 2023 too. The company's primary producing subsidiary, OzenMunayGaz reportedly suffered 11 outages leading to the shut-in of 13,000 wells in the six months prior to the July electricity disruption. See S&P Global Commodity Insights, Platts European Power Daily, *Kazakhstan focused on infrastructure weakness after oil, power outages,* July 2023.

10 For background on Kazakh oil production trends, see S&P Global Commodity Insights, Market Briefing, *Eurasian Oil Export Outlook,* April 2023.

11 https://adilet.zan.kz/rus/docs/P1400000724 , “Ob utverzhdenii Kontseptsii razvitiya toplivno-energeticheskogo kompleksa Respubliki Kazakhstan na 2023-2029 gody”.

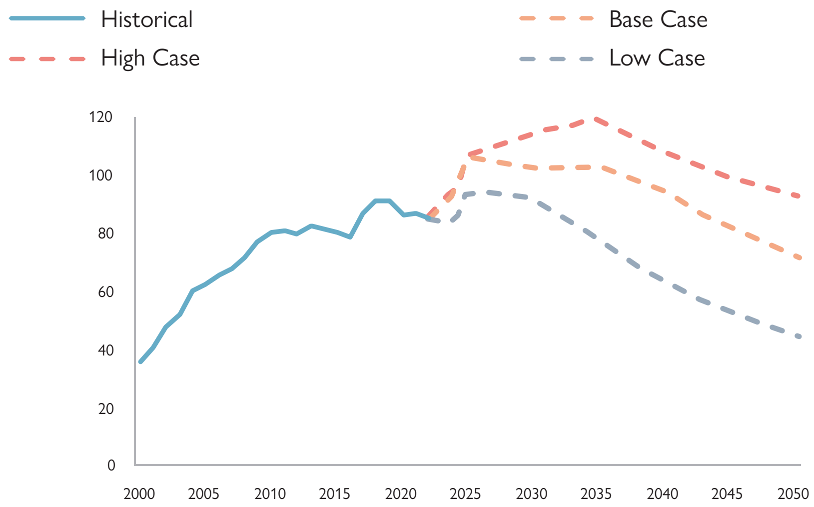
Table 5.3 Kazakhstan's oil reserves in the A, B, C1, and C2 categories as of January 1, 2023 (MMt)

	A+B+C1	C2	A+B+C1+C2
Crude oil	2,943	1,458	4,401
Condensate	312	88	400
Total	3,255	1,546	4,801

Source: Subsoil user data.

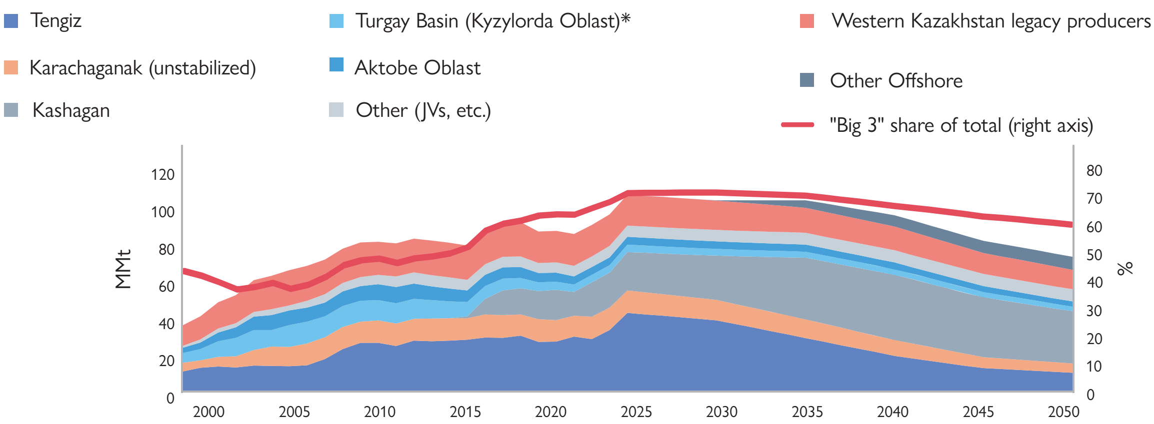
We also believe that the pledge by Kazakhstan, coordinated with other members of OPEC+, to limit crude oil output in the remainder of 2023 and 2024 will not really act as much of a brake, and Kazakhstan will likely produce somewhere close to its maximum available capacity—assuming no disruptions in Kazakhstan's oil exports transiting Russia. So far in 2023, Kazakhstan's monthly crude oil production volume has typically slightly surpassed the country's voluntary OPEC+ quota (see Figure 5.5 Kazakh oil (crude + condensate) output breakdown by month, and crude production as percent of OPEC+ quota).

Figure 5.3 Outlook for Kazakhstan's oil production by case (MMt)



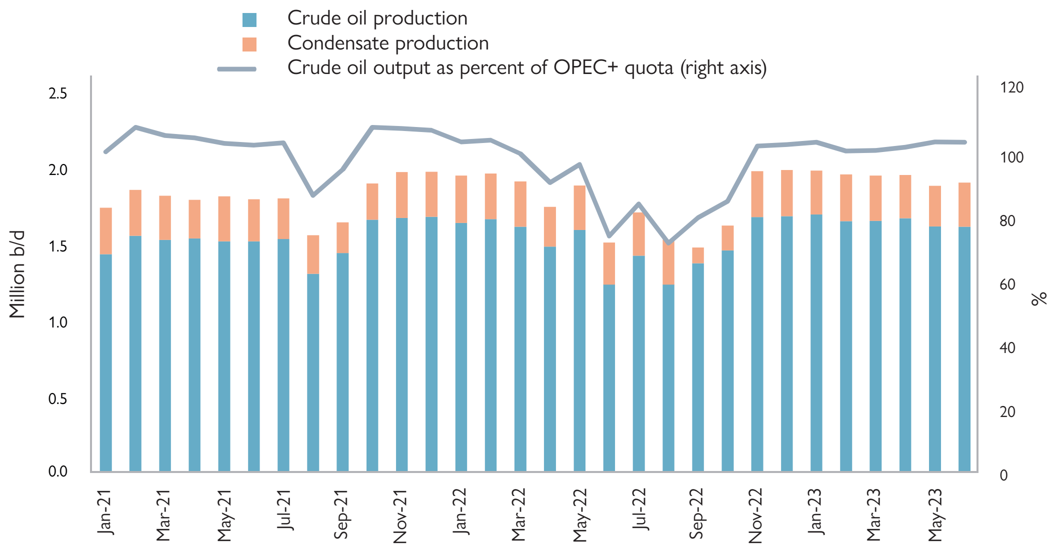
Source: S&P Global Commodity Insights (Eurasian Oil Export Outlook).

Figure 5.4 Outlook for Kazakhstan's oil production by major project/region to 2050 in the base case



Notes: *Includes Amangeldy in Zhambyl Oblast.
Source: S&P Global Commodity Insights (Eurasian Oil Export Outlook).

Figure 5.5 Kazakh oil (crude + condensate) output breakdown by month, and crude production as percent of OPEC+ quota



Source: S&P Global Commodity Insights, Bureau of National Statistics RK.

The following sections summarize key recent dynamics for the main Kazakh oil production streams and our outlook for their evolution.

Tengiz consortium (TCO)

The Tengiz project remains the largest Kazakh oil development by production, accounting for 34.6% of national oil output in 2022. Maximum annual Tengiz production to date was registered in 2019, when output reached 29.8 MMt (649,000 b/d). In 2020, output fell to 26.5 MMt (576,000 b/d), reflecting the impact of COVID-19 on global demand. Production partially recovered in 2021, and rose more significantly in 2022, to 29.2 MMt (636,000 b/d). In our base case, TCO production dips slightly in 2023, but then rebounds. The next phase of expansion, over 2024-25, is the Future Growth Project (FGP), with an estimated cost of $46.7 billion. The FGP is slated to add 12 MMt/y (260,000 b/d) to the field's overall production capacity. The consortium partners took a final investment decision (FID) for this project in mid-2016. First oil from the FGP is still expected in the second half of 2024. Following a quick ramp-up in production from the new capacity, to a new maximum output level of 42.0 MMt (915,000 b/d) in 2025, Tengiz then enters a decline trajectory that leaves field production at 9.9 MMt (216,000 b/d) in 2050 in the base case. Currently, we expect that in the post-plateau period, production at Tengiz will experience a sizable secular decline, barring the implementation of another investment round by the JV to attenuate the decline. A critical factor will be the government's decisions about the project in 2033 when the current JV expires.

Kashagan consortium (NCOC)

In 2022, Kashagan output declined by 21.9% to 12.7 MMt (269,000 b/d) after an August gas leak necessitated emergency repairs that negatively impacted production. Kashagan's recovery and growth this year is expected to be a primary driver of the expansion of Kazakh oil production overall in 2023. Field output reaches 18.4 MMt (391,000 b/d) this year in the S&P Global base case. The consortium's current Phase 2 expansion program includes two separate projects now in the planning stages: Phase 2A aims to increase oil production to 500,000 b/d, and Phase 2B would raise output to a higher ceiling, eventually planned at about 700,000 b/d.[12] Kashagan's future production trajectory varies widely in our scenarios depending on how Phase 2 is implemented. This two-pronged expansion goes forward more or less as planned in our base-case outlook, raising the field's output to a maximum of 35.0 MMt/y (743,000 b/d) in 2040, while 2050 output is expected at 28.0 MMt (595,000 b/d). In the high case, the buildup is somewhat more rapid and brings production up to a maximum of 36.5 MMt (775,000 b/d) in 2040. In the low case, however, the second phase expansion is never sanctioned, so production stretches to only about 22–23 MMt (470,000–480,000 b/d) through some additional minor debottlenecking, and in 2050 amounts to only 19.5 MMt (414,000 b/d).

Karachaganak consortium (KPO)

Karachaganak's annual gross production of liquids has been basically flat since 2007, ranging between about 11.3 MMt and 12.2 MMt (257,000–278,000 b/d); gross output in 2019 was 11.3 MMt (257,000 b/d), increasing to 12.2 MMt (277,000 b/d) in 2020, but amounting to 11.5 MMt (262,000 b/d) in 2021 and 11.3 MMt (257,000 b/d) in 2022. Karachaganak's liquids output is mainly condensate, so its operation has been exempt from OPEC+ restrictions. Field production loses approximately 18–19% of its volume in the process of stabilization (now undertaken entirely at the field itself; previously some took place within Russia), and this significantly reduces the liquids volumes available for pipeline shipment or exports. Karachaganak's fourth stabilization train

12 S&P Gobal Commodity Insights, Platts Commodity News, *Kazakhstan Kashagan expansion progressing 'well,' amid legal battle*, 16 June 2023.

(part of the project's second expansion phase), installed in 2010, increased the project's direct export capacity to 10.3 MMt (234,000 b/d) of stabilized liquids. To help maintain production, a gas debottlenecking project was launched in 2018 and was completed in March 2021. In December 2020, a general and amicable settlement between KPO and the government ended a long-standing dispute surrounding the profit oil formula in the 1997 production-sharing agreement. This settlement in turn set the stage for initiation of a larger project, aimed at maintaining liquids production at 10–11 MMt/y (215,000-237,000 b/d) in the longer term, through more gas reinjection, known as PRK-1A (or KEP-1A), and this project is expected to be completed in 2025.[13] Gross Karachaganak production nevertheless enters a long-term decline trajectory at around this same time in our base case, and gradually falls to 5.0 MMt (114,000 b/d) in 2050.

Other existing production streams

- ***Western Kazakhstan legacy producers.*** Production in this category (not to be confused with Kazakhstan's oblast of the same name) covers the output of five legacy Soviet-era oil producers, including the fully-owned KMG production subsidiaries, OzenMunayGaz and EmbaMunayGaz. Output by this mature group of producers will continue the general (albeit slow) decline that began in 2006–07 over the remainder of the outlook period; an above-average reduction in output in 2020–21 was followed by a slight uptick in 2022, to 17.0 MMt (324,000 b/d), but aggregate production for this group returns to a decline trajectory in 2023 in the base case, and falls to 10.5 MMt (200,000 b/d) in 2050. The decline rate in this category may nevertheless be further attenuated through timely implementation of various measures currently under way or in the planning stages. The KMG program to slow or reverse mature field decline rates involves a combination of hydraulic fracturing, horizontal drilling, steam injection and polymer injection. KMG is also exploring the potential to enhance oil recovery at depleted oil reservoirs by means of CO_2 injection within the framework of a carbon capture, utilization and storage (CCUS) project, as part of the company's 2022-2031 Low Carbon Development Program.[14]
- ***Aktobe Oblast.*** This region's production has generally been declining since 2013, and in 2022 amounted to 4.5 MMt (95,000 b/d); output is expected to fall further from current levels, to 2.8 MMt (59,000 b/d) in 2050.
- ***Turgay Basin (Kyzylorda Oblast).*** Regional production has been slowly falling since 2007, to the level of 4.0 MMt (84,000 b/d) in 2022; the outlook is for further decline, to 2.4 MMt (51,000 b/d) in 2050.
- ***Other (JVs, etc.).*** Crude oil produced by this category includes all onshore oil production from all other producers. This category comprises projects run mainly by small JVs and other international independents. In 2022, there were more than 50 producing entities within this category. Located predominantly in western Kazakhstan (mainly in Atyrau and Mangystau oblasts, although there is one in West Kazakhstan Oblast and one in East Kazakhstan Oblast), these projects' output has been about 5.3–6.0 MMt (102,000–115,000 b/d) in recent years. Although output for the category contracted overall in 2019–20, it partially recovered in 2021-22, reaching 5.6 MMt (108,000 b/d) in 2022. These producers' output is expected to expand some over the longer term, to a maximum of 6.6 MMt (127,000 b/d) in 2045 in the base case, and amount to 6.5 MMt (125,000 b/d) in 2050.

Offshore development post-Kashagan

Some offshore production streams aside from the Kashagan field are likely to emerge during the outlook period, facilitated in part by positive developments on the regulatory front in recent years; e.g., the government's 2021 decision to waive export duties on crude produced by new offshore projects and the 2023 adoption of the Improved Model Contract (IMC) regulatory and tax framework for complex upstream projects. But such policy improvements fail to ameliorate a number of key fiscal and other above-ground risks; these continue to challenge the attractiveness of developing additional shelf acreage for outside investors.[15]

Production from these other offshore fields will be driven by a combination of geology and investment conditions, and the range of what is possible is quite broad. Our outlook assumes some exploration success, although no new discoveries on the scale of Kashagan are made. The base case envisages output from this category starting in 2030, and key sources of production include the reconfigured Kalamkas-More/Khazar project, now moving forward into implementation within the framework of a joint venture between KMG and Lukoil on IMC terms. Overall, however, exploration and production in the Kazakh offshore post-Kashagan is expected to move rather slowly. One signpost is that a first exploration well drilled by another KMG-Lukoil JV in 2023 at the Zhenis block, within the framework of another JV, was unsuccessful; the partners subsequently announced that they were closing the project and returning the license block to the state. The net result is that aggregate growth of offshore production from sources other than Kashagan is limited to only 7.0 MMt (149,000 b/d) in 2050 in the base case.

5.3.3 Development of laws and regulations governing upstream operations

Kazakhstan has taken important steps recently to rationalize fiscal and subsoil policies that impinge on upstream investment. For example:

- in 2016 an ad hoc and non-transparent export tax system was replaced with an explicit oil export customs duty formula based on a sliding scale linked to world oil prices;
- in 2018, the Subsoil Code was introduced, replacing the Law on Subsoil and improving subsoil auction procedures; Tax Code amendments approved around the same time provided

13 S&P Global Commodity Insights, Insight, *Karachaganak partners and Kazakhstan finally resolve their long-standing dispute,* December 2020.

14 KMG has begun screening fields among the company portfolio to select a reservoir for CO_2 injection, and early indications are that the acreage of its OzenMunayGaz subsidiary is most suitable for this purpose. The company is also seeking to learn from the CCUS experience of Chevron, with whom KMG signed a memorandum of understanding in June 2022 to jointly explore low-carbon opportunities in Kazakhstan.

15 The above-ground risks were underscored once again in April 2023 by Kazakhstan's decision to launch multi-billion dollar arbitration proceedings against the NCOC consortium, along with the KPO consortium, alleging that the state's share of revenue should be higher under terms of the production-sharing agreements governing the projects. See S&P Global Commodity Insights, Energy Technical Report, *Kazakhstan Sues Operators of Karachaganak and Kashagan,* April 2023.

new fiscal incentives for selected upstream investments, including introduction of an Alternative Subsoil Use Tax (ASUT) for specified technologically complex projects;

- in 2022, a Subsoil Code amendment introduced the concept of "unconventional hydrocarbons" (including "shale oil"), facilitating the booking and development of reserves within these categories;
- in early 2023, IMC legislation was enacted offering additional fiscal relief for complex projects among other new incentives;
- and over the course of 2020-23 Kazakhstan launched and developed an ongoing electronic (online) auctioning procedure for E&P blocks.[16]

5.3.3.1 Improved Model Contract (IMC)

At the beginning of 2023, amendments and additions were completed to the relevant legislative acts in Kazakhstan, providing for the introduction of the IMC—a new subsoil contract option. The IMC aims to increase competitiveness and create conditions for attracting additional investments in the exploration of complex upstream projects; it is applicable to offshore and gas projects as well as to complex onshore projects. The IMC provides some incentives (or "preferences") that reflect a recognition by the Kazakh authorities of the special challenges involved in the development of its complex hydrocarbon deposits. Eligibility for the IMC is defined by technical characteristics of the field or geographic location (offshore, subsalt, under-explored basins, etc.). Substantive IMC incentives feature stability guarantees for selected fiscal and regulatory preferences, including reduced ASUT rates for complex offshore fields (see Figure 5.6 ASUT tax rates for complex offshore projects versus other projects), special amortization options for expenses incurred prior to the start of production, an option for international arbitration, and relaxed requirements for supplying crude oil to the domestic market.[17]

However, S&P Global's analysis indicates that the IMC terms probably do not go far enough to stimulate new upstream investment on the scale sought by Kazakhstan, especially in the current inflationary and geopolitical environment, and the current IMC regime actually retains several problematic aspects of the typical (existing) model contract (Subsoil Use Contract) that applies to less complex fields; e.g., both sorts of contracts include language that lacks clarity and transparency—for example, regarding local content rules. On balance, S&P Global concludes that the IMC fails to fully ameliorate a number of impediments that continue to challenge the attractiveness of developing these resources to outside investors: general taxes, environmental, and general regulatory terms that are not "locked" and stable throughout the project lifetime; onerous local content requirements for labor, equipment, and services (somewhat counterintuitive given the fact that development of many complex deposits would demand the highest level of international expertise); persistent administrative rigidities (e.g., annual work program reporting requirements); continued requirements for unrelated social and economic investments by companies in the regions in which their operations are located; and the requirement of a signing bonus.

5.3.3.2 Online auctions

Starting in 2020, Kazakhstan has been holding online auctions of E&P acreage, following Subsoil Code amendments to allow for this form of licensing, involving blocks across key petroleum basins in the country. A total of six such online auctions have now been held—one in 2020, two in 2021, two in 2022, and one so far in 2023 (a second 2023 auction is scheduled to take place on October 20). As noted in *The National Energy Report 2021*, the results of the initial auctions in 2020-21 fell short of expectations, as key international majors did not participate. The IOCs did not bid either in the 2022 online auctions or the first 2023 auction held in July, though one leading foreign NOC, Sinopec, bid in the December 2022 auction (and won an exploration block in the Precaspian Basin; Mangystau Oblast). The chief precondition for increased participation in online auctions—by foreign investors in particular—seemingly remains more systematic reform of Kazakhstan's upstream regulatory regime, including removal of the same sort of impediments that tend to limit investment within the IMC framework as noted above.

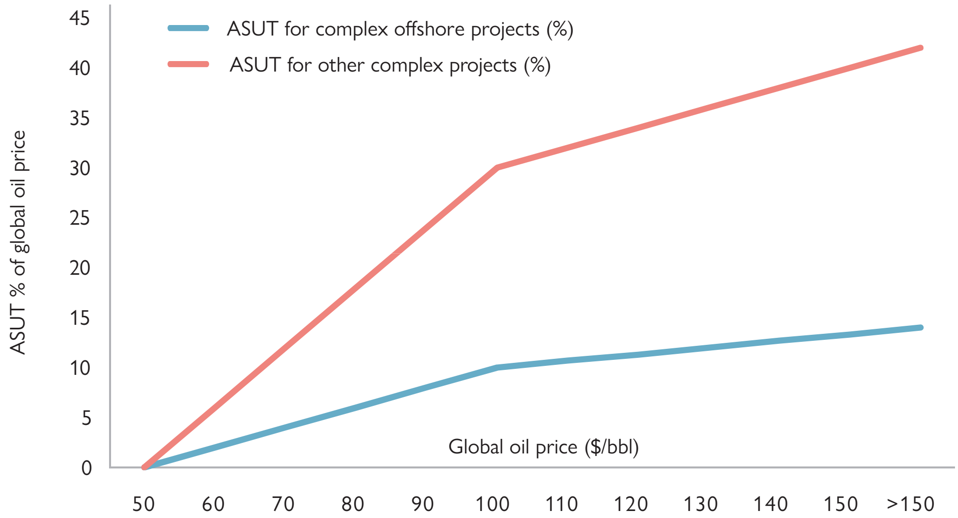
Key overall results of the online auctions held to date include the following (see Table 5.4 Comparison of the Kazakh Energy Ministry's online auctions for E&P blocks, 2020-23 (key indicators) and Table 5.5 Results of the Kazakh Energy Ministry's July 12, 2023 online auction for E&P blocks):

- ***Nearly 70 fields/blocks have been auctioned off so far on the online format, but the number of cancelations of planned bidding rounds has been even greater, largely due to an insufficient number of participants.*** For example, out of an initial 56 hydrocarbon plays for which the Energy Ministry invited bids in advance of the July 2023 auction, only 9 were ultimately bid on by investors.
- ***Over 60% of the blocks/fields that have been awarded are located in the Precaspian Basin.*** The number of Precaspian Basin awards to date totals 43; the next-largest number of block/field awards so far have been in the Mangyshlak Basin (7), Turgay Basin (4), and North Ustyurt Basin (4).
- ***The average territory of license blocks/fields that have been auctioned is about 1,100 square km.*** The largest award by territory so far has been the Sagiz block in December 2020, encompassing nearly 5,000 square km in the Precaspian Basin (stretching across parts of both Atyrau and Aktobe oblasts), while the smallest to date is the Alashkazgan field in November 2021, covering only 0.31 square km in the Precaspian Basin (in Aktobe Oblast).
- ***The total value of awards resulting from the auctions amounts to $304 million (where contract values have been reported), while the average contract value is $5 million.*** The highest-value contract reported so far was for the Zaburunye block in the Precaspian Basin (Atyrau Oblast), at around $67 million, won by Sarayshyk Petroleum LLP in November 2021.

16 For additional analysis of the 2017-21 subsoil legislation and fiscal reforms and remaining challenges, see *The National Energy Report 2017*, pp. 69-73; *The National Energy Report 2019*, pp. 59-61; and *The National Energy Report 2021*, pp. 93-99.

17 For more in-depth analysis of IMC terms, see S&P Global Commodity Insights, Insight, *Kazakhstan's long-awaited Improved Model Contract for hydrocarbon exploration and production signed into law: Have conditions improved enough to spur new upstream exploration?* March 2023.

Figure 5.6 ASUT tax rates for complex offshore projects versus other projects



Source: S&P Global Commodity Insights, Kazakhstan Tax Code Article 768.

Table 5.4 Comparison of the Kazakh Energy Ministry's online auctions for E&P blocks, 2020-23 (key indicators)

Indicator	Dec 2020	Apr 2021	Nov 2021	Jul 2022	Dec 2022	Jul 2023	Totals and averages (all auctions)
Number of completed auctions*	5	8	14	13	20	9	69
Number of contracts per basin							
Precaspian	5	7	6	4	14	7	43
Turgay		1	4				5
North-Ustyurt			1	1	2		4
Mangyshlak			1	2	2	2	7
Syr-Darya			1				1
West Siberia			1				1
Ustyurt-Buzachi				2	1		3
South Turgay				4			4
Volga-Urals					1		1
Average contract license area, sq km	3,014	280	906	756	992	482	1,072
Approximate contract values**							
Average value of final contracts (for reported auction results), million USD	6	4	11	3	3	5	5
Total value of final contracts (for reported auction results), million USD	28	19	146	27	60	24	304

Notes: *Auctions that were held as planned and for which results were not later overturned due to failure of bidder to pay required bonus on time or for other reasons.

**Reported values for contracts without stipulations for possible changes in the total value depending on project work that cannot be calculated at the time of the auction; one contract (in the case of an April 2021 auction) included such a stipulation.

Source: S&P Global Commodity Insights, Ministry of Energy RK.

Table 5.5 Results of the Kazakh Energy Ministry's July 12, 2023 online auction for E&P blocks

№	Block or field name	Basin	Oblast	Area (sq km)	Final signature bonus (USD)	% change from starting signature bonus	Work requirements	Approximate value (USD)	Winner
1	Kozha South block	Precaspian	Atyrau	25	56,572	145%	1) Drilling – 1 well	2,500,000	PetroGas WK LLP
2	Shalva field	Mangyshlak	Mangystau	112	632,396	311%	1) Drilling – 2 wells	5,000,000	Ark Petroleum LLP
3	Pustynnoe field	Precaspian	Atyrau	5	3,046,426	885%	n/a	n/a	Priority Oil & Gas LLP
4	Tazhigali Southwest field	Precaspian	Atyrau	5	1,299,131	377%	n/a	n/a	Big Steps LLP
5	Oymaut block	Precaspian	Aktobe	2,187	219,325	204%	1) Drilling – 2 wells	6,000,000	Baytak Kurylys LLP
6	Tastobe block	Mangyshlak	Mangystau	90	56,300	144%	1) Drilling – 2 wells	5,000,000	Nomad West Oil LLP
7	Zhubantam field	Precaspian	Atyrau	4	181,022	95%	n/a	n/a	BlackGold Energy LLP
8	Balykshy block	Precaspian	Atyrau	1,583	1,281,034	564%	1) Drilling – 3 wells	5,500,000	Prosperity Oil & Gas LLP
9	Kumysbek field	Precaspian	Atyrau	326	592,871	671%	n/a	n/a	Big Steps LLP

Notes: Initially, the Ministry of Energy offered 26 blocks, but auctions for 17 blocks were canceled, mostly likely due to lack of bidders.
Source: S&P Global Commodity Insights, Ministry of Energy RK.

5.3.3.3 Potential to attract new investment in exploration and production

Potential additional measures by state actors that could further incentivize new investment in E&P activity include the following:

- ***A Subsoil Code amendment giving producers greater leeway to make more mid-course corrections to project implementation plans.*** For example, draft amendments to the Subsoil Code submitted to the Mazhilis (lower chamber of parliament) include a proposal to increase the threshold for divergence between planned and actual project indicators—above which project documentation must be amended—from 10% to 30% in the case of projects involving small fields.[18]
- ***Delineation of more "low-risk" exploration plays, including prospects for joint development with foreign investors.*** In line with the above-noted global trend of greater orientation around "low-risk" E&P opportunities (see Chapter 1), it may make sense to prioritize more accessible plays, including shallow-water and onshore exploration targets near known deposits. This strategy has the advantage of minimizing both risks and costs.
- ***Timely completion of plans to digitize geological data and make this available online to prospective investors.*** In November 2022, the Kaznedra Information Platform (minerals.gov.kz) began operating in pilot mode, after repeated delays, in advance of a planned full-scale launch in 2023. Electronic versions of over 30,000 geological reports are on offer, and all remaining geological materials that are not classified or confidential are supposed to become available in digital format by 2025.[19]
- ***Enactment of additional fiscal incentives for development of more challenging acreage*** (see below).

18 KPMG, Legal Alert, *Draft Law of the RK on the issues of improving the sphere of subsoil use,* June 2023, https://kpmg.com/kz/en/home/insights/2023/06/legal-alert.html.

19 Inbusiness.kz, *Natsgeosluzhba: Zagruzim vsyu geologicheskuyu otchetnost v sistemu "Kaznedra" k 2025 godu,* 1 March 2023, https://inbusiness.kz/ru/news/nacgeosluzhba-zagruzim-vsyu-geologicheskuyu-otchetnost-v-sistemu-kaznedra-k-2025-godu.

5.3.3.4 Upstream taxation conditions

Hydrocarbon producers in Kazakhstan are subject to a variety of taxes under the regular fiscal regime, while three taxes in particular account for a major share of total take for the typical producer (see Table 5.6 Taxes applicable to subsoil users in Kazakhstan in 2022):

- ***Mineral Resource Extraction Tax (MRET).*** The MRET is a royalty-like tax on crude oil and gas condensate production (and also to natural gas output); the taxable base is the value of production. The MRET ad valorem rate escalates depending on a company's annual production volume (but not price). The MRET levies for crude oil that is exported are twice as high as for domestic deliveries; i.e., a coefficient of 0.5 is applied to the MRET rate in the case of crude oil produced for the domestic market. For selected fields with challenging economics, the government sometimes grants significant MRET reductions; e.g., KMG's OzenMunayGaz subsidiary qualified for a lower rate under terms of a government resolution published in September 2016, and several other producers became eligible for reduced rates under terms of an April 2018 resolution.
- ***Crude oil export customs duty (export duty).*** The export duty on crude oil varies on a monthly basis according to a sliding scale tied to world oil prices. Kazakhstan's crude export duty rates are listed in US dollars per ton corresponding to oil price bands, and established by the Ministry of National Economy. Exports to EAEU markets are exempt from the export duty. One significant adjustment to the export duty in February 2023 was the adoption of a new oil price series for purposes of calculating the export duty rate: Kazakhstan's relatively high-priced KEBCO grade replaced Russia's Urals Blend in the tax formula. In August 2023, the methodology for calculating the export duty was also revised. Under the new procedure, the duty now varies across three oil price categories: below $25/bbl, the duty is not collected; at prices between $25/bbl and $105/bbl, the duty equates to the average market price in dollars per barrel during the previous month, levied per each metric ton of exported oil (e.g., if the price during the previous month was $25/bbl, then the export duty is $25 per metric ton); and at prices above

Table 5.6 Taxes applicable to subsoil users in Kazakhstan in 2022

Applicable tax	Rate/taxable base
Bonuses (signature)	Variable
Mineral Resources Extraction Tax (MRET)	5–18% for oil and 10% for gas
Excess profit tax (EPT)	0–60%
Rent tax on exports*	0–32%
Payment for compensation of historical costs	Variable
Excise tax on crude and gas condensate	0 tenge per metric ton
Alternative subsurface use tax (ASUT)	0–30%
Value-added tax (VAT)	1.2%
Crude oil export duty	Variable; levied per ton based on rates tied to global oil prices
Land tax	Usually immaterial for oil and gas producers
Property tax	1.5%
Environmental fees and charges	Variable
Other fees (e.g., fee for use of radio frequencies, fee for use of navigable waterways)	Variable
Other taxes and payments	Variable

Notes: *Zero tax rate if the global oil price is below $50/bbl.
Source: S&P Global Commodity Insights, Kazakhstan Tax Code, Ernst & Young LLC.

$105/bbl, one of nine different export duty rates applies depending on the price level.[20]

- ***Rent tax on exports.*** An unusual fiscal instrument in global practice, the Kazakh rent tax applies to the value of exported crude oil and gas condensate. The tax rate increases with the oil price once the price exceeds $50/bbl, ranging up to 32%. Oil exports from Kazakhstan are thus subject to two types of export taxes. In contrast to the export duty, the rent tax on exports applies to exports to EAEU markets along with other export markets.

Kazakh authorities have traditionally relied primarily on international pricing agencies for the specific price quotes used for tax calculation purposes (i.e., Platts and Argus). Going forward, however, one fiscal reform under consideration by policymakers is a change in the method for calculating the global oil price used in tax formulas whereby the average “realized price” as determined in accordance with Kazakh regulations governing transfer pricing would be used instead of quotes from pricing agencies. At the same time, Brent remains the key international benchmark oil price for use in Kazakh authorities' macroeconomic forecasts and budget planning process, and the government's outlook for Kazakhstan's socio-economic development during 2024-28 (issued in May 2023) envisages an average Brent price during this period of $80/bbl.[21]

As noted in Chapter 1, a low fiscal systems rating is one of the primary reasons for Kazakhstan's below-average score in S&P Global's E&P attractiveness ratings for hydrocarbon-producing countries. There is considerable scope for improvement of the current tax regime, including adoption of new measures targeting selected older acreage as well as greenfield projects:

- ***Fiscal stimulus measures targeting mature fields.*** For instance, KMG has embarked on a rehabilitation project involving the Uzen and Karamandybas fields and is counting on the government to approve a reduction of the MRET rate for these fields' production from 13% to 2.6%. Such a tax break would facilitate a bigger KMG spending program needed to achieve a planned production increase at the acreage in question on the order of over 500,000 tons per year by 2029. Expansion of the ASUT zone to include mature fields is another promising option for tax reform.[22]
- ***Additional tax incentives for Kazakhstan's nascent shale oil industry.*** Earlier this year, Kazakhstan's private sector South Oil company announced the discovery of a shale oil deposit that is in the Karaganda-Kyzylorda regions. South Oil has reportedly embarked on what will be the country's first shale oil development project, but S&P Global concludes that Kazakhstan is still lacking sufficient fiscal incentives for full-scale development of such reserves, particularly during the capital-intensive early project stages.[23] Tax credits were a key factor (among other enablers) in jump-starting the large-scale production of unconventional hydrocarbons in the United States, while Russian tax exemptions for shale plays have also contributed to the development of that country's shale oil industry on a more modest scale.

20 The range for export duty when prices exceed $105/bbl is from $115 per metric ton (at prices between $105/bbl and $115/bbl) up to $236 per metric ton (when prices are $185/bbl or higher).

21 As discussed in previous analysis of tax-related issues, Kazakhstan's transfer pricing legislation already has a broad impact on subsoil users, potentially applying to all cross-border transactions. For background, see *The National Energy Report 2015*, p. 219.

22 *Kazakhstan Newsline, KazMunayGas expects sharp reduction in mineral extraction tax for Ozenmunaigas/KMG*, 29 June 2023, https://newsline.kz/article/1122595/; *Kazakhstan Newsline, Kazakh fields may close without investment and alternative tax*, 15 May 2023, https://newsline.kz/article/1115182/.

23 Shale oil plays are included in the category of unconventional hydrocarbons and as such qualify for IMC terms, but this fiscal incentive is unlikely to stimulate large-scale shale oil development given the above-noted limitations of the current IMC regime.

5.4. Crude Oil Transportation

5.4.1 Existing capacity of export infrastructure

Total annual capacity of Kazakhstan's overland pipeline crude oil export system is on the order of 109.5 MMt (2.19 million b/d), including the Caspian Pipeline Consortium (CPC[24]) route (72.5 MMt or 1.45 million b/d; 78 MMt or 1.56 million b/d with drag-reducing agents), the Atyrau-Samara pipeline network (17.5 MMt, 350,000 b/d), and the Kazakhstan-China Pipeline (KCP[25]) (20 MMt, 400,000 b/d), with about half of KCP booked for Russian transit crude. There is also a small amount of rail capacity available (up to 3 MMt or 60,000 b/d) to export crude to neighboring Uzbekistan or to Russian ports on the Black or Baltic seas. Kazakhstan can export crude as well via the Baku-Tbilisi-Ceyhan (BTC[26]) pipeline from Azerbaijan, which has a nameplate capacity of 60 MMt (1.2 million b/d) and has been substantially underutilized in recent years. However, to reach Baku, crude has to be shipped across the Caspian Sea. The major constraining factor for Kazakhstan's exports on the route centers on tanker availability in the Caspian Sea and bottlenecks at the Kazakhstan's Aktau port. Other potential export routes transiting Azerbaijan are the outlets to marine terminals on Georgia's Black Sea coast: the Baku-Batumi rail route[27] or the Baku-Supsa pipeline. [28]

Given Kazakhstan's landlocked location in the heart of the Eurasian continent, export capacity has traditionally been one of the greatest challenges for oil producers in Kazakhstan. Russian routes have remained the chief outlets for Kazakh oil exports by far because all of the alternative export routes—across the Caspian Sea and through the Caucasus or eastward to mainland China—face a combination of market-driven, economic, and logistical challenges. Most of Kazakhstan's pipeline exports via Russia move through the CPC pipeline, terminating at the Black Sea terminal of Yuzhnaya Ozereyevka. Additional Kazakh oil export streams are channeled via the Russian pipeline system operated by Transneft. Kazakh crude enters the Transneft pipeline system either via the Atyrau-Samara pipeline or at Makhachkala after crossing the Caspian Sea from Aktau by tanker.

But because most Kazakh export routes involve transit through third countries, and Russia in particular, concerns about the reliability of some routes have long driven Kazakh policymakers to embrace a “multi-vectoral” strategy of multiple routes going in every direction—north, south, east, and west. Kazakhstan has intensified its oil export diversification program since February 2022 in light of the added risks associated with Russian transit—including risks of Russia's curtailment of access to the CPC and Transneft routes as well as Ukrainian attacks on tankers loading at Russian Black Sea terminals (as underscored by an August 2023 Ukrainian drone strike on a Russian oil tanker in the Black Sea). The initial focus of Kazakhstan's export diversification efforts has been on trans-Caspian shipment routes. A host of logistical and transportation cost constraints among other obstacles will nonetheless continue to limit the scale of Kazakh oil export streams bypassing Russian territory to a relatively small share of total Kazakh exports for the foreseeable future.[29]

5.4.2 Recent export trends and outlook

Kazakh oil exports fell overall in 2022 by 0.8% to 65.2 MMt (1.30 million b/d). Altogether, Russian routes handled over 95% of Kazakh oil export volumes in 2022, concentrated mainly in the CPC pipeline as well as the Atyrau-Samara routes through the Transneft pipeline system (see Figure 5.7 Kazakhstan’s oil (crude + condensate) exports via selected routes in 2022). Export trends will likely continue to largely follow the national oil production dynamic, rising slightly in 2023 and reach a maximum of 84.2 MMt (1.68 million b/d) in 2025 before dropping to around 50 MMt (1 million b/d) in 2050. The share of Kazakh oil exports transiting Russia declines significantly during the outlook period, but Russian routes are still expected to handle 79% of the total in 2050 (see Figure 5.8 Outlook for Kazakhstan's crude oil exports to 2050 by route).

European markets, the primary destination of Kazakh oil exports historically, are likely to remain important destinations over the outlook period. But Asia Pacific countries will probably take a growing share of total Kazakh oil exports going forward, given the concentration of global oil demand growth in the Asia Pacific region—involving greater exports via the Kazakhstan-China Pipeline (KCP) route and perhaps increased long-haul tanker shipments from the Black Sea and Baltic Sea ports as well.

Caspian Pipeline Consortium (CPC)

In 2022 Kazakhstan's CPC exports dipped by 0.2% to 53.5 MMt (1.07 million b/d), representing 82.1% of total Kazakh oil exports in that year. CPC continues to handle the bulk of Kazakhstan's oil exports throughout the scenario period, and through the mid-2020s CPC is likely to see a marked increase in throughput as Tengiz ramps up production and exports—facilitated in part by a $600 million CPC debottlenecking project that was completed in 2022.

24 CPC shareholders are the Russian Federation (31%; represented by PJSC Transneft with 24% and CPC Co. with 7%), Kazakhstan (20.75%; represented by KMG with 19% and Kazakhstan Pipeline Ventures LLC with 1.75%), Chevron Caspian Pipeline Consortium Co. (15%), Lukoil International GMBH (12.5%), Mobil Caspian Pipeline Co. (7.5%), Rosneft-Shell Caspian Ventures Ltd. (7.5%), BG Overseas Holding Ltd. (2%), Eni International NA NV (2%), and Oryx Caspian Pipeline LLC (1.75%).

25 The KCP segment between Atasu and Alashankou (Chinese border) is owned 50-50 by KazTransOil and the CNPC subsidiary China National Oil and Gas Exploration and Development Corporation (CNODC).

26 The BTC shareholders are BP (30.1%), SOCAR (25%), MOL (8.9%), Equinor (8.71%), TPAO (6.53%), ENI (5%), TotalEnergies (5%), Itochu (3.4%), ExxonMobil (2.5%), Inpex (2.5%) and ONGC Videsh (2.36%).

27 The Batumi terminal is owned by KMG.

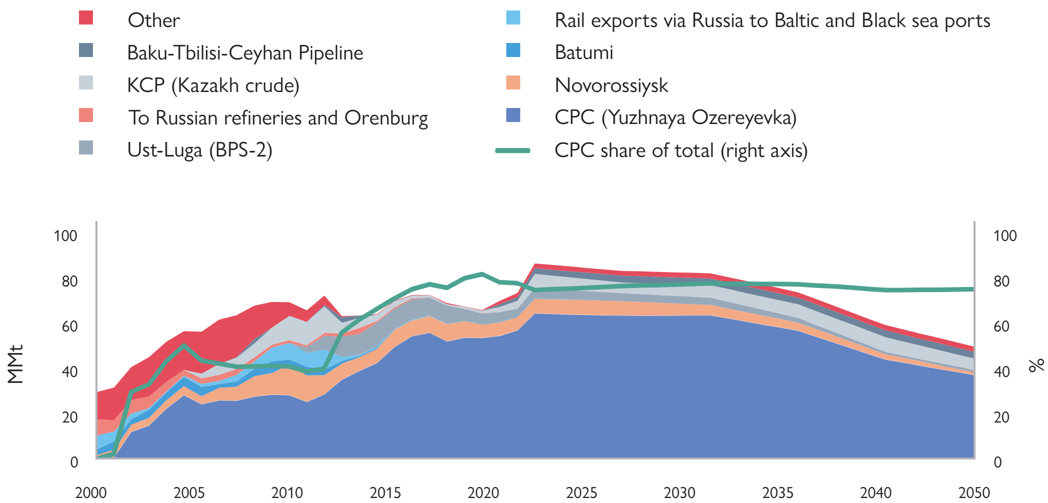
28 The Baku-Supsa pipeline is owned by the Azeri-Chirag-Guneshli consortium; its shareholders are: BP (30.37%), SOCAR (25%), MOL (9.57%), Inpex (9.31%), Equinor (7.27%), ExxonMobil (6.79%), TPAO (5.73%), Itochu (3.65%), and ONGC Videsh (2.31%). This route has never been used to export Kazakh oil, but Azerbaijan has signaled that the route is available for Kazakhstan.

29 For additional background on Kazakh oil export trends, see S&P Global Commodity Insights, Market Briefing, *Eurasian Oil Export Outlook,* April 2023; S&P Global Commodity Insights, Strategic Report, *Kazakhstan's current oil export diversification push: What role for trans-Caspian routes?* June 2023; and S&P Global Commodity Insights, Insight, *CPC weathers the fallout of Russian sanctions but does not “weather the weather”: CPC's loading terminal partially disabled from storm damage, Kazakhstan's major oil producers have few immediate alternative options for oil evacuation,* April 2022.

Figure 5.7 Kazakhstan's oil (crude + condensate) exports via selected routes in 2022

Source: S&P Global Commodity Insights upstream E&P/midsteam content (EDIN): 2010356.

Figure 5.8 Outlook for Kazakhstan's crude oil exports to 2050 by route



Source: S&P Global Commodity Insights (Eurasian Oil Export Outlook).

Several CPC incidents in 2022 suggest Kazakhstan's primary export route may not be completely reliable like it was in the past. The first was the weather-related damage to the terminal's loading hoses in March 2022. Another occurred in June 2022 when a shutdown occurred to address the issue of unexploded WW2-era ordnance in the vicinity of the CPC terminal. In July 2022, a Russian court–ordered closure of the CPC terminal—purportedly after an audit revealed "violations under the oil spill response plan"—was only narrowly averted when a regional court upheld an appeal and instead imposed an administrative fine.[30]

But barring a prolonged interruption of Kazakh oil exporters' access to CPC (not currently expected), this export route continues to enjoy a number of distinct overriding advantages—including a crude quality bank and a competitive and predictable tariff as well as some spare capacity. In short, CPC has generally been an excellent and reliable route. Kazakh shippers continue to prefer the route given priority shipping rights and attractive economics.

The net result is that CPC will likely continue to attract Kazakh oil export volumes, notwithstanding the new geopolitical downside risks. After 2025, Kazakh exports via CPC are expected to slowly contract, to the level of around 37 MMt (740,000 b/d) in 2050, or around 69% of the 2022 volume, but this still represents an estimated 75% of total Kazakh oil exports in 2050.

30 S&P Global Commodity Insights, Headline Analysis, *Russian-ordered CPC pipeline halt exposes Kazakhstan's oil export vulnerability*, July 2022.

Atyrau-Samara (Transneft) routes

Exports via the Atyrau-Samara pipeline system fell by 22.4% in 2022 to 9.4 MMt (188,000 b/d), and accounted for 14.5% of the total. Kazakhstan's 2022 exports via Transneft's Black Sea outlet at Novorossiysk—including only the pipeline deliveries from the direction of Samara and not the separate stream of Transneft pipeline deliveries from Russia's Caspian Sea Makhachkala terminal—fell by 27.2% to 4.9 MMt (98,000 b/d), while exports via the Transneft Baltic Sea outlet at Ust-Luga were down 16.5% to 4.5 MMt (90,000 b/d).

As discussed in Chapter 1, Kazakhstan's June 2022 KEBCO rebranding was instrumental in differentiating Kazakh oil export streams delivered via Transneft pipeline from Russia's Urals Blend, and thereby strengthening prices for such exports even as Urals continued to sell at a relatively steep discount to Brent. Price quotes for Kazakh oil volumes exported via Transneft routes may nevertheless be negatively impacted by increased wariness of would-be importers with respect to shipments from Russian territory (irrespective of the ultimate country of origin), while the reluctance of various shipowners to load at Russian ports may translate into increased insurance and freight costs for Kazakh exporters who ship via these terminals.

Kazakhstan began exporting oil to Germany in 2023 along another route accessed via Transneft's network—the Druzhba pipeline. Kazakh oil deliveries to Germany via the northern segment of the Druzhba began in February 2023—the first time since 2013 that Kazakhstan made use of the Druzhba export route—following agreement with Russia on transit terms. There are plans to send a total of 1.2 MMt (24,000 b/d) of Kazakh oil altogether via this route in 2023; on June 21, 2023, KMG signed an agreement for the supply of 100,000 tons per month to Germany's Schwedt refinery until the end of 2023.

Kazakh oil exports via the Atyrau-Samara outlets decline to less than half of the 2022 volume by 2050 in our base case, falling to less than 4 MMt/y (80,000) in 2050; Druzhba is expected to remain a major channel for this reduced volume (handling almost 2 MMt or 40,000 b/d in 2050), followed by Novorossiysk and Ust-Luga.

Kazakhstan-China Pipeline (KCP)

Kazakh oil exports via KCP surged by 29% in 2022 to 1.2 MMt (24,000 b/d), while total shipments in the pipeline—including Kazakh crude and, predominantly, Russian crude—rose slightly in 2022, to 11.1 MMt (222,000 b/d).[31]

In April 2023, KMG announced that the company and CNPC were considering the possibility of increasing deliveries of Kazakh oil to mainland China, and in May the two companies reportedly agreed to expand the KCP pipeline; KMG announced that Kazakhstan plans to export as much as 20 MMt/y (400,000 b/d) to China. Kazakh exports via KCP remain well below this level in our current outlook, reaching a maximum of 6.5 MMt (130,000 b/d) in 2045, before falling to 5.0 (100,000 b/d) in 2050. The KCP export route is expected to be the main alternative to reliance on Russian transit during the outlook period (though Russian volumes in KCP continue to exceed Kazakh volumes).

KCP pipeline capacity amounts to 20 MMt/y (400,000 b/d) for the eastern-most segment of the route (e.g., Atasu-Alashankou). The remainder of the pipeline is expected to be upgraded to 20 MMt/y in the coming years. Larger-scale utilization of KCP depends partly on the full reversal in flow direction of an existing pipeline that extends from Atyrau to Kenkiyak, still expected to occur sometime in the near future. In 2022, a sizable flow westward of Aktobe crude into the Atyrau-Samara pipeline continued (i.e., from Kenkiyak to Atyrau), limiting the flow eastward into the KCP pipeline. When the permanent change in flow direction is implemented, the KCP will be able to regularly access up to 6 MMt/y (120,000 b/d) of crude from the main oil-producing area in northwestern Kazakhstan. But key factors constraining a ramp-up of Kazakh volumes in KCP include relatively high transportation tariffs and a comparatively low sales price at the China border.[32]

Trans-Caspian routes

Kazakhstan's trans-Caspian oil export volumes fell to only 0.3 MMt (6,000 b/d) in 2021 (the lowest level in over two decades), but jumped nearly four-fold in 2022 to 1.2 MMt (24,000 b/d). Whereas during 2019-21 all of Kazakh trans-Caspian exports were directed into the Russian route (Makhachkala), the Russian share dropped to 72% in 2022, as Kazakhstan restarted exports via both the Baku-Tbilisi-Ceyhan (BTC) pipeline (for the first time since 2015) and the Baku-Batumi rail route (for the first time since 2017).

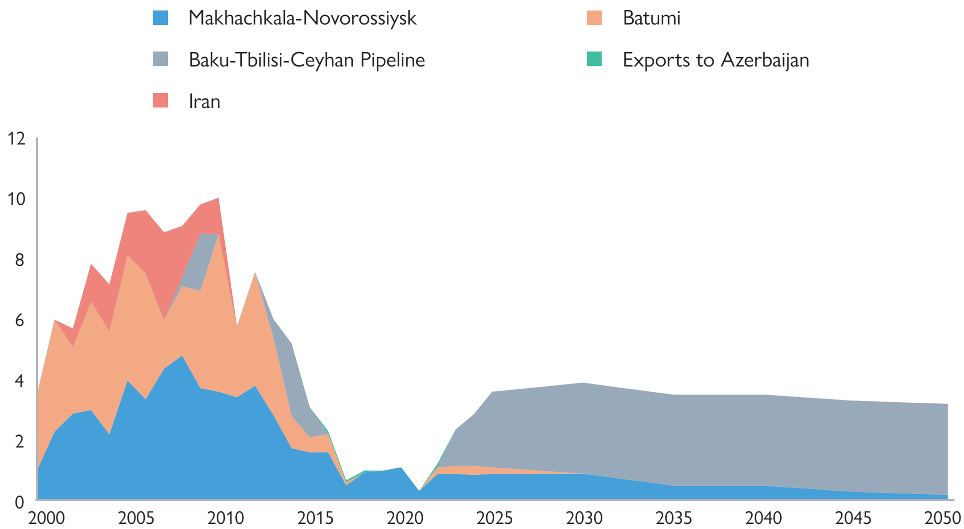
The BTC route is set to take a growing share of Kazakh trans-Caspian volumes (after carrying only 25,000 tons or 500 b/d of Kazakh oil in 2022), with implementation starting in 2023 of a 5-year KMG contract with SOCAR envisioning 1.5 MMt/y (30,000 b/d) of oil exports via BTC. KMG's trans-Caspian shipments of oil for delivery to BTC steadily ramped up in the first half of 2023, and during April-June reached 347,100 tons (or around 28,000 b/d on an annual basis). One significant change from *The National Energy Report 2021* in terms of the mix of export outlets is that we now envision the BTC pipeline as carrying Kazakh oil in our base case throughout the period to 2050.

In the base case, Kazakhstan's trans-Caspian oil export volumes reach a maximum of 3.9 MMt (78,000 b/d) in 2030, after which trans-Caspian exports gradually decline, falling to 3.2 MMt (64,000 b/d) in 2050 (see Figure 5.9 Kazakhstan's trans-Caspian crude oil exports by route in the S&P Global base case). The share of Kazakhstan's trans-Caspian oil exports channeled via non-Russian routes reaches 62% in 2023, and continues rising

31 Rosneft supplies around 5 MMt/y (100,000 b/d) to the Pavlodar refinery, and in exchange KMG delivers an equivalent volume via KCP to CNPC, with which Rosneft has a contract to supply a total of 10 MMt/y (200,000 b/d). Rosneft's contract was renewed in May 2023 through 2034.

32 The KCP route involves substantial transportation outlays because of the distance across Kazakhstan: across the Munaitas (Atyrau-Kenkiyak), Kenkiyak-Kumkol, Kumkol-Karakoin, Karakoin-Atasu, and Atasu-Alashankou pipeline segments for shippers from Atyrau and Mangystau oblasts. From Atyrau, these expenses amount to about $45 per ton, plus an additional transfer fee at Atasu of about $0.66/bbl. Although a special “unit tariff” covering the entire route is eventually planned to be introduced, there is a limit to what can be done to reduce transportation tariffs given the distances involved and the fact that different companies own and operate various segments of the KCP. Second, the border price is subject to a $5.33/bbl discount to BFOE (the Brent-Forties-Oseberg-Ekofisk crude grade) under terms of the current sales price formula. The price reflects China's internal economic calculations, and it is set to make Kazakh and Russian crude refining in inland refineries competitive against refined products derived from seaborne crude in eastern China. These two dynamics yield a fairly unattractive netback. Finally, there is a longer-term question surrounding the potential demand for additional crude oil by inland Chinese refiners that the pipeline serves. To date, it does not appear that these refiners are in position to take much larger Kazakh (or Russian) volumes.

Figure 5.9 Kazakhstan's trans-Caspian crude oil exports by route in the S&P Global base case (MMt)



Source: S&P Global Commodity Insights (Eurasian Oil Export Outlook).

throughout the period of the base case, to 94% in 2050. BTC handles the bulk of Kazakhstan's trans-Caspian shipments for the non-Russian routes as the amount going to Batumi by rail remains negligible.

5.4.3 Key obstacles to larger-scale trans-Caspian exports: Challenging economics and infrastructure constraints

Kazakh authorities have ambitions for a much larger increase in trans-Caspian oil export volumes than this; the government's target is for 20 MMt/y (400,000 b/d), and official plans in the near term include an increase of trans-Caspian oil export capacity to 15 MMt/y (300,000 b/d) by 2025. But prospects for the trans-Caspian route developing such a large export channel still seem fairly remote given the relatively unattractive netbacks on offer—compared with netbacks available from exports via the primary Russian routes in any event—and logistics constraints.

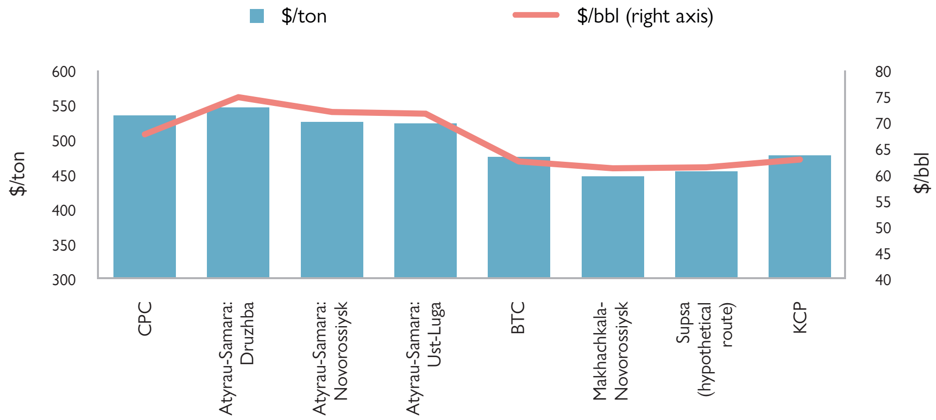
5.4.3.1 Trans-Caspian export netbacks versus the alternatives

Russia has remained the chief route for Kazakh oil exports by far because all of the alternative export routes—across the Caspian Sea and then across the Caucasus or eastward to mainland China—face a combination of marketing, economic, and logistical challenges, and the extra challenges translate into additional transportation and other costs that negatively impact export economics. In short, the CPC and the Atyrau-Samara outlets offer better export netbacks than the non-Russian alternatives. An S&P Global assessment of netbacks via selected Kazakh oil export routes from Atyrau in 2023 concluded that the CPC netback was around $534/ton ($68/bbl) and the Atyrau-Samara outlet netbacks were in the range of $522-546/ton ($72-75/bbl); the trans-Caspian route netbacks were in the range of $446-474/ton ($61-62/bbl), and a netback for KCP exports of $477/ton ($63/bbl) (see Figure 5.10 Estimated Kazakh crude oil export netbacks from Atyrau via selected routes in March 2023).

The netback available from trans-Caspian shipment fluctuates significantly over time, but some reduction of trans-Caspian transportation costs could be expected longer term given the impact of improved economies of scale, greater efficiencies, and infrastructure debottlenecking as volumes increase. But trans-Caspian route netbacks will likely remain inferior to netbacks available via Russia routes for the foreseeable future. Currently, the cost of trans-Caspian shipments is estimated at up to nearly three times the cost of CPC shipments. The single largest cost component of the overall trans-Caspian route (from Atyrau) is rail to Aktau—estimated at nearly $60/ton ($8.2/bbl) (see Figure 5.11. Estimated breakdown of transportation costs for Kazakh oil exports from Atyrau via selected trans-Caspian routes in March 2023).[33]

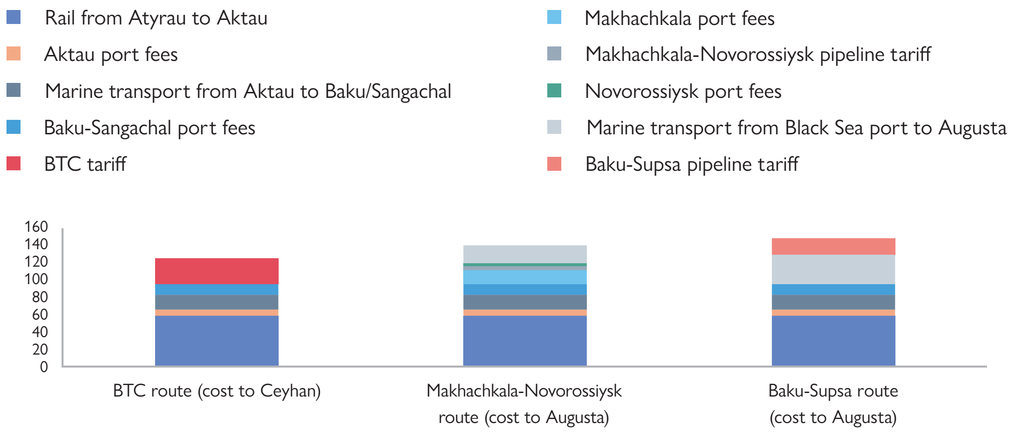
33 In the future, assuming larger volumes, this cost could be reduced significantly with the construction of a 830-km pipeline within Kazakhstan to move oil south and west. KTO's existing pipeline system carries oil in the opposite direction, from the Buzachi-Mangyshlak producing fields north to Atyrau. However, some fields, to the north and west of Aktau (e.g., Karazhanbas and Kalamkas), can access Aktau directly by KTO pipe. Such exports have a very different cost structure; not surprisingly, these producers tend to use the trans-Caspian route because of the savings in transportation expenses compared to the KTO route to Atyrau-Samara. Overland costs for them to reach Aktau are only about $3/ton ($0.4/bbl) using the KTO pipeline. Another obvious reduction in costs could come from the installation of single-point mooring buoys at the Caspian ports to facilitate loading and unloading of tankers.

Figure 5.10 Estimated Kazakh crude oil export netbacks from Atyrau via selected routes in March 2023



Notes: Netback estimates do not include calculation of taxes applying to exporters.
Source: S&P Global Commodity Insights.

Figure 5.11 Estimated breakdown of transportation costs for Kazakh oil exports from Atyrau via selected trans-Caspian routes in March 2023 ($/ton)



Source: S&P Global Commodity Insights, Argus Media Limited.

5.4.3.2 *Trans-Caspian route infrastructure issues*

Information is limited on the regional tanker capacity that can be committed to shipments via the Aktau-Baku route and estimates of available marine terminal capacity vary. But it is clear that Kazakhstan's existing Caspian tanker fleet and marine terminal infrastructure cannot currently handle trans-Caspian shipments at anywhere near the scale ultimately targeted by Kazakh authorities (and some debottlenecking of Azeri terminal facilities may also be a prerequisite for much larger volumes).

Kazakhstan's Caspian tanker fleet: Increasingly stretched

Kazakhstan's maritime shipping involves both state-owned and private companies. The leading players are evidently state-controlled Kazmortransflot (KMTF), which was established by the Kazakh government in 1998 to spearhead development of a Kazakh merchant marine fleet, and the private sector Mobilex Energy company, established in 2002. Although KMTF and Mobilex differ in key respects, the characteristics of their oil tanker fleets are quite similar. These companies' oil tankers were built by Russia's Vyborg Shipyard during 2005-06, according to the specifications of the Vympel Design Bureau in Nizhny Novgorod, and all are in the 12,000-13,000 deadweight ton (dwt) range; i.e., Caspimax-class vessels, the maximum tanker size that the relatively shallow waters of the Caspian Sea terminals can typically accommodate (it is estimated that a tanker of this size can transport about 1 MMt/y or 20,000 b/d between Aktau and Baku):

- ***KMTF's Caspian oil tanker fleet consists of three 12,400 dwt vessels: Astana (completed in 2005), Almaty (2005), and Aktau (2006).*** Earlier this year KMTF and a JV partner, UAE's Abu Dhabi Ports Group (AD Ports), purchased two additional tankers, each with a deadweight of 8,000 tons. Supplied by the Netherlands-based Damen Shipyards, the two new tankers will assist with deliveries of Tengiz oil to the BTC injection point within the framework of the above-noted KMG-SOCAR contract.
- ***Mobilex Energy owns two oil tankers of about 12,000 dwt, Kazakhstan and Abay, both built in 2005.***

Available Aktau port oil shipping data indicate that other companies are relatively minor players in this trade and probably do not add very much in aggregate to total fleet capacity.

There are several possible ways for Kazakhstan to avoid a tanker capacity crunch as trans-Caspian shipments grow: (1) buy new tankers from foreign suppliers; (2) build the necessary additional vessels in Kazakhstan; or (3) rely more on the fleet of Azerbaijan. Some combination of these options may eventually prove sufficient, but each of them involves significant trade-offs:

- ***Purchase of additional tankers is commercially risky without shipping guarantees.*** KMTF has emphasized the importance of firm commitments from would-be shippers to send larger volumes across the Caspian prior to fleet expansion. KMTF is not expected to undertake further fleet expansion without new long-term trans-Caspian shipment contracts.[34]
- ***Construction within Kazakhstan of new tankers would require setting up an entirely new manufacturing industry.*** This major investment in new manufacturing facilities is a potentially promising longer-term solution. Not surprisingly, the Energy Ministry has been a leading advocate of the domestic manufacturing option, at a proposed new plant that would produce oil tankers and other vessels, but Kazakh authorities have yet to commit to a timetable or specify financing arrangements and other key details.
- ***Increased reliance on Azerbaijan's fleet for Aktau-Baku shipments.*** The resumption of Kazakh shipments via BTC has so far reportedly involved deployment of both Azerbaijan- and Kazakh-flagged vessels, more or less on a parity basis. Azerbaijan, which has the largest fleet of any of the Caspian littoral states, may well be able to deploy more vessels going forward, but this could leave Kazakhstan inordinately dependent on foreign-flagged vessels.[35]

The main vehicle in the near term for additional expansion of KMTF's Caspian shipping capacity—and tackling Kazakhstan's Caspian logistics challenges more broadly—may be the partnership between KMTF and AD Ports (which is owned by the UAE state-owned ADQ Abu Dhabi Holding Company). In December 2022, these two entities entered into an agreement to form their current JV, known as Caspian Integrated Maritime Solutions (CIMS), aimed at delivering offshore and shipping services for energy companies active in the Caspian Sea (with a 51% stake for AD Ports and 49% interest for KMTF). Registered in February 2023, CIMS has plans to submit bids for various projects with estimated contract values of over $780 million, and the companies have also signed a seven-year vessel pooling agreement, with the aim of jointly transporting 8-10 MMt/y (160,000-200,000 b/d) of crude oil in the medium term. During March 2023 negotiations, the partners focused on the issue of expansion of the CIMS tanker fleet, to transport oil in both the Caspian Sea and the Black Sea.[36]

KMTF has apparently ruled out Russia as a source for future tanker purchases; in a 2022 interview, the executive director of KMTF, Aydar Orzhanov, stated that KMTF was unable to purchase tankers from Russian shipowners due to sanctions.[37] KMTF has a strong incentive to avoid any transactions that risk running afoul of sanctions regimes since KMTF has an international business extending well beyond Caspian waters; e.g., KMTF's 2022 business plan called for only about 0.5 MMt (10,000 b/d) of Caspian Sea oil shipments, compared with 7-8 MMt (140,000-160,000 b/d) of oil shipments elsewhere. But other Kazakh companies with less international business exposure than KMTF may have fewer qualms about buying Russian-manufactured tankers. In February 2023, it was reported that a private sector Kazakh company had purchased three tankers in the river-sea category from Russia's Volga Shipping Company, for crude and product loadings at Aktau.[38]

34 KMTF will nevertheless likely need to acquire new tankers in coming years to replace ageing vessels in its existing fleet, the average age of which is over 18 years.

35 *KURSIV, Energy Ministry wants Kazakhstan to produce oil tankers,* 4 April 2023, https://kz.kursiv.media/en/2023-04-04/minis try-of-energy-wants-kazakhstan-to-produce-oil-tankers/.

36 S&P Global Commodity Insights, *Energy Technical Report, KazMunayGaz and Abu Dhabi Ports JV to purchase additional tankers,* April 2023.

37 *SK NEWS, Glava Kazmortransflota – o nefteperevozkakh v usloviyakh sanktsionnoy voyny,* 24 May 2022, https://sknews.kz/news/view/glava-kazmortransflot-o-nefteperevozkah-v-usloviyah-sankcionnoy-voyny.

38 *Argus News & analysis, KMG to supply Tengiz for BTC,* 24 February 2023, https://direct.argusmedia.com/newsandanalysis/article/2423350.

Kazakhstan's marine terminals: Another potential bottleneck

The aggregate nameplate capacity of Kazakhstan's two existing Caspian oil terminals, Aktau and Kuryk, is estimated at around 12 MMt/y (240,000 b/d), indicating an aggregate utilization rate in 2022 of only about 10%. But there are reports of railroad constraints leading to the ports, and significant dredging operations are required at both of them before would-be shippers can make full use of the terminal facilities. Oil shipments via Aktau reached a maximum of 9.6 MMt (192,000 b/d) in 2006, but since 2010 have been well below this level, and in February 2023 the Energy Ministry estimated Aktau's crude loading capacity in the range of 5.5-7.5 MMt/y (110,000 b/d-150,000 b/d), while Kuryk's actual capacity (for ferries rather than tankers) is considerably less. In short, these terminals' existing oil loading facilities can accommodate some increase in trans-Caspian shipments above recent levels, but their limited operable capacity puts a ceiling on potential shipments in the medium term well below the amounts being targeted by Kazakh officials.

At the same time, Aktau and Kuryk terminal authorities have ambitious infrastructure expansion plans, if sufficient investment can be found:

- **Aktau.** Built in 1963, the Aktau International Commercial Sea Port is owned since 2013 by Kazakhstan Temir Zholy (KTZ), the national railway company. The port is accessible to oil producers by rail and by pipeline. A pipeline operated by KTO carries crude south from producers on the Buzachi and Mangyshlak peninsulas, while crude coming from other directions reaches Aktau by rail.[39] KMTF and other entities lease berths at Aktau (e.g., three berths are leased to KMTF under a 49-year lease). In 2022, only two out of the four terminals at the port loaded oil. Current Aktau capacity expansion initiatives include reconstruction of berths 9 and 10; these were deactivated eight years ago, but are now being put back into operation, though their utilization also reportedly depends on replacement by KTO of a pipeline segment. Altogether, the measures currently under way or under consideration, including improvements in operational efficiencies, could boost oil shipment capacity of Aktau to 17 MMt/y (340,000 b/d) according to Aktau management.[40]
- **Kuryk.** Located 70 km south of Aktau, and commissioned in 2017, Port Kuryk can handle oil and products via rail ferry. Although smaller than Aktau, Kuryk is a shorter tanker journey time to Baku, and reportedly has somewhat greater water depths than Aktau, but like Aktau also requires some deepening and expansion. There are plans to increase Kuryk's capacity to as much as 20 MMt/y (400,000 b/d). A pre-FEED study is currently under way, encompassing oil storage and loading along with other facilities, while development costs have been estimated at $50 million by port developer Semurg Invest.[41]

39 There is a peculiarity in the rail route which increases the costs of railing crude to Aktau. While KTZ owns and operates Kazakhstan's rail system, the last 17 km of rail into Aktau is owned by a private-sector Kazakh entity, Kazkortransservis; the company has charged a significantly higher tariff (per ton-km) on this segment of the route than KTZ charges on its general shipments.

40 *Kaspiyskiy vestnik, Port Aktau ne mozhet perevalit ves obyom nefti,* 3 May 2023, http://casp-geo.ru/port-aktau-ne-mozhet-perevalit-ves-obem-nefti/.

5.5 Refining and Refined Product Market Dynamics

5.5.1 Recent evolution of Kazakhstan's refined product balance

In 2022, refinery throughput in Kazakhstan rose by 5.2% to 17.9 MMt, driven by an underlying rise in domestic product demand: apparent consumption of refined products also rose by 5.2% to 15.9 MMt; aggregate product exports rose by 3.7% to 2.6 MMt, while imports dropped by 0.8% to 0.7 MMt (see Table 5.7 Kazakhstan's refined product balance).

The 2022 refinery throughput was a record volume, surpassing the pre-pandemic level (2019 throughput amounted to 17.0 MMt). Refinery output of all the primary products increased for the second year in a row in 2022. Apparent consumption of refined products in 2022 was the highest since independence. Growth continued to be concentrated in motor fuels—diesel, gasoline, and jet fuel. But mazut exports, essentially a refinery byproduct, also rose strongly in 2022; it accounted for 90% of Kazakhstan's total refined product exports.[42]

Kazakhstan likely faces an increased requirement for imports of selected refined products overall in 2023—given buoyant product demand coupled with more refinery maintenance and unplanned July 2023 stoppages at two major plants that look likely to keep refinery throughput fairly sluggish. Kazakhstan's total 2023 product import needs (announced by the Energy Ministry in February 2023) already was expected to be 700,000 tons of diesel and 300,000 tons of jet fuel imports (compared with diesel and kerosene imports in 2022 of around 200,000 tons and 100,000 tons, respectively). Kazakh refined product balance dynamics during January-June point to overall market tightness for these two middle distillate products (see Table 5.8 Key trends for Kazakhstan's main refined products in the first six months of 2023).[43]

41 S&P Global Commodity Insights, Platts Oilgram News, *INTERVIEW: Kazakh port developer Semurg Invest offers 'Plan B' for country's crude exports,* April 2023.

42 The United Arab Emirates overtook the Netherlands as the primary destination of for Kazakh mazut exports in 2022, importing 1.0 MMt.

43 Another product in relatively short supply domestically is bitumen; in his September 2022 State of the Nation address, President Tokayev drew attention to the need to overcome a national bitumen deficit, and in July 2023 Kazakhstan reached an agreement with Russia to triple annual imports of road bitumen (to 300,000 tons per year). See *Kazakhstan Newsline, Bitumen supplies from Russia to Kazakhstan increase to 300,000 tonnes per year,* 21 July 2023, https://newsline.kz/article/1124878/.

Table 5.7 Kazakhstan's refined product balance (MMt)

	2015	2016	2017	2018	2019	2020	2021	2022	Percent change 2021-22
Throughput	14.5	14.5	14.9	16.4	17.0	15.8	17.0	17.9	5.2
Output of products (reported)	13.5	12.9	13.0	13.4	14.0	12.6	13.8	14.9	7.9
Diesel fuel	4.6	4.7	4.4	4.7	5.0	4.7	5.0	5.4	8.5
Gasoline	2.9	3.0	3.1	4.0	4.5	4.5	4.8	5.0	3.1
Kerosene	0.3	0.3	0.3	0.4	0.6	0.4	0.6	0.7	14.7
Mazut	4.1	3.2	3.4	3.2	3.1	2.4	2.8	3.3	17.9
fleet	0.3	0.2	0.0	0.3	0.2	0.2	0.2	0.2	1.1
furnace fuel	3.8	3.0	3.4	2.9	2.9	2.3	2.6	3.1	19.2
Lubricants	---	---	---	---	---	---	---	---	---
Other	2.6	3.4	3.8	4.1	3.8	3.8	3.8	3.5	-7.2
Bitumen	0.6	0.6	0.8	0.6	0.7	1.0	1.0	0.9	-10.6
Petroleum coke/other residual	0.9	0.9	1.3	1.5	1.6	1.7	1.6	1.5	-4.0
Losses and fuel as % of throughput	6.4	11.1	12.8	18.3	17.6	20.2	18.7	16.6	-10.8
Consumption (apparent)									
Total (all refined products)	11.5	12.5	12.9	14.7	14.7	14.4	15.2	15.9	5.2
Diesel fuel	4.6	5.1	4.7	4.9	5.2	5.2	5.1	5.5	7.2
Gasoline	4.3	4.1	4.1	4.5	4.5	4.0	4.7	5.0	5.7
Kerosene	0.3	0.3	0.5	0.6	0.6	0.5	0.6	0.8	19.6
Mazut	0.1	-0.2	-0.4	0.3	0.5	0.9	0.7	0.9	26.4
Other	2.2	3.2	4.0	4.4	3.9	3.9	4.0	3.8	-4.2
Exports									
Total (all products)	4.9	3.9	4.0	3.4	2.8	2.3	2.6	2.6	3.7
Diesel fuel	0.2	0.1	0.1	0.2	0.0	0.1	0.2	0.1	-46.7
Gasoline	0.0	0.0	0.0	0.0	0.1	0.5	0.1	0.0	-76.0
Kerosene	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-14.1
Mazut	4.0	3.4	3.8	3.0	2.6	1.6	2.1	2.4	14.7
Other	0.6	0.4	0.1	0.1	0.1	0.1	0.1	0.1	-23.0
Imports									
Total (all products)	1.9	1.9	2.0	1.7	0.5	1.0	0.7	0.7	-0.8
Diesel fuel	0.2	0.4	0.5	0.5	0.2	0.7	0.3	0.2	-47.4
Gasoline	1.4	1.1	1.1	0.6	0.0	0.0	0.0	0.0	3,508.3
Kerosene	0.1	0.1	0.2	0.2	0.0	0.0	0.1	0.1	56.7
Mazut	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	-86.7
Other	0.2	0.2	0.3	0.3	0.2	0.3	0.3	0.3	29.7

Source: S&P Global Commodity Insights, Ministry of Energy RK, Bureau of National Statistics RK.

Table 5.8 Key trends for Kazakhstan's main refined products in the first six months of 2023 (thousand metric tons)

	Jan-Jun 2022	Jan-Jun 2023	Percent change
Output of products (reported)			
Diesel fuel	2,700.3	2,773.3	2.7
Gasoline	2,471.5	2,585.5	4.6
Kerosene	360.6	298.8	-17.1
Mazut	1,648.5	1,558.3	-5.5
Consumption (apparent)			
Diesel fuel	2,677.7	2,952.5	10.3
Gasoline	2,471.2	2,587.9	4.7
Kerosene	389.6	436.3	12.0
Mazut	603.0	270.6	-55.1
Net exports			
Diesel fuel	22.6	-179.2	-893.9
Gasoline	0.3	-2.4	-904.5
Kerosene	-29.0	-137.5	374.8
Mazut	1,045.5	1,287.7	23.2

	Jan-Jun 2022	Jan-Jun 2023	Percent change
Exports			
Diesel fuel	44.6	52.8	18.4
Gasoline	0.9	0.0	-100.0
Kerosene	3.8	6.7	77.5
Mazut	1,045.5	1,287.7	23.2
Imports			
Diesel fuel	22.0	232.0	954.0
Gasoline	0.6	2.4	300.4
Kerosene	32.7	144.1	340.7
Mazut	0.0	0.0	-100.0

Source: S&P Global Commodity Insights, Bureau of National Statistics RK.

Table 5.9 Output of primary refined products by the major Kazakh refineries (MMt)

	2018	2019	2020	2021	2022	Percent change 2021-22
Shymkent						
Crude throughput	4.8	5.4	4.8	5.2	6.2	20.2
Motor gasoline	1.3	1.9	2.0	1.9	2.1	10.5
Diesel	1.2	1.5	1.4	1.6	1.9	24.3
Jet fuel	0.3	0.3	0.2	0.3	0.3	15.8
Mazut	0.8	0.7	0.3	0.6	1.0	60.7
Pavlodar						
Crude throughput	5.3	5.3	5.0	5.4	5.5	1.4
Motor gasoline	1.4	1.4	1.4	1.5	1.6	4.4
Diesel	1.7	1.8	1.6	1.7	1.8	5.2
Jet fuel	0.1	0.2	0.1	0.2	0.2	11.9
Mazut	0.6	0.6	0.5	0.6	0.6	7.2
Atyrau						
Crude throughput	5.3	5.4	5.0	5.5	5.2	-4.6
Motor gasoline	1.2	1.2	1.1	1.4	1.3	-7.4
Diesel	1.5	1.5	1.5	1.6	1.5	-5.9
Jet fuel	0.0	0.1	0.1	0.1	0.1	10.1
Mazut	1.1	1.2	1.1	1.2	1.2	1.7

Source: S&P Global Commodity Insights, KMG.

5.5.2 Overview of key trends at the three major plants

Kazakhstan's three major refineries—Shymkent, Pavlodar, and Atyrau—accounted between them for 94.4% of Kazakh refinery throughput in 2022; these plants are the key sources of light products. Shymkent, which is now the biggest refiner, increased throughput by 20.2% to 6.2 MMt in 2022, and was the primary producer of gasoline, diesel, and jet fuel in Kazakhstan in 2022. Pavlodar also raised throughput in 2022, but by only 1.4% to 5.5 MMt, while Atyrau's throughput contracted by 4.6% to 5.2 MMt; Atyrau produces the largest volume of mazut among Kazakhstan's refineries (see Table 5.9 Output of primary refined products by major Kazakh refineries).

Although domestic markets remained generally well supplied by refiners in 2022, periodic shortages still occurred for certain products and regional markets; maintenance at the Shymkent and Atyrau plants was rescheduled to avoid this and meet burgeoning domestic demand. All three of the larger refineries were slated for scheduled maintenance over the course of 2023, with expected tightness in some product markets exacerbated by unplanned outages. In particular, during part of July, national refinery throughput fell by nearly half due to planned and unscheduled stoppages at the major plants.[44]

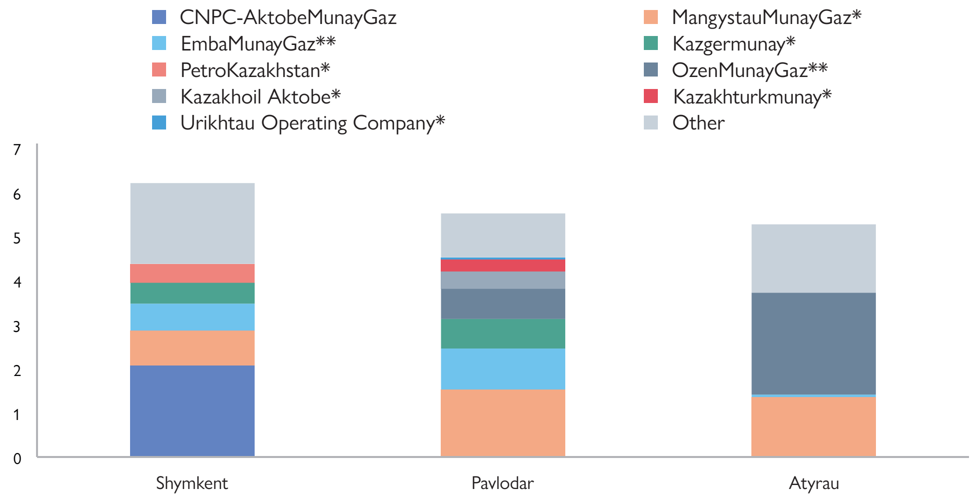
Aggregate annual nameplate distillation capacity of the three major refineries currently amounts to 17.5 MMt—6.0 MMt at Shymkent and Pavlodar, and 5.5 MMt at Atyrau. But all routinely have run above capacity during some months each year. The effective capacity is over 6.5 MMt/y for both Shymkent and Pavlodar, while Atyrau has routinely run over 450,000 tons/month, and up to 500-510,000 tons/month, implying an effective capacity of nearly 6 MMt/y. All three plants are intent on expanding and/or or upgrading existing distillation capacity. Kazakh authorities' plans for expansion of national refining capacity center on Shymkent, given the concentration of domestic demand growth in southern Kazakhstan, and in May 2023 President Tokayev announced that Shymkent's capacity will be doubled, to 12 MMt/y. The government is also intent on further boosting diesel yield at Pavlodar: a joint venture between KMG and France's Air Liquide plans to build a hydrogen unit at the Pavlodar plant with the aim of producing 160,000 tons per year of winter diesel, and this project underscores how important it is for Kazakhstan not to be dependent on (Russian) imports of diesel—notwithstanding the EAEU integration process and even though it may be more expensive to manufacture additional diesel locally than to import the product from Russia. With respect to the Atyrau refinery, priorities include expansion of plant capacity by 1.2 MMt/y and development of power generation; Kazakh authorities called for acceleration of plans to build a gas turbine plant after the July 2023 power disruption.

Both Pavlodar and Atyrau are currently relatively well supplied with KMG-produced crude, although Pavlodar receives this as Russian crude that is delivered to the plant under a Rosneft-CNPC swap arrangement whereby KMG delivers an equivalent volume of Kazakh crude to CNPC via the Kazakhstan-China Pipeline.[45] The bulk of crude processed at the Shymkent refinery comes from non-KMG assets, mainly JVs and independent producers in Aktobe and Kyzylorda oblasts; the refinery's single largest supplier in recent years has been CNPC-AktobeMunayGaz, accounting for around a third of the plant's total crude supplies in 2022 (see Figure 5.12 Crude oil deliveries to major Kazakh refineries by producer in 2022).

44 *See Kazakhstan Newsline, Oil refining in Kazakhstan decreases by almost half,* 10 July 2023, https://newsline.kz/article/1123478/; *Kazakhstan Newsline, Shymkent refinery in Kazakhstan ready to operate as usual,* 19 July 2023, https://newsline.kz/article/1124675/.

45 Located near Kazakhstan's northeastern border with Russia, the Pavlodar refinery sources its crude from Russia because of the relative logistics. Producers in western and south-central Kazakhstan send volumes (nominally) to the Pavlodar refinery as part of the swap arrangement with Rosneft on that company's exports to China; i.e., Kazakh crude recorded as deliveries to Pavlodar physically is directed to China within the framework of the Rosneft-CNPC swap deal, and the Pavlodar refinery processes Russian crude. Kazakh producers are still responsible for covering the hypothetical costs for transportation to Pavlodar rather than to Alashankou.

Figure 5.12 Crude oil deliveries to major Kazakh refineries by producer in 2022 (MMt)



Notes: *KMG JV; **KMG fully-owned subsidiary.
Source: S&P Global Commodity Insights, KMG.

5.5.2.1 Feedstock supply issues

Each major plant faces feedstock supply risks during the outlook period, given the ongoing decline of legacy crude production at fields that have traditionally supplied them. This ultimately translates into a crude supply challenge for Kazakh policymakers since it is the Energy Ministry that determines the schedule for crude supplies to refineries under the current system. Shymkent appears particularly vulnerable, as it does not have a readily available alternative crude supply source to replace its traditional sources, while at the same time Shymkent is also the refinery that is most "exposed" to the concerns of independent producers. Their crude deliveries to the refinery (at reduced domestic prices) can involve relatively high transportation costs (some crude deliveries to Shymkent must be shipped as much as 2,000 km, incurring transportation costs on the order of $24/ton from Atyrau). The relatively great dependence of Shymkent on independents for feedstock supply also leaves the plant especially vulnerable to negative knock-on effects of artificially-low domestic prices on suppliers; i.e., whereas KMG may in theory offset losses on domestic sales with revenue from its higher-priced export streams, the independents traditionally have less access to export markets, with the result that they are more likely to cut back upstream spending and ultimately domestic deliveries if domestic prices fail to cover costs and provide a return on investment.

All three plants still operate on a tolling basis that serves as means to finance the $6 billion modernization program during 2014-18, but tolling may not be optimal longer term given the refineries' crude supply needs. Under the tolling system, crude suppliers pay refiners a fee to process the crude, and retain title to the resulting refined products for subsequent sale. The processing tariffs for the three major refineries are established by KMG for the Atyrau and Pavlodar plants, and by the board of directors of PetroKazakhstan for Shymkent. In 2022, the processing tariff reached $91.7/ton for Atyrau, $50.1/ton for Pavlodar, and $76.2/ton for Shymkent. KMG's outlook is for tariffs for all three refineries to remain flat (in tenge terms) through 2026. Kazakh refiners have little incentive to alter the current tolling scheme over the next decade or so as they pay back sizable loans for their previous modernizations. The tolling system tends to insulate refiners from market forces, with the result that plants may lack incentive to improve efficiencies further. So as the loans are paid off, there is growing reason for Kazakhstan to consider a more market-oriented business model whereby refiners function as merchant operators who buy crude oil feedstock and sell finished refined products (as in other EAEU states and most of the rest of the world).[46]

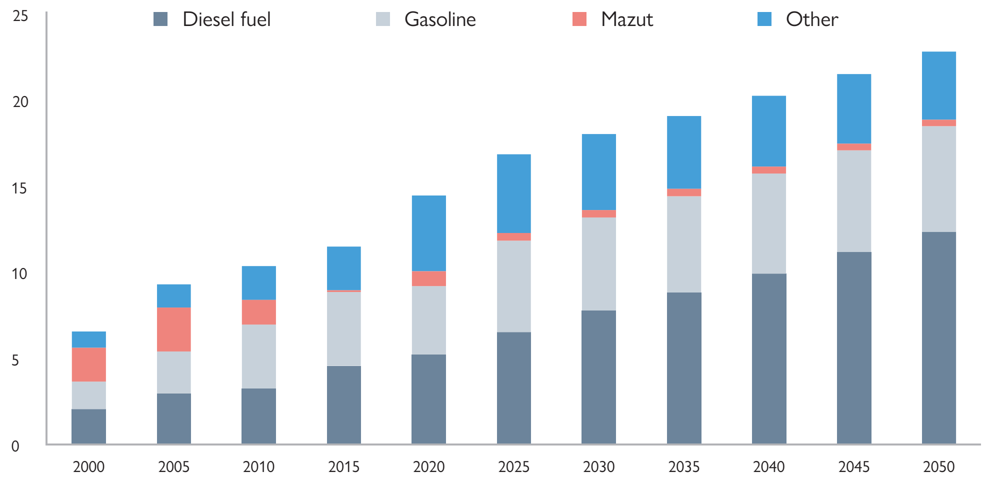
5.5.3 Outlook for Kazakhstan's refined product balance

Our base-case scenario is for an ongoing rise in refinery throughput out to 2050, lifting the total by around 24% to 22.3 MMt, in order to meet most of a continued expansion in domestic apparent refined product demand (projected to be about 43.0% higher at 22.8 MMt—much of it concentrated in diesel (see Figure 5.13 Outlook for apparent consumption of refined products in Kazakhstan). The base case has Kazakhstan becoming a net importer of refined products by 2045, with net imports of about 0.5 MMt in 2050; imports consist mainly of diesel during 2023-50, while during the outlook period Kazakhstan also increases exports of certain products, notably gasoline. We expect the transportation segment in particular to be a major incremental consumer of refined products longer term, as diesel-engine vehicles as well as vehicles with engines that run on gasoline (and LPGs) will continue to dominate the fleet.

One key implication is that significant expansion of existing refining capacity is needed. Regionally, the pattern of product demand growth indicates that a sizable expansion of annual throughput capacity at Shymkent for crude distillation—by 3 MMt to 9 MMt—is required during the period (late 2020s or early 2030s). Meanwhile, only minor "capacity creep" is needed at Pavlodar and Atyrau, through selective debottlenecking and improvement of operational efficiencies. As noted above, the Kazakh government envisions a larger-scale expansion of annual

46 For additional background on domestic crude oil and refined product market and pricing dynamics, see Chapter 3 above as well as *The National Energy Report 2021*, pp. 109-112, and *The National Energy Report 2019*, pp. 69-71.

Figure 5.13 Outlook for apparent consumption of refined products in Kazakhstan (MMt)



Source: S&P Global Commodity Insights.

Shymkent capacity in the medium term—by 6 MMt to 12 MMt. In either scenario, however, southern Kazakhstan product demand growth may exceed regional product supply. We expect southern Kazakhstan will continue to have a regional deficit of products overall, but the gap can be met with surplus products from other regions/plants (mainly Atyrau), while a net deficit of products is expected to emerge in north-central Kazakhstan as well. Southern Kazakhstan and north-central Kazakhstan experience deficits of gasoline and diesel (relative to regional production) during most of the outlook period.

In parallel with overall capacity expansion, further improvements are needed in the quality of selected products. With refinery modernization, Kazakh refineries already mainly produce fuel with K-4 (Euro-4) and K-5 (Euro-5) specifications, but all motor fuel should eventually meet K-5 standards, resulting in a reduction in sulfur emissions from the K-4 level of 50 parts per million (ppm) to 10 ppm.

5.5.4 Sensitivity of the domestic demand trajectory to the progress of market reforms

The above-noted base case for domestic consumption assumes continued liberalization of domestic crude and product prices, with the result that average price levels reach netback parity by around 2030. This means crude producers in Kazakhstan are incentivized to deliver sufficient feedstock supplies to Kazakhstan's refineries at export-parity prices, and refiners have sufficient incentive to direct the bulk of their products to domestic markets (while directing some surplus to export markets). But this outcome is by no means guaranteed, and in the absence of such price reform, domestic product demand will likely be higher than in the base case.

Price regulation is not only a problem for Kazakh crude producers (who in effect subsidize artificially low consumer prices at the pump through crude oil sales at prices well below world market levels), and for refined product market players in Kazakhstan (given the extremely limited retail markup). As noted in Chapter 3, the resulting market distortions ultimately raise energy security issues for Kazakhstan because they give rise to "grey" exports involving the unauthorized outflow of Kazakh refined products from border regions to neighboring countries with significantly higher product prices, such as Russia and Kyrgyzstan.[47]

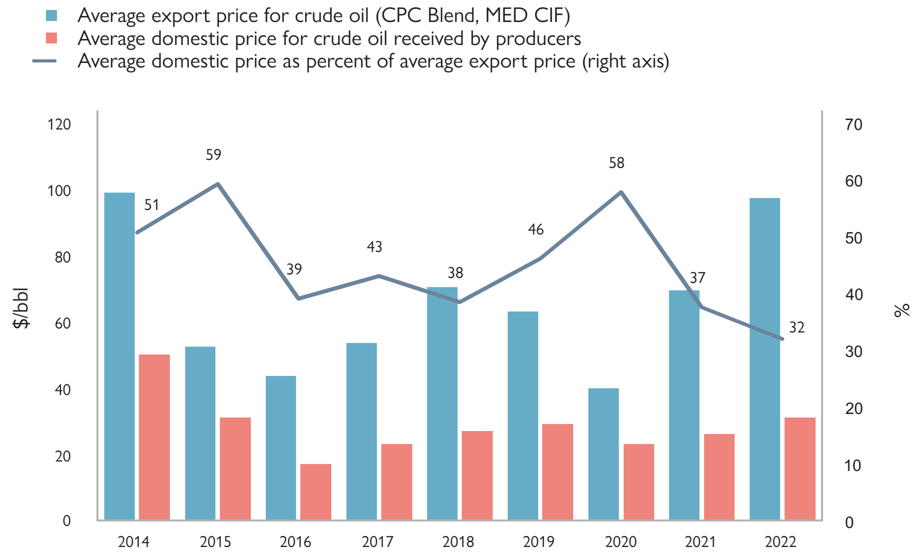
Kazakhstan officially liberalized AI-92 and AI-93 gasoline prices in September 2015, and diesel prices in July 2016, while at the same time maintaining regulated retail prices for AI-80 gasoline (used mostly in the agricultural sector). But all domestic motor fuel prices have since remained heavily administered in Kazakhstan notwithstanding official price liberalization. Meanwhile, the average domestic price for crude oil is typically even lower than average domestic product prices in relation to comparable international benchmarks. In 2022, the average domestic crude oil price received by producers amounted to only around 32% of the level of the average price for Kazakhstan's primary oil export stream—down from 37% in 2021 (see Figure 5.14 Comparison of domestic Kazakh and international crude oil prices). Domestic deliveries nevertheless still tend to generate positive margins, due largely to lower transportation costs (relative to exports) and a lower MRET rate.

The January 2022 events temporarily reversed the prior impetus for higher domestic prices through liberalization; in the wake of the mass protests, the government decreed a freeze on gasoline and diesel as well as LPG prices. In January 2023, the government decreed a prolongation of state regulation of motor fuel prices indefinitely, although Prime Minister Alikhan Smailov also stated that his government was committed to the gradual transition to market-based regulation of refined product prices.

Subsequently, Kazakh authorities have begun raising the ceiling on gasoline and diesel prices, and in August 2022 instituted a two-tiered retail diesel price system whereby foreign citizens are required to pay higher prices for diesel than Kazakh citizens—in an effort to combat the chronic problem of cross-border "leakage" and "grey" market sales.

47 The price differentials incentivize the redirection of Kazakh motor fuels to consumers in neighboring states in a variety of forms, including personal use, resale, and transit. Anecdotal evidence suggests significant "grey" exports in both diesel (for trucking) and gasoline (by cars) in recent years. For example, S&P Global estimates that in addition to ~150,000 tons per year of diesel that are used for legitimate transit, another ~150,000-200,000 tons are likely involved in the "grey" export trade in Kazakhstan.

Figure 5.14 Comparison of domestic Kazakh and international crude oil prices



Source: S&P Global Commodity Insights, KAZENERGY.

As noted above (see Chapter 3), in April 2023 the government raised the maximum allowable AI-92 retail gasoline price (to 205 tenge or around $0.45) per liter. During the same month the government decreed a continuation of the overall differentiation of retail diesel prices instituted previously and simultaneously raised the maximum allowable diesel price for Kazakh citizens within this system. Specifically, the April 2023 decree established the following retail diesel price parameters:

- Kazakh citizens[48]: 295 tenge ($0.65) per liter, up to specified volumes, depending on the vehicle type; i.e., up to 100 liters per day in the case of light vehicles, and up to 300 liters per day for trucks, buses, and other specialized automobiles.
- Foreign citizens, as well as Kazakh citizens in the case of diesel purchases in quantities that exceed the above-noted limits: 450 ($1) tenge per liter.

Comprehensive data are lacking on the impact on cross-border diesel flows of the differentiation of diesel prices, but anecdotal evidence suggests that border "leakage" of diesel remains an ongoing issue in southern Kazakhstan—pointing to the challenges in practice of liberalizing prices.

Policymakers have signaled their commitment in principle to more far-reaching motor fuel price reforms. For example, in June 2023 a proposal to tie gasoline prices in Kazakhstan to world price quotes for oil and/or refined products was announced by Kuat Asambekov, the deputy director of the Fuel and Energy Complex of the Agency for the Protection and Development of Competition. But no schedule for price changes has yet been indicated, while Asambekov has emphasized that any such reform would be implemented in different phases.[49]

Two key developments expected during the mid-2020s are nevertheless likely to compel policymakers to undertake further liberalization of domestic oil prices:

- ***The imperatives of EAEU oil market integration.*** The pending launch of the EAEU common market in oil and oil products in 2025 means that it will be difficult for Kazakhstan to continue to resist the pull of market forces, and its domestic prices will eventually be pushed or pulled into parity with its neighbors (see Chapter 3). Russia is the largest EAEU producer, consumer, and exporter of refined products and Russian market dynamics will therefore likely play a decisive role in determining overall EAEU market outcomes. Russia's product prices are generally based on export parity; its export duty and transportation costs act as wedge between domestic prices and export prices, but the Russian export tax is being phased out by 2024 as part of wider fiscal reform.
- ***The tightening of Kazakhstan's crude oil balance as aggregate production begins to decline while domestic demand continues to rise.*** One of the most critical drivers of domestic price liberalization is the expected tightening supply of crude oil after 2025. As noted above, Kazakh oil production is expected to reach a maximum in about 2025 and then begin to decline, but domestic crude oil demand remains on an upward trajectory, given rising domestic product consumption. Moreover, the production decline is likely to be initially concentrated in various legacy KMG fields that have traditionally been a mainstay of Kazakh refinery feedstock supply.

Along with removal of price controls, additional reforms of crude oil and product market structures could go far to ensure that domestic product demand is adequately supplied by Kazakh refiners during the outlook period. Under the current system, subsoil users sell crude oil for the domestic market (domestic refineries) via direct contracts with crude supplier-traders; there is currently no centralized exchange in place. The crude supplier-traders (in Russian, *davaltsy*), in turn, obtain refined products through the above-noted tolling arrangements, and their remuneration comes when they sell the basket of petroleum products they receive from the refinery for the crude they supply—to retailers and secondary wholesalers at ex-refinery

48 Technically, the decree limits diesel sales at the discounted prices to holders of a Kazakh driver's license or certificates of vehicle registration in Kazakhstan, but in practice this basically means Kazakh citizens.

49 *LS, V Kazakhstanye predlagayut privyazat tseny na GSV k nefti,* 22 June 2023, https://lsm.kz/v-kazahstane-predlagayut-ceny-na-gsm.

wholesale prices. The crude supplier-trader is the middleman and appears to add little if any value compared with other key players in the value chain.

Seeking to reduce the number of unnecessary market participants, the Energy Ministry and the Agency for Protection and Development of Competition have considered reforms that would exclude intermediaries from operating in the refined product distribution segment if they: (1) lack ownership rights to oil production/processing/sale of petroleum products or (2) lack ownership of oil depots or filling stations. To date these proposals remain on paper, but there are signs that Kazakhstan's main refineries are looking to reduce the role of intermediaries. Specifically, in April 2023 the Energy Ministry reported that the Atyrau refinery had begun to reverse an earlier outsourcing process, with the result that plant management has begun to assume responsibility for a wide range of activity along the value chain that had previously been delegated to intermediaries, including service and repair shop activities, railway operations, and freight shipments; the Pavlodar and Shymkent plants have reportedly undertaken similar measures.[50] Exchange trading of refined products is also slated to increase, which should further reduce the role of these intermediaries; the Energy Ministry has estimated that the share of exchange trading in petroleum products in Kazakhstan will gradually rise from around 10% of output in December 2022 to 15-20% during 2023-24.

Notwithstanding such positive signs, the risk remains that pricing and market reforms will not proceed quickly enough to incentivize the needed changes. In an alternative pricing scenario, where domestic prices remain depressed below market parity, domestic demand rises more robustly and there are more cross-border flows and higher transit-related fuel consumption. In this scenario, Kazakh policymakers continue to rely on the current mix of administrative measures to control the domestic refined product market. Meeting a higher level of aggregate product demand also means more refinery expansion and more refinery upgrades than assumed in our current base case, and poses more of a dilemma in securing crude supply for the refineries.

5.5.5 Key dynamics for selected refined products

This section looks in more detail at major refined product balance trends for the main refined products consumed in Kazakhstan, starting with diesel fuel and kerosene—two key products that have been in relatively short supply domestically in recent years—followed by discussion of gasoline and mazut balance dynamics.

5.5.5.1 Diesel

Diesel is the single largest component (product) in Kazakhstan's refinery slate and in its domestic consumption balance. Widely consumed in Kazakhstan, diesel is used across many economic sectors, while the transportation sector (trucking) is the single largest consumer. In their role as distributors, Petrosun and KMG are the key suppliers of diesel fuel to the domestic market. Demand is mostly met with domestic production, but Kazakhstan remained a net importer of relatively small diesel volumes each year during 2016-22.

In 2022, diesel output increased by 8.5% to 5.4 MMt; there was a 7.2% rise in apparent demand to 5.5 MMt, while imports fell by 47.4% to 178,000 tons, and exports declined by 46.7% to 119,000 tons (see Figure 5.15 Kazakhstan's diesel balance, 2015-22). The 2022 jump in domestic diesel demand probably reflected a combination of further pandemic recovery, higher underlying economic growth, as well as extra cross-border traffic. Demand has also been supported by growing cargo traffic through Kazakhstan. During the first part of 2023 Kazakh refinery output of diesel continued to fall short of domestic demand; in January-June 2023, diesel output rose by only 2.7% to 2.8 MMt, but domestic consumption surged by 10.3% to 3.0 MMt; imports increased several-fold in the first six months to 232,000 tons, while exports rose by 18.4% to 53,000 tons.

In the S&P Global base case, diesel output increases quite strongly during 2023-50, rising by 90% to 10.3 MMt in 2050; consumption, though, increases by 126% to 12.3 MMt. Imports become increasingly necessary during the outlook period, with net diesel imports reaching 2.1 MMt in 2050. We expect trucking (including transit)−tied to underlying GDP growth and the need to move goods−to drive the bulk of the rise in domestic diesel demand. Other segments of demand (e.g., agriculture, industry) grow more slowly.

5.5.5.2 Kerosene

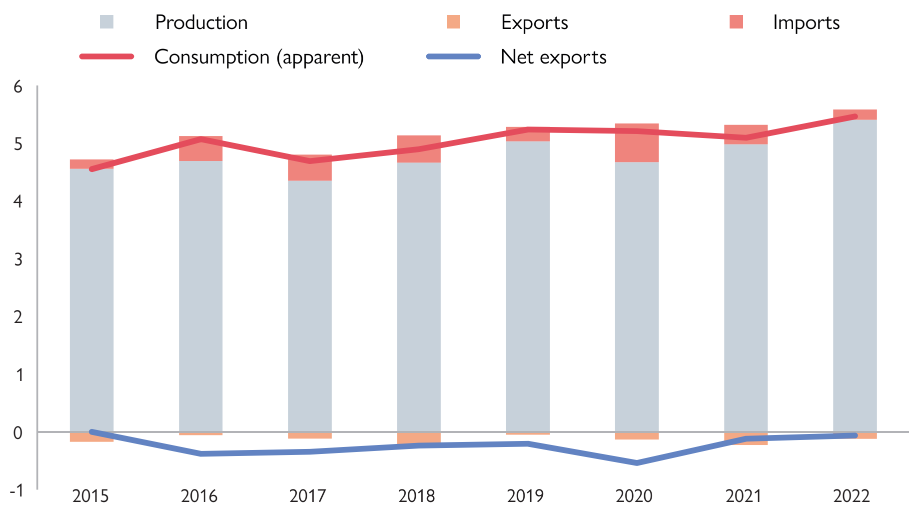
Traditionally a net importer of kerosene (mostly jet), Kazakhstan has approached self-sufficiency at times following refinery modernization; domestic production satisfied over 85% of consumption in 2022, up from less than 60% in 2016. Jet kero is consumed in the civil and military aviation segments, and demand has expanded rapidly since 2015 with the proliferation of tourism and expansion of air travel in Kazakhstan—growing by an annual average of about 10% during 2016-22 (even after factoring in the nearly 30% drop in 2020). Regionally, demand is concentrated in southern Kazakhstan (where the Almaty hub is a key demand center). The Energy Ministry and the Ministry of Industry and Infrastructural Development determine jet kero allocations for airlines on a monthly basis.

Based on Kazakhstan's Bureau of Statistics data, total kerosene (mostly jet) production in Kazakhstan rose by 14.7% in 2022 to reach a new historical maximum of 673,000 tons, while apparent demand jumped by 19.6% and also reached a new record level, of 762,000 tons; imports rose by 56.7% to 101,000 tons, while exports remained negligible at 12,000 tons (see Figure 5.16 Kazakhstan's kerosene balance, 2015-22). Kazakhstan's imports of kerosene will be even higher in 2023, as production has failed to match increases in consumption. But Kazakh authorities actually banned the import of jet kero from Russia during part of the summer, claiming that an oversupply had resulted in overstocking risks and a reduction of Kazakh refinery output of the product. During January-June 2023, jet kero output contracted by 17.1% to 299,000 tons while consumption rose 12.0% to 463,000 tons; imports jumped 340.7% to 144,000 tons.

Precise data are lacking on the breakdown of Kazakhstan's jet fuel production among different grades recently, but the ambition is to expand production of Jet A-1 fuel grade, aimed at serving the higher number of international flights and boosting Kazakhstan's

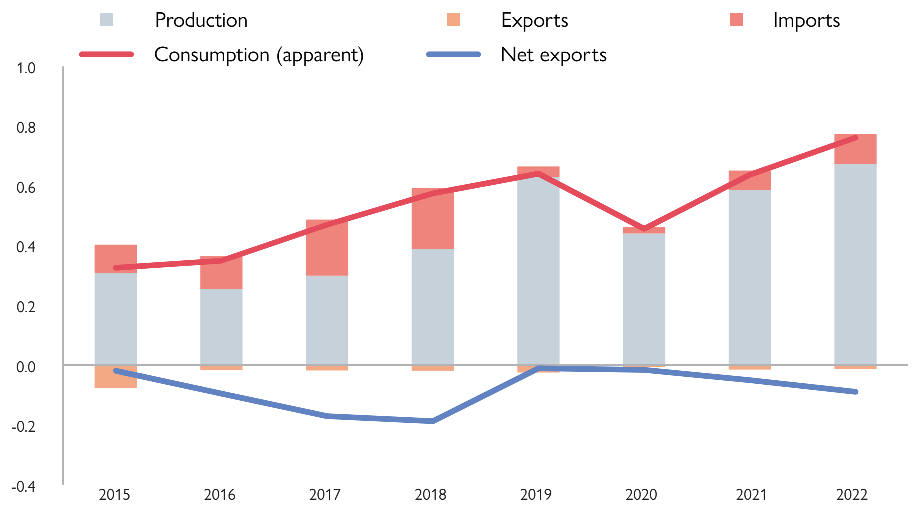
50 *LS, V Kazakhstanye nashli sposob izbavit NPZ ot posrednikov,* 5 April 2023, https://lsm.kz/v-kazahstane-pridumali-kak-izbavit-npz-ot-posrednikov.

Figure 5.15 Kazakhstan's diesel balance, 2015-22 (MMt)



Source: S&P Global Commodity Insights.

Figure 5.16 Kazakhstan's kerosene balance, 2015-22 (MMt)



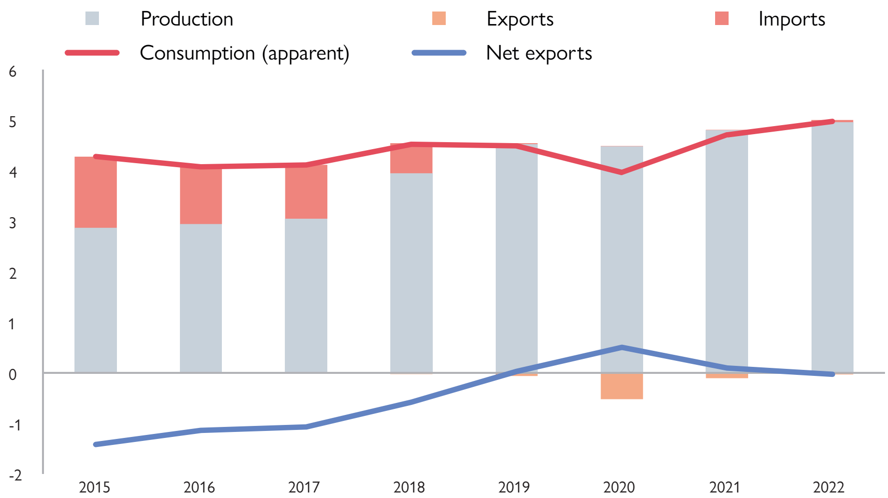
Source: S&P Global Commodity Insights.

role as a Central Asian transit hub. Western sanctions have largely deprived Russia of its traditional role as a transit corridor and hub for flights between Europe and Asia, and Kazakhstan aims to fill this role, but faces competition from other Central Asian states and Turkey. One of the factors international airlines look at in setting up their routes is the availability of Jet A-1—the standard jet fuel in most of the world. TS-1, the most common jet fuel grade currently used in Kazakhstan (and within the former Soviet Union generally), is approved by the majority of aircraft manufacturers, but is slightly more volatile than Jet A-1 due to its lower flash point.[51] A superior grade of jet fuel, the premium RT product, has been manufactured since 2018 by Kazakhstan's Pavlodar refinery, which does not produce the TS-1 grade.

In our base-case outlook, kerosene production grows by 79% over 2023-50 to reach 1.2 MMt/y. Domestic supply is expected to meet domestic demand again by the late 2020s, but Kazakhstan will likely shift back to being a slight net importer of kerosene, l:argely from Russia, starting in the 2030s. But imports are expected to remain modest. Kazakh refinery expansion and upgrades, along with domestic reforms of the jet fuel market, will be instrumental in minimizing dependence on imports and the security risk that entails during the outlook period

- ***The Shymkent refinery is expected to provide the biggest increase in jet fuel output following its planned expansion and further modernization.*** Shymkent will nearly triple production of jet fuel, to around 1 MMt/y by 2030, according to KMG's ambitious expansion plan. If so, then domestic refiners will be able to completely cover all of Kazakhstan's aviation needs.
- ***Greater reliance on market forces via exchange trading would help eliminate chronic product shortages.*** Key distributors, such as KMG and Petrosun, deliver jet kero to consumption points in line with official plans, but airports and

Figure 5.17 Kazakhstan's gasoline balance, 2015-22 (MMt)



Source: S&P Global Commodity Insights.

airlines repeatedly complain about fuel shortages and delays that appear to result largely from the current centralized allocation system and weak development of exchange trading. Only a small share of jet fuel is traded on exchanges (around 10% of the total) and plays no role in domestic price formation; exchange prices tend to be below average wholesale prices, which are in turn typically lower than import prices.[52]

5.5.5.3 Gasoline

Gasoline is the second largest refined product by output and consumption in Kazakhstan. Shymkent is Kazakhstan's largest producer of gasoline. Each refinery dominates supply in a different region of the country. Petrosun and KMG together delivered over 80% of AI-92 and most AI-95 gasoline to the domestic market at last report; relatively little is marketed through commodity exchanges (the official target for commodity exchange sales of gasoline was only 10% of the total earlier this year, though the share of gasoline sold on exchanges is supposed to rise to 20% by 2025).

Gasoline production rose by 3.1% in 2022 to 4.97 MMt—nearly equivalent to domestic demand, which increased by 5.7% to 4.99 MMt. The rebound in domestic consumption squeezed exports, which declined by 76% to 20,000 tons, while imports rose several-fold to 43,000 tons—making Kazakhstan a small net importer of gasoline again in 2022 for the first time since 2018 (see Figure 5.17 Kazakhstan's gasoline balance, 2015-22). During the first six months of 2023, production and consumption of motor gasoline both rose by around 5% to 2.6 MMt.

In our base case, domestic gasoline production expands by 50%, to 7.5 MMt in 2050. Apparent demand rises by 23.0%, to 6.1 MMt. As a result, export volumes are expected to grow several-fold; net exports reach 1.3 MMt in 2050. Longer term, higher private car ownership (stemming from higher personal incomes and GDP growth) drives overall gasoline demand. There is only limited development through 2050 of alternatives to gasoline-fired vehicles (such as electric cars, CNG/LNG, etc.), but one key factor limiting the upside to gasoline demand is increasing fuel efficiencies in engines.

5.5.5.4 Mazut

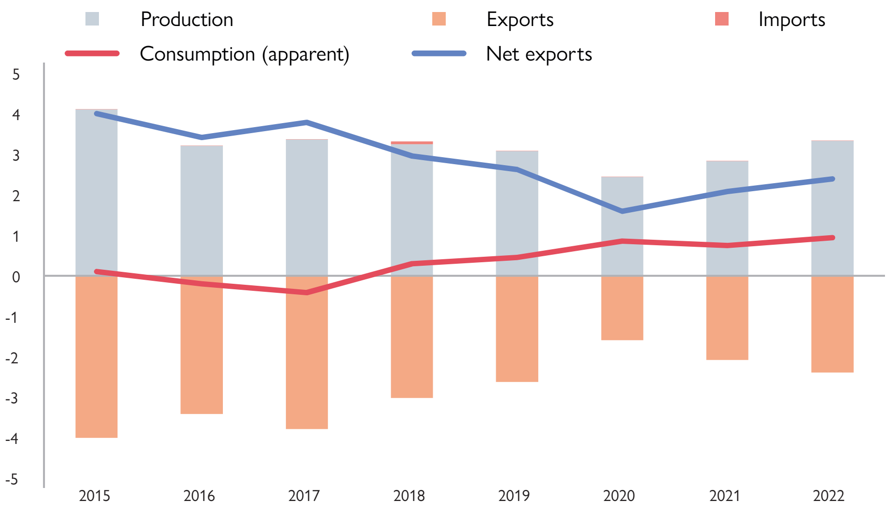
Mazut is a relatively low value heavy product that has traditionally been in surplus domestically and therefore exported in large volumes. Domestically, mazut is primarily consumed in the power/heating sector and agriculture, and domestic prices are regulated for socially important consumers. Consumption is largest in north-central Kazakhstan—a region that has a high concentration of electric power, heating, and industrial enterprises and that has traditionally lacked piped gas (so mazut has served as a back-up or primary fuel). With respect to exports, mazut is typically used as an intermediary feedstock in more sophisticated refineries (often in Europe) as well as a bunker fuel in ships.

Mazut output and exports both contracted starting in 2018 as a result of refinery modernization, but production remains significant; in 2022, higher refinery runs drove output up by 18% to 3.3 MMt (the highest level since 2017). So although apparent demand was also up, to 0.9 MMt (the most since 2010), exports rose to 2.4 MMt (see Figure 5.18 Kazakhstan's mazut balance, 2015-22). It seems that given refinery configurations, refineries may have been compelled to produce more surplus mazut as a byproduct as they ramped up manufacture of the lighter products in higher demand. During the first six months of 2023 the mazut production and consumption trends reversed, as Kazakhstan relied more on imports of selected light products (diesel and kerosene) to meet surging domestic demand, reducing the need to manufacture heavy byproducts; output of mazut fell by 5.5% to 1.6 MMt in January-June 2023 and domestic demand dropped 55.1% to 271,000 tons; even so, exports rose by 23.2% to 1.3 MMt.

51 The TS-1 jet fuel grade has a minimum flash point of 28°C versus 38°C for Jet A-1.

52 Kazakhstan's centralized allocation process for distribution of jet kerosene defies global practices; most airlines or airports worldwide acquire fuel directly from the market under long-term contracts, allowing airlines to reduce costs with economies of scale. The existing system in Kazakhstan forces airlines with higher demand to purchase additional fuel on short notice, at relatively higher prices. A more competitive mechanism could help smooth supply-demand imbalances.

Figure 5.18 Kazakhstan's mazut balance, 2015-22 (MMt)



Source: S&P Global Commodity Insights.

Longer term, mazut output is expected to contract by 73.2% to 0.9 MMt/y by 2050. Further refinery modernization and debottlenecking is expected to raise the share of light products in overall output, reducing the share of heavy products. But domestic demand for mazut is expected to decline by only 4% during the outlook period, holding at about 1 MMt, so Kazakh exports of mazut fall quite steeply. Nonetheless, Kazakh refineries are expected to still have a significant surplus of mazut that will need to be exported during the outlook period, but net exports of mazut drop by 79% to 0.5 MMt in 2050.

5.6 High-Level Takeaways

S&P Global draws the following key conclusions from analysis presented above:

► ***Upstream: Recent improvements to the upstream regulatory and fiscal regimes must be followed up with more far-reaching reforms if Kazakhstan is to compete effectively for limited available global investment capital.*** Important steps taken by Kazakhstan in recent years to facilitate greater upstream spending and development include the online auctioning procedure for E&P blocks starting in 2020 and approval of IMC terms for designated complex projects starting in 2023. But both of these initiatives are falling short of their goals of attracting large-scale new investment; incentives on offer do not compare well with those available elsewhere for global companies. Additional reforms currently on the government's drawing board stop short of addressing many of the above-ground risk issues that are limiting new upstream investment, but do include a number of promising initiatives that should be implemented in the near term—including a Subsoil Code amendment that would give producers more leeway to diverge from originally-planned project indicators without so many additional administrative procedures, and extension of the scope of the Alternative Subsoil Use Tax to include mature fields.

► ***Midstream: Kazakhstan's trans-Caspian oil export diversification push promises to reduce dependence on Russian routes and lower overall midstream risk, but official trans-Caspian shipment targets will probably need to be scaled back given infrastructure constraints and high transportation costs.*** Key potential advantages of the trans-Caspian route include ample spare capacity in the Baku-Tbilisi-Ceyhan pipeline and access to broader global markets. In contrast, the chief other export route for Kazakhstan bypassing Russian territory—the Kazakhstan-China Pipeline—cannot access multiple world markets. But the government's aspirational target of a massive (several-fold) increase in trans-Caspian oil export volumes seems overly ambitious. Midstream players would likely be reluctant to commit to the major additional expenditures that would be required, such as fleet and terminal expansion and other infrastructure—especially in the absence of larger throughput commitments by crude shippers. It also remains unclear how much diversification is actually needed to reduce the overall export risk to a tolerable level.

► ***Downstream: Price liberalization is required along with refinery expansion to ensure that the growing domestic oil market is well supplied.*** One of the most critical drivers of domestic price liberalization, alongside EAEU integration, is the expected tightening supply of crude oil after 2025. With the decline of legacy KMG production, refiners will need to access alternative sources of supply. Given the right price signals, some of the necessary supplies can come from the IOCs' production streams and the smaller independent Kazakh oil producers. If domestic prices are kept artificially low, Kazakh authorities will likely need to continue resorting to an imperfect array of administrative measures to direct sufficient crude and products to the domestic market, domestic demand will be higher than otherwise, and refinery expansion and investment will need to be on a larger scale. There are other energy security considerations that factor in, including the need to stem "leakage" of low-priced Kazakh motor fuels to consumers in neighboring states.

CHAPTER 6

NATURAL GAS SECTOR AND DEVELOPMENTS IN KAZAKHSTAN'S OVERALL GASIFICATION STRATEGY

6. NATURAL GAS SECTOR AND DEVELOPMENTS IN KAZAKHSTAN'S OVERALL GASIFICATION STRATEGY

6.1 Key Points

► A major national goal is to expand the role of gas in the economy and to change the underlying economics of the sector. To accomplish this, on 31 December 2021, the Government of Kazakhstan approved the Comprehensive Plan for Kazakhstan's Gas Industry Development for 2022–2026 and also established a new national champion for gas, JSC National Company QazaqGaz. QazaqGaz operates as a fully vertically integrated company with activities spanning the entire gas value chain, including exploration, production, transportation, and distribution.

► One aspect of this program is to expand the country's existing gas resource base by making investment in upstream gas development attractive, and in so doing, expanding the total amount of gas being produced. Seven prospective new gas-oil and gas-condensate fields are planned to be put onstream over the next 5–7 years to provide incremental raw gas production of up to 4.2 Bcm/y by 2030.

► In order to secure the substantial incremental volumes of gas called for in the Comprehensive Plan for Kazakhstan's Gas Industry Development for 2022-2026, policymakers in government and in the national energy companies KazMunayGas and QazaqGaz focused on two policy approaches: (a) lowering the costs of exploration and production from new fields and improving the legal environment surrounding their licensing (Improved Model Contract); and (b) increasing the prices that producers will receive for gas from these new fields within a new administrative structure under the newly reorganized national gas company QazaqGaz.

►Another key goal in expanding gas supply is to make more commercial gas available by expanding gas processing capacity. But new capacity is very expensive as it has to process high-sulfur associated gas. By 2030, Kazakhstan plans to add 10 Bcm/y of new processing capacity.

► A major new direction began in Kazakhstan's end-user pricing policy in 2022, with the introduction of more differentiated pricing by establishing three new consumer categories – large commercial consumers, crypto miners, and a socially vulnerable group. The first two consumer groups (large commercial consumers, crypto miners) are expected to pay higher prices to cover higher costs of production and imports of "new" gas. The socially protected group receives a significantly lower price.

►Additionally, at the end of 2022, the government approved amendments to the Law on Gas and Gas Supply, whereby wholesale ceiling prices for natural gas are now set for a five-year period to provide longer-term guarantees for gas market players (previously ceiling prices were set annually). Wholesale ceiling prices are set regionally as well as for entities that use natural gas to produce CNG or LNG for further sale to end-consumers. The Order of the Minister of Energy of the Republic of Kazakhstan No. 246 dated 30 June 2023 approved ceiling wholesale prices in Kazakhstan's domestic market for the commercial gas intended for subsequent sale to large commercial consumers, digital miners, or producers of electricity for digital mining activities for the period from 1 July 2023 to 30 June 2024. Provisions are made for the possibility of an annual increase in the range of 20-75% in the following years in order to move gas prices to economic levels.

► In 2022, Kazakhstan's gross gas production was reported as 53.2 Bcm, slightly lower than in 2021. Commercial gas production (excluding reinjected volumes) amounted to 36.0 Bcm in 2022. Longer term, commercial gas supply is being pressed by strong domestic demand, especially as gas displaces coal in the power sector. This is because commercial gas production is likely to be constrained due to sustained reinjection needs, which will remain an important, economically effective gas utilization option for upstream operators. Commercial output will likely peak in the mid-2030s, at around 42 Bcm/y, reflecting the construction schedules of planned new gas processing capacity.

► Since independence, Kazakhstan has succeeded in creating a unified domestic gas transportation and distribution system. Yet, the gas transportation infrastructure is constrained by a high degree of deterioration and resultant low throughput capacity. QazaqGaz subsidiary Intergas Central Asia intends to modernize the gas transmission system and has developed a plan to 2030, designed to reduce the level of asset depreciation substantially.

► The further gasification of Kazakhstan's cities and settlements remains a key strategic priority of policymakers. The country reached its previously set 2030 gasification goal of 56% nine years ahead of schedule, in 2021. An updated goal of 65% of the population to have access to pipeline gas by 2030 was recently set. The largest presently unserved regions are located in north-central and eastern Kazakhstan. The government is presently considering a variety of options to supply these regions, either with domestic or imported gas.

► In 2022, end-of-pipe gas consumption reached 19.3 Bcm, a 4% increase over 2021. Gasification was an important driver behind such robust growth in end-user demand. By 2050, S&P Global envisions national gas consumption (end-of-pipe deliveries) will reach around 33.2 Bcm. Gas use in the economy is expected to largely backfill for declining coal consumption rather than represent net additions to primary energy consumption.

► Exports to China plummeted in 2022 by 21%, mainly due to lack of commercial gas supply. Although several factors created a perfect storm for gas tightness in Kazakhstan during the winter of 2022-23, the decline is symptomatic of a larger problem. While Kazakhstan is still a net gas exporter, it is facing the threat of a natural gas shortage: its gasification program is driving up consumption while commercial gas production remains essentially flat. S&P Global expects that through domestic gas market reforms (price increases and improved E&P terms) and other policy changes (construction of GPZs and additional imports) Kazakhstan's gas supply-demand balance will shift, resulting in a rebound in Kazakhstan's gas exports in the late 2020s. We expect that Kazakhstan will remain a net exporter until about 2040, but will continue to effectively utilize gas imports from the north and the south.

► Long-held plans to establish a major gas-based petrochemical industry in western Kazakhstan appear to now be bearing fruit. In November 2022, the first phase of the Atyrau integrated gas-chemical complex was launched with a new 0.5 MMt/y polypropylene plant, to be followed by the second phase's 1.25 MMt/y polyethylene plant (expected by 2028). Kazakhstan has an ample supply of low-cost NGLs such as ethane, propane, and butane that can be used as feedstocks for NGL-based petrochemical development. A recent program for petrochemical development envisions about $15 billion in capital expenditures to build several regional clusters, adding five major facilities by 2025. Kazakhstan has access to substantial gas-type feedstocks that can be utilized for petrochemical production. However, given the lack of commercial gas supply, S&P Global does not anticipate a prolific expansion in gas-based (methane) petrochemical development in Kazakhstan.

► Since 2015, Kazakhstan's LPG consumption has been expanding rapidly, with demand increasing on average by 16% annually through 2021 and by 21% in 2022, driven mainly by rapid growth in demand in (vehicle) transportation. In S&P Global's base-case outlook, Kazakhstan's LPG production almost doubles, reaching almost 5.7 MMt by 2035 but then slowly declines thereafter to about 5.1 MMt in 2050. The petrochemical sector will be the largest incremental source of domestic demand over the outlook period. Liberalization of the LPG market has been postponed to 2025.

6.2 Introduction

Since 2021, Kazakhstan's gas sector has been a key focus for a broader transformation and general reforms. In many ways these changes are welcome and long overdue. The recent shift was driven to the fore by a tightening gas balance for the country and prospects of a looming "shortage" of gas for consumers, stemming from the previous one-sided policy of wider adoption of natural gas ("gasification"), particularly by households, without other supportive changes. A related central problem was that the basic business of delivering gas to Kazakh consumers was unprofitable for the national gas company.

Historically, Kazakhstan has not been a significant consumer of natural gas, especially when compared to its regional peers. The abundance of low-cost domestically produced coal relegated gas use in the economy to a distant second place in the national energy balance. Coal still provides the majority of the country's primary energy supply, although the share of gas has been growing. The adoption of a broad gasification strategy in late 2014 and adoption of the Paris Agreement's carbon reduction goals in 2016 were preeminent underlying drivers in this strategy to increase gas consumption in the country. Since 2015, end-of-pipe gas consumption has increased at an annual average rate of 7%; unfortunately, commercial gas supply has increased at a more modest 3.5% per year on average. This resulting squeeze on gas supply forced a reduction in important gas exports to China, compelling the government to review its basic approach to the gas sector.

Kazakhstan relies mainly on associated gas production and its subsequent processing (into commercial gas) to supply the bulk of its domestic gas needs. Essentially a by-product of oil production, associated gas output cannot be readily scaled to changes in demand; its availability is largely shaped by liquids production decisions. Reinjection needs and limited gas processing capacity, particularly for raw high-sulfur associated gas, also restrict commercial gas availability. Historically, Kazakhstan was able to effectively leverage its associated gas resource, procuring it for the domestic market at very low prices. This was often below costs for upstream producers, so gas supply was effectively being cross-subsidized through oil exports.

However, rising gas consumption and ambitious plans to increase gas use in the residential as well as petrochemical, industrial, and power sectors, now underscore the need to secure additional sources of commercial gas through a different approach. To that end, the government established a new vertically integrated national gas company, responsible for the full range of activities from gas exploration and production to transportation, exports, and processing of gas, spinning it out of the national oil company. Armed with this new mandate, QazaqGaz quickly has championed the need for significant changes in overall gas market policy and regulations. These changes focused on three key areas:

- Increasing the availability of commercial gas supplies via two means – new gas processing capacity and new resource development.
- Increasing gas sector investor attractiveness by offering incentives to develop "new" gas. These incentives include new legislation on exploration and development of gas fields, and offering higher prices for produced gas.
- Broader acceptance of the need to raise end-user prices for gas, with more differentiation of consumer categories (e.g., large industrial users and crypto miners) and securing general agreement that average prices for most consumer categories are set to increase going forward "on a measured basis."

A number of gas-related priorities are being pursued by Kazakhstan. These include expanding overall gas use in the economy, including greater gasification of the residential sector, expanding gas-based petrochemical production, and expanding the use of gas in other industries, particularly in electric power. The latter is especially critical given recent power grid reliability issues coupled with increased renewables penetration, driving the need for more flexible generation capacity. Other recognized priorities are to continue gas exports to China and to effectively use imported gas in the north and south to manage overall system needs. The challenge for Kazakhstan is that these "new" sources of gas will be more expensive no matter where they come from, with locally produced gas likely being more expensive (but also offering more energy security), while imported gas (even if it is less expensive than "new" local gas) has an energy security risk attached to it. This chapter describes in more detail the most recent developments in Kazakhstan's gas industry and offers an outlook for the sector's development.

6.3 Reserves and Exploration

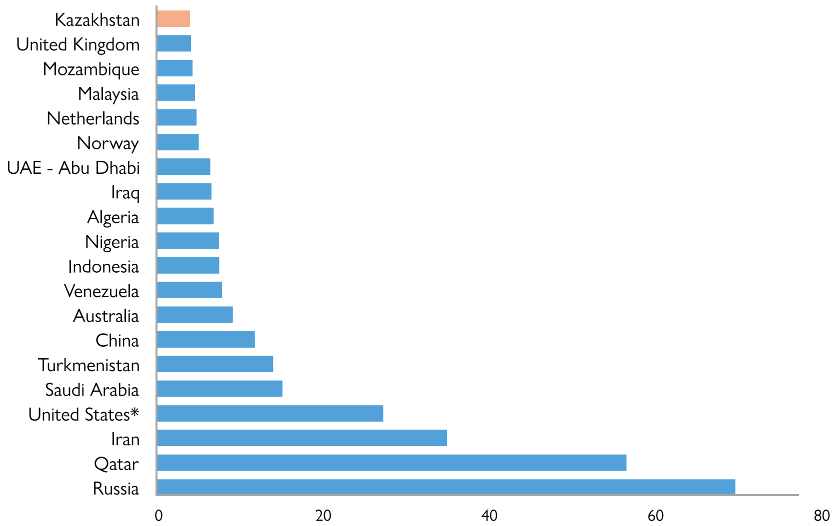
Kazakhstan's ample gas reserves place the country in the top 20 gas resource holders globally (see Figure 6.1 Top 20 countries by recoverable gas reserves (proven+probable)).[1] As of 2023, Kazakhstan's gas reserve base was reported at 3.79 trillion cubic meters (Tcm).[2] Currently, S&P Global estimates Kazakhstan's 2P gas reserves at 138 trillion cubic feet (4.0 Tcm), which are predominantly concentrated in the Precaspian Basin in the northern and western portions of the country.[3] The Precaspian Basin comprises 89% of Kazakhstan's gas reserves and encompasses the three supergiant oil and gas fields—Karachaganak, Tengiz, and Kashagan—the crown jewels in Kazakhstan's oil and gas industry. Two other important basins in the western part of the country—Mangyshlak-Central Caspian and North Ustyurt—possess more than 300 Bcm of recoverable reserves and have favorable exploration potential (see Table 6.1 Kazakhstan's estimated 2P gas reserves by basin in 2023). Slightly more than half of the reserves consist of associated gas (held in solution with liquid hydrocarbons in the reservoir) and the remainder is "free" gas. Almost 85% of gas reserves are found in the ten largest fields (including the "Big 3" mentioned above as well as Zhanazhol, Imashevskoye, Korolevskoye, Uzen, and Zhetybay), albeit at considerable depth (up to 5 km) and often with high sulfur content, both of which complicate field development and production and contribute to relatively high production and processing costs.

In terms of operatorship, the three biggest holders of gas reserves are NCOC, KPO, and TCO (see Figure 6.2 Kazakhstan's 2P gas reserves in 2023 by operator). The only other significant reserve holder—CNPC-AktobeMunayGas—has its most important gas reserves in the Zhanazhol field, which accounts for about 3.4% of Kazakhstan's total.

Kazakhstan's simpler gas fields (those with shallower depths or without sulfur) contain only rather small gas reserves, and tend to be of only local importance for supply to nearby customers. However, these types of fields have been developed, mostly in areas other than western Kazakhstan, such as in Kyzylorda, Zhambyl, Turkestan, and East Kazakhstan oblasts.

Kazakhstan is looking for ways to expand the country's existing gas resource base through developing new upstream acreage (see Section 6.3.1). The country has enacted new legislation, including the Improved Model Contract (IMC), to make investment in Kazakhstan's upstream more attractive to investors (see below).

Figure 6.1 Top 20 countries by recoverable gas reserves (proven+probable) (Tcm)



Notes: *Includes conventional gas reserves (only US Gulf of Mexico & Alaska). Canada not included due to mined oil sands.
Source: S&P Global Commodity Insights.

1 By international definitions for just "proven" ("1P") reserves, Kazakhstan is considered to possess 2.3 Tcm as of the end of 2020 (essentially unchanged since 2016), or 1.2% of the global total *(BP Statistical Review of World Energy,* July 2023). By this measure Kazakhstan ranks fourth among CIS countries (after Russia, Turkmenistan, and Azerbaijan) and 16th in the world.

2 The reserves are reported according to the domestic definition (in categories A+B+C1+C2), which roughly correspond to the international equivalent of proven + probable (2P) reserves. Slightly more than half (about 57%) is associated gas (held in solution with liquid hydrocarbons in the reservoir) and the remainder is "free" gas (~1.6 Tcm). The state balance for 2022 identifies gas reserves in 287 fields.

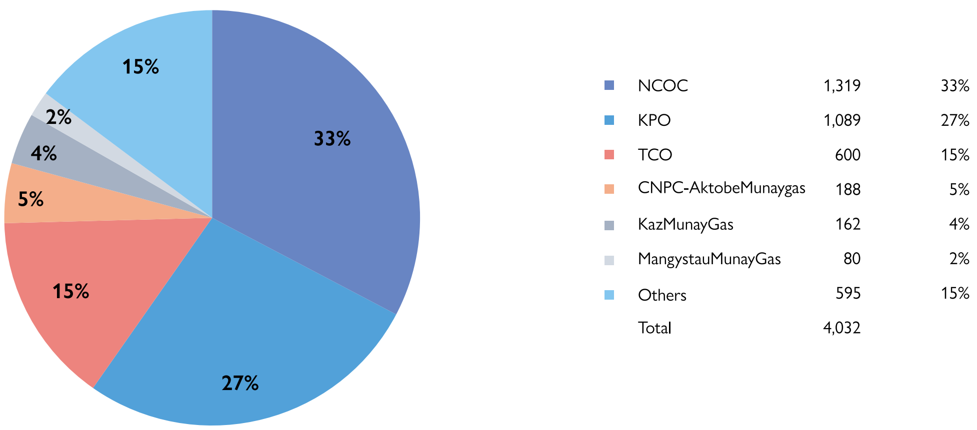
3 This represents a slight reduction in reserves estimates compared to that given in *The National Energy Report 2021* (at 152 trillion cubic feet [4.4 Tcm]), mainly due to the reevaluation of the Caspian region and the reserves for several larger fields, including Kashagan, Tengiz, Rostoshinskoye, and Rozhkovskoye.

Table 6.1 Kazakhstan's estimated 2P gas reserves by basin in 2023

Basin	Gas recoverable 2P reserves (MMscf)	Gas recoverable 2P reserves (MMcm)
Precaspian Basin	122,819,594	3,587,021
Mangyshlak-Central Caspian	7,977,885	232,999
North Ustyurt Basin	3,543,254	103,483
Turgay Basin	2,094,202	61,162
Volga-Urals Basin	503,970	14,719
Chu-Sarysu Basin	935,758	27,329
Zaysan Basin	165,290	4,827
North Caucasus Platform	25,000	730
Total	138,064,953	4,032,271

Notes: Data as of 25 July 2023; 2P = proven+probable.
Source: S&P Global.

Figure 6.2 Kazakhstan's 2P gas reserves in 2023 by operator (Bcm)



Source: S&P Global Commodity Insights.

6.3.1 Plans to increase the gas reserve base

One of the key goals of the Comprehensive Plan for Kazakhstan's Gas Industry Development for 2022–2026 is to expand the country's gas availability through developing new upstream acreage. Although the largest gas reserves are contained within the "Big 3" projects, where costly gas processing is required to produce commercial gas, the Plan also calls for QazaqGaz and KMG to develop a number of prospective gas fields over the next 5-7 years. Overall, the plan envisions that seven new gas-oil and gas-condensate fields will be put onstream, including Urikhtau, Prorva West, Pridorozhnoye, Anabay, Rozhkovskoye, Ansagan, and the Teplovsko-Tokarevskoye Group (see Figure 6.3 Kazakhstan's new sources of gas: Planned upstream development by KMG and QazaqGaz). These upstream projects are expected to provide incremental raw gas production of up to 4.2 Bcm/y by 2030 (see Table 6.2 Kazakhstan's prospective gas fields and expected "new" gas output by 2030 and Figure 6.4 New planned projects to increase gas production by 2030).

QazaqGaz

QazaqGaz announced that it plans to put three new fields into operation within the next five years. All three fields are located in the Chu-Sarysu Basin in south-central Kazakhstan:

- The ***Anabay field*** in Zhambyl Oblast is set to come online in Q3 2023.[4] The Anabay field was first discovered in 1979; its reserves are estimated at 3.1 Bcm.
- The ***Barkhannaya/Sultankuduk field***, also in Zhambyl Oblast, is planned to be launched in 2026.[5] Initially discovered in 1982, the field's reserves are estimated at 0.5 Bcm.

4 Field development plans include drilling four wells (No. 17, 18, 19, 20) with planned depth of 3,500 m. Initial production is expected at 16 MMcm/y, with a later expansion to 40 MMcm/y, according to QazaqGaz.

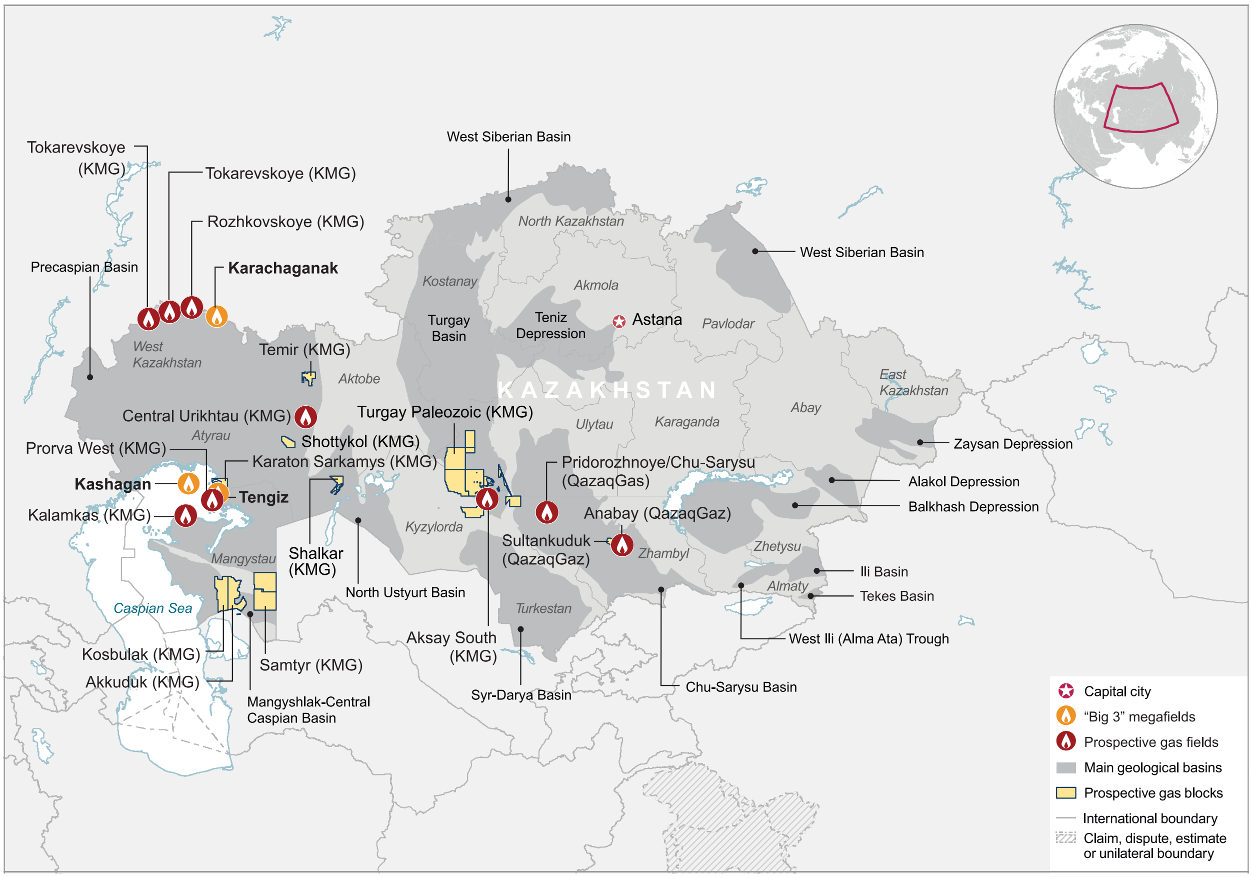
5 QazaqGaz plans to drill three wells (B-5, B-6, K-1) at Barkhannaya, with expected production of 48 MMcm/y.

- The third field, ***Pridorozhnoye*** in Turkestan Oblast, is currently in the design stage, with production slated for 2027.[6] The Pridorozhnoye field's reserves are estimated at around 16 Bcm; the field was discovered in 1973.

The relatively modest reserves of these three fields as well as their remoteness from existing gas infrastructure were the key reasons why they were not developed previously. To further grow its gas resource base, QazaqGaz is working to obtain licenses for exploration of new areas, in the Mangyshlak and Caspian and Aral areas, as well in Aktobe Oblast. The company reportedly already has identified several promising areas and plans to conduct seismic surveys at some point in the future (see Table 6.3 QazaqGaz identified promising exploration areas). In August 2022, QazaqGaz and Azerbaijan's SOCAR signed a Memorandum of Understanding for the development of new gas and gas condensate fields.[7] In early 2023, QazaqGaz signed similar memoranda of cooperation with Dragon Oil and Petromal Sole Proprietorship LLC for the upstream development in Kazakhstan. In May 2023, during the first Central Asia-China Summit, QazaqGaz also signed an agreement with China's CNPC on cooperation in gas supply and in exploration.

In 2022, QazaqGaz created a separate subdivision, E&P QazaqGaz, for the exploration and production of natural gas. All new subsoil use projects will be consolidated under the new subsidiary. QazaqGaz plans to obtain 10 more subsoil contracts for gas exploration.

Figure 6.3 Kazakhstan's new sources of gas: Planned upstream development by KMG and QazaqGaz



Source: S&P Global Commodity Insights upstream E&P/basins content (EDIN): 2009730.

6 In late 2024, QazaqGaz plans to begin construction of a gas processing unit at the Pridorozhnoye field. Gas output is expected at 107 (or 142) MMcm/y, rising to 300 MMcm/y at a later stage.

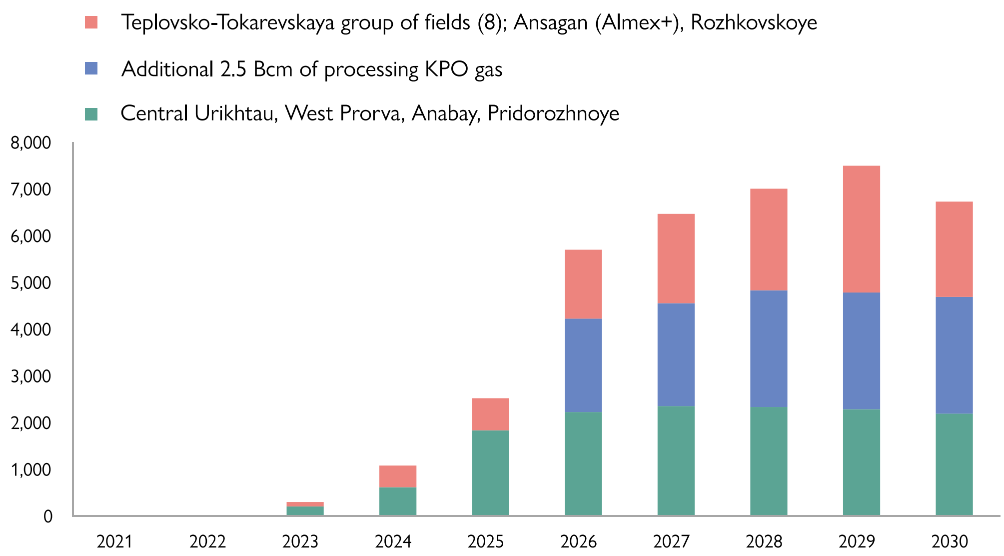
7 In addition to gas exploration, the Memorandum also covers gas processing development, petrochemical development, and the modernization of the gas transportation industry.

Table 6.2 Kazakhstan's prospective gas fields and expected "new" gas output by 2030

New gas fields	Expected gas output (MMcm/y)	Production start	Company
Urikhtau Central	900	2026	KMG
Prorva West	600	2027	KMG
Pridorozhnoye	142	2027	QazaqGaz
Anabay	16	2023	QazaqGaz
Rozhkovskoye	980	2023	KMG
Ansagan	462	n/a	KMG
Barkhannaya	48	n/a	QazaqGaz
Aksay Yuzhny	100	2023	KMG
Kalamkas	350	2027	KMG
Turgay Paloezoic	100	2028	KMG
Karaton Subsalt	930	2027	KMG
Total	**4,628**		

Source: S&P Global.

Figure 6.4 New planned projects to increase gas production by 2030 (MMcm)



Source: Comprehensive Plan for Kazakhstan's Gas Industry Development for 2022–2026, S&P Global Commodity Insights.

Table 6.3 QazaqGaz identified promising exploration areas

Basin	Basin resources (Tcm)	Blocks
Precaspian	51	Zhalibek, Temir, Shottykol
Mangyshlak	3.2	Akkuduk/Kendala, Samtyr
Karaganda coal basin	0.8	To be determined

Source: Working group analysis, QazaqGaz, KIOB, expert interviews.

KMG

KMG also has plans for the development of new fields that will yield "new" gas output, announcing a roadmap for increasing the volume of commercial gas in from KMG's assets (see Figure 6.5 KMG's plan to increase gas output by asset type). The plan calls for increasing KMG's gas output from 2.2 Bcm in 2022 to 6.7 Bcm in 2030, from a combination of current assets and the development of new ones. This focuses on the development of the Central Urikhtau and Prorva West onshore fields as particularly promising near-term targets (they have already been discovered), but includes other fields and blocks as well.[8]

- In May 2023, Kazgermunay, a joint venture between KMG and PetroKazakhstan Inc., launched the ***Aksai Yuzhny*** gas condensate field in Kyzylorda Oblast. With estimated reserves of ~2 Bcm, gas production is expected to be about 100 MMcm/y.
- By the end of 2023, KMG plans to put online the ***Rozhkovskoye*** gas condensate field in West Kazakhstan Oblast.[9] KMG owns 50% of the asset, with the remaining shares belonging to MOL (FED) Kazakhstan (27.5%) and First International Oil Corporation (FIOC) (22.5%). Recoverable condensate reserves are estimated at 12.5 MMt and recoverable gas reserves at 26.8 Bcm. KMG expects gas production of up to 1 Bcm/y from the field to be supplied to Zhaikmunai's gas processing plant (Nostrum Oil & Gas Plc) for processing and subsequent delivery to the domestic market.
- Post-2024, KMG plans to develop the ***Central Urikhtau*** gas field, which is a gas play within the larger Urikhtau license area in Aktobe Oblast. KMG estimates potential gas production of 1 Bcm/y and 209,000 tons of condensate per year from the field.
- Post-2027, KMG wants to increase gas output from the ***Prorva West*** field in Atyrau Oblast through the expansion of gas treatment capacity and new production from the field's gas-bearing horizons.[10] S&P Global estimates recoverable 2P gas reserves at ~38 Bcm while KMG's subsidiary EmbaMunayGas reports 8.6 Bcm of ready-to-be developed gas reserves.
- KMG and the Ministry of Energy indicated several other sources of additional onshore gas production, including: (1) expansion of production at the (onshore) ***Kalamkas*** field; (2) new gas production at the ***Ansagan*** field[11] (Atyrau Oblast); and (3) exploration and production at the ***Teplovsko-Tokarevskoye group*** of fields.[12] Geological information remains somewhat limited, but in general they present such operational challenges as small field size, unfavorable gas composition, or low flow rates.[13]

In terms of other onshore exploration, KMG is searching for hydrocarbons in ***Turgay Paleozoic*** acreage in Kyzylorda Oblast (project timeframe 2021-27). The company plans to begin drilling a 5,500 m exploration well (PZ-1) in 2023, with further development contingent on drilling results. KMG estimates recoverable resources at 23.1 MMt of oil with required capex of 581 billion tenge ($1.3 billion) for project development.

In June 2023, KMG and the Ministry of Energy of Kazakhstan signed a contract for hydrocarbon exploration and production in the Karaton Podsolevoy (Karaton Presalt, also known as ***Karaton-Sarykamys***) onshore contract area, located in the Atyrau and Mangystau oblasts. The contract area is located near TCO's Tengiz and Korolevskoye fields, as well as a group of Embamunaygaz fields (KMG). Several post-salt shallow wells have been drilled and minor oil discoveries made in the area, but the new project will target the unexplored pre-salt plays. In June 2022, KMG and Russia's Tatneft entered into an agreement of intent on joint implementation of the Karaton-Sarykamys project. Tatneft is expected to provide carry-finance for the project. According to the Kazakh government's draft resolution "On Approval of an Integrated Plan for Development of Major Oil and Gas and Petrochemical Projects in 2023-2027" from May 2023, financing for the Karaton-Sarykamys project could total $2.4 billion. Preparatory work to drill a deep exploration well is underway, with drilling scheduled to begin in 2024. But actual development and production are contingent on the discovery of hydrocarbons.

In terms of offshore exploration, in February 2023 KMG and Kazakhstan's Ministry of Energy signed a contract, governed by the new IMC framework, for the development of the offshore ***Kalamkas-More, Khazar, and Auezov fields*** as a single, integrated project. KMG has moved forward with its plans to co-develop the project with Russia's Lukoil.[14] This project was previously rejected by international majors holding licenses to the fields due to challenging upstream economics. The signing

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8 After QazaqGaz was designated a national operator for gas in November 2021, the government of Kazakhstan updated the rules for delineation of activities of national companies in the field of subsoil use. KMG is responsible for exploration and production of oil and gas resources at oil fields. QazaqGaz is responsible for exploration and production of gas resources at gas and gas condensate fields. The delimitation of activities between KMG and QazaqGaz is through mutual agreement. It appears that the gas fields currently on the books with KMG will remain so (QazaqGaz attempted to get these gas assets transferred over, but this failed to materialize). https://adilet.zan.kz/rus/docs/P2100000854.

9 The Rozhkovskoye gas condensate field was discovered in 2008 in West Kazakhstan Oblast (developed by Ural Oil and Gas). The contract for the production of gas and condensate at the field No. 4130-UVS-ME was signed in 2015.

10 Originally discovered in 1963, the Prorva West field was first put in production in 1977. KMG acquired additional seismic exploration data in 2007.

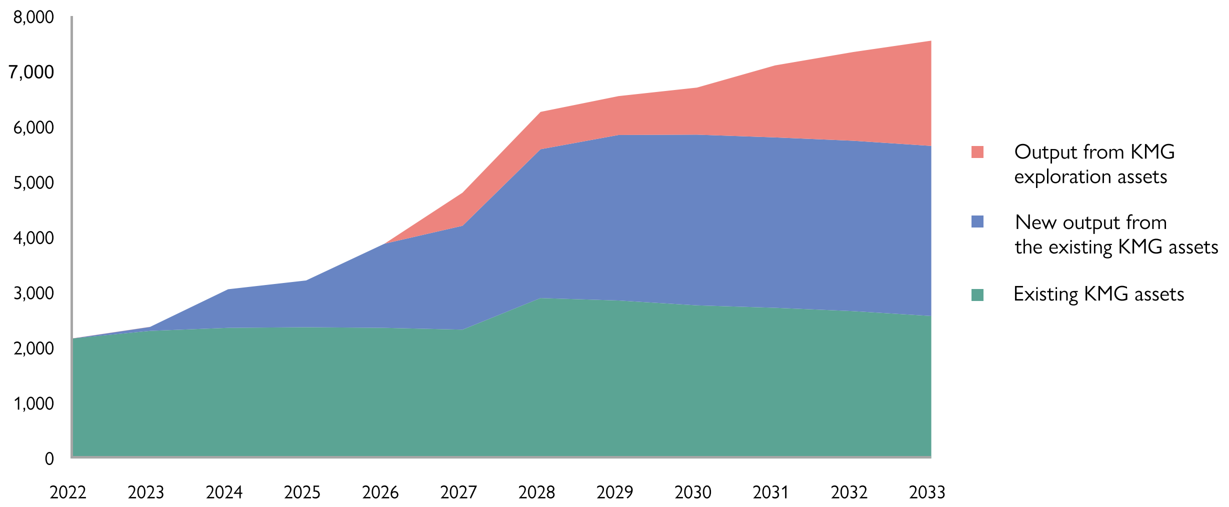
11 Initially discovered by TCO in 2006, Ansagan was acquired by Almex Plus LLP in early 2014. Ansagan was originally interpreted as an oil find, but in January 2017, the Ministry of Energy announced a discovery of "light oil and gas" pools in a Devonian reservoir. Although Ansagan is 100% owned by Almex Plus LLP, KMG appears under contract to do the appraisal work.

12 On 17 July 2023, Nostrum Oil & Gas completed the acquisition of an 80% interest in Positive Invest LLP, which holds the subsoil use rights for the Kamensko-Teplovsko-Tokarevskoye area (the "Stepnoy Leopard fields") in the northern part of the Precaspian Basin. Nostrum estimates that the Stepnoy Leopard fields hold between 50 MMboe and 150 MMboe of recoverable hydrocarbons, which are considered contingent resources, with only about 20% estimated to be liquids. The Stepnoy Leopard fields are located approximately 60-120 km west of Nostrum's Chinarevskoye field and within 10 km of its oil and condensate loading terminal at Beles. Nostrum will work with Positive Invest to formulate field development plans for each of the eight fields and submit them to the Ministry of Energy for approval for tieback to Nostrum's existing infrastructure, thereby improving the fields' economic viability. Positive Invest's contract expires in December 2044. First production launch is planned for 2025.

13 Another example is the Shyrak field in the northern Precaspian Basin near Karachaganak. A gas blow-out occurred there over a decade ago, with further activity on hold since then.

14 As of August 2023, KMG announced the completion of the final stage of the process of transferring to Lukoil a 50% stake in Kalamkas-Khazar Operating LLP, created specifically for the development of the Kalamkas-More, Khazar, and Auezov offshore deposits. The company intends to begin developing the project documentation phase by the end of 2023.

Figure 6.5 KMG's plans to increase gas output by asset type (MMcm/y)



Source: KMG, S&P Global Commodity Insights.

bonus for the project amounts to $32 million, with expected capex of at least $6 billion.[15]

NCOC, the international consortium developing the Kashagan field, discovered Kalamkas-More in 2002, located 75 km southwest of the Kashagan field. S&P Global estimates Kalamkas-More 2P reserves at 21.4 MMt (156.5 MMbl) of oil and 6 Bcm of gas. The Khazar field was discovered by the Shell-led Caspi Meruerty Operating Company (CMOC), also known as the Pearls Production Sharing Agreement (PSA), in 2007.[16] It is located about 40 km southwest of Kalamkas-More and was a part of the Zhemchuzhiny (Pearls) discoveries that also included the Auezov and Naryn fields.[17] S&P Global estimates the Khazar field's 2P reserves at 23 MMt (167 MMbl) of oil and 2.7 Bcm of gas.

Both the Kalamkas-More and Khazar fields are part of the North Ustyurt Basin, characterized by relatively shallow reservoir depths (1,500–2,000 m) with no salt layer in the section. This contrasts with the geology of the Kashagan field, located in the Precaspian Basin, with the main reservoir at a depth of 4,200 m. The combined reserves of the Kalamkas-More and Khazar fields were reported at 80 MMt of oil and 9 Bcm of gas.

KMG is conducting geological exploration at the ***Abay***[18] and ***Al-Farabi*** (known formerly as the I-P-2 block) offshore projects. In July 2023, KMG and its partner Lukoil exited the Zhenis block after an unsuccessful exploration well failed to find commercial reserves.[19]

As seen from the extensive list above, both QazaqGaz and KMG have ambitious plans to expand upstream gas exploration and production. A question, though, is whether other investors, particularly international majors, will find the new legislative changes appealing enough to spend their money in Kazakhstan on upstream gas development and work with them on this endeavor.

6.4 Upstream Legal Framework

Kazakhstan's 2017 Subsoil Code stipulates that the state's interests in the upstream natural gas sector are to be represented by the "National Company for Hydrocarbons." The state—via the National Management Holding Group, the joint-stock company National Welfare Fund "Samruk-Kazyna" (NWF SK)—is the majority shareholder in this company. The Law on Gas and Gas Supply from January 2012 designates this company as the "national operator" for the county's single-buyer model of gas procurement, transportation, and distribution.

Prior to the end of 2021, it was a KMG subsidiary, JSC NC KazTransGas (KTG), that satisfied these criteria. In June 2021, President Tokayev emphasized the need for a new gas strategy concept that would transform KTG into a full-fledged vertically integrated national gas company with activities spanning the entire gas value chain. So in November 2021, a 100% ownership stake in KazTransGas JSC was transferred from KMG to Samruk-Kazyna. On 31 December 2021, the Government of Kazakhstan approved the Comprehensive Plan for Kazakhstan's Gas Industry

15 Pending Lukoil's ability to provide the requisite financing, the project is expected to generate about 2,000 new jobs and aims to support Kazakh companies and contractors and leverage Kazakh ports and other facilities.

16 At the time, CMOC shareholders were Shell (40%), Oman Pearls Company (20%), and KMG (40%).

17 Auezov's 2P reserves are estimated at 5 MMt (36.5 MMbl) of oil and 0.3 Bcm of gas.

18 In July 2019, Italy's Eni and KMG signed a hydrocarbons exploration and production contract for the Abay block in the Kazakh sector of the Caspian Sea. The block's reserves are estimated at 760 MMtoe (~5.5 billion boe). The agreement between KMG and Eni provides for the drilling of one exploration well (2,500 m depth) and a 2D seismic survey of 700 linear km, with estimated costs of over 14 billion tenge (about $31 million).

19 KMG and Lukoil signed a contract for exploration and production of hydrocarbons at the Zhenis block in April 2019. The first offshore well was spudded at Zhenis in December 2022. The minimum obligations for the project were to drill one exploration well and to conduct 3D seismic surveys; estimated costs were on the order of $60 million. Lukoil financed 100% of the exploration costs of the Zhenis project. The license has now been returned to the state.

Development for 2022–2026 that reorganized KazTransGas into a new national company JSC National Company QazaqGaz. At the same time, the Kazakh government updated the Decree "On approval of the delimitation of the activities of national companies in the field of subsoil use," whereby QazaqGaz was designated as responsible for exploration and production of natural gas at gas and gas-condensate fields (see text box Role of QazaqGaz as a vertically integrated national company).

ROLE OF QAZAQGAZ AS A VERTICALLY INTEGRATED NATIONAL COMPANY

Under current legislation, QazaqGaz not only remains the monopoly operator of all gas transmission and distribution infrastructure in the country but also has exclusive rights to purchase (associated) gas from producers, sell gas on the domestic market, and export gas. The creation of independent QazaqGaz is part of a "re-branding" effort, signaling a new approach to the company's role, extending beyond its previous chief focus on gas transport to focus more comprehensively on broad development of the overall gas resource in the country. It is intended to improve the overall investment attractiveness of the gas sector, increase geological exploration, improve domestic gas pricing policies, and promote further gasification of the economy (including in transportation and deeper processing in the petrochemical industry). This new approach reflects:

- ► A changed view of natural gas from being only a by-product of liquid hydrocarbons to a valuable resource in its own right
- ► A desire for greater openness to outside investment and international metrics (e.g., international audits, Western metrics of business performance)
- ► A changed pricing policy for gas in the domestic market to stimulate upstream development, and netback pricing for export-oriented industry
- ► Creation of new upstream (E&P) segment, based on a renewed effort to attract development (new Model Contract, special upstream terms for gas) and perhaps also an international dimension (e.g., developing gas in Turkmenistan)
- ► An embrace of imports to augment domestic supply as needed (from Turkmenistan and Russia)
- ► Continued focus on greenhouse gas emissions reductions, especially of methane; this harmonizes with efforts to burnish the company's "green" credentials and increase its attractiveness to investors; these are to be implemented through upgrading/refurbishing pipeline networks and deploying digital and remote technologies for leak detection
- ► The goal of an eventual initial public offering (IPO) of stock (now expected in 2024-25).

As the country's designated "single buyer," QazaqGaz purchases gas from upstream producers (for domestic consumption), handles gas import purchases, and dispatches Kazakh-produced gas destined for export. The logic of putting Kazakhstan's gas production and acquisition in the hands of a single national operator is to:

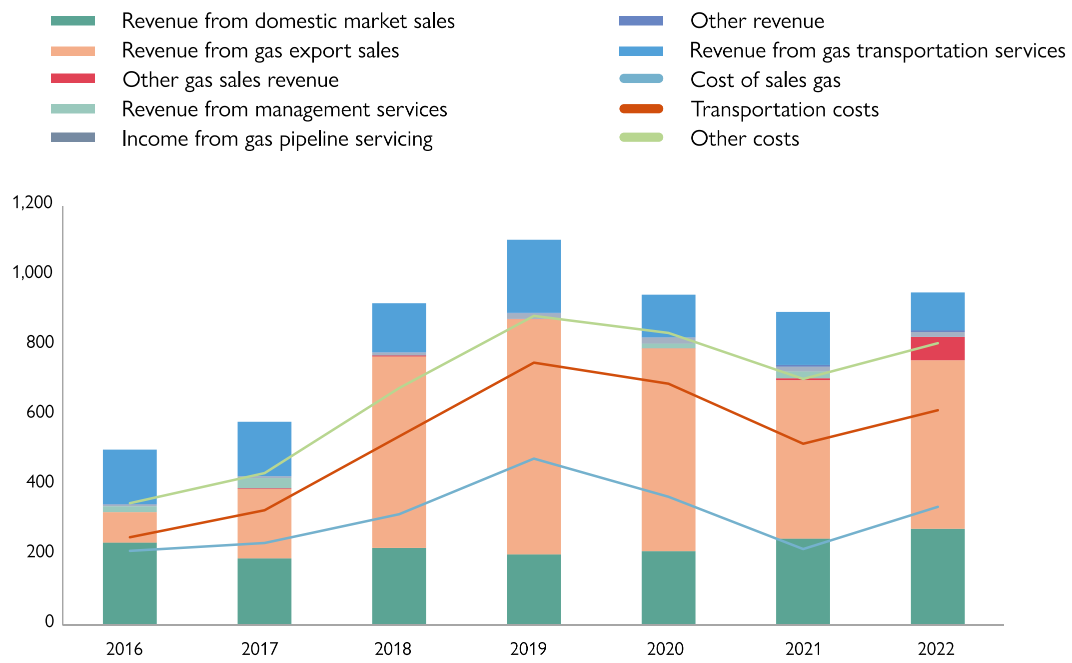
- ► Empower QazaqGaz to ***develop the domestic market and pipeline infrastructure*** through revenues derived from sales to domestic consumers and from exports and gas transit
- ► Enable the state-owned entity to ***capture any upside*** from the difference between producer prices and higher domestic end-user and export prices
- ► ***Maintain a single channel for export***s, which harmonizes with the near-monopoly situations in its two main gas-purchasing customers, Russia and China, as well as with conditions Kazakhstan wants to continue in the forthcoming EAEU single market.

QazaqGaz derives its revenues from three key operating activities (gas sales to the domestic markets, exports, and gas transit) as well as several auxiliary activities (e.g., pipeline servicing) (see Figure 6.6 QazaqGaz reported revenues by source of activity and costs of goods sold). Given that (regulated) low end-user prices (which do not fully cover its production and transportation costs) reverberate throughout the value chain, QazaqGaz generates financial losses in its basic business of selling gas to domestic consumers. Between 2015 and 2021 the company incurred a total of 587 billion tenge ($1.38 billion) in losses on domestic gas deliveries. QazaqGaz estimates its losses from domestic market sales may reach 1 trillion tenge ($2.2 billion) for the period 2022-26 if no changes are made to domestic marketing operations.

Nonetheless, since 2016 QazaqGaz has generated positive net income in its overall operations, thanks entirely to additional revenues from expanded gas exports to China (since 2018) and higher gas transit (since 2016) (see Figure 6.7 Consolidated financial results for QazaqGaz). In 2018, Chinese export revenues jumped to $1.43 billion, up from $0.59 billion in 2017. In 2022, export revenues amounted to $1.01 billion, similar to the 2021 value of $1.05 billion, reflecting relatively higher unit gas prices in 2022 despite lower exports. Thus, availability of gas for exports has important implications for the company's overall business operations and viability.

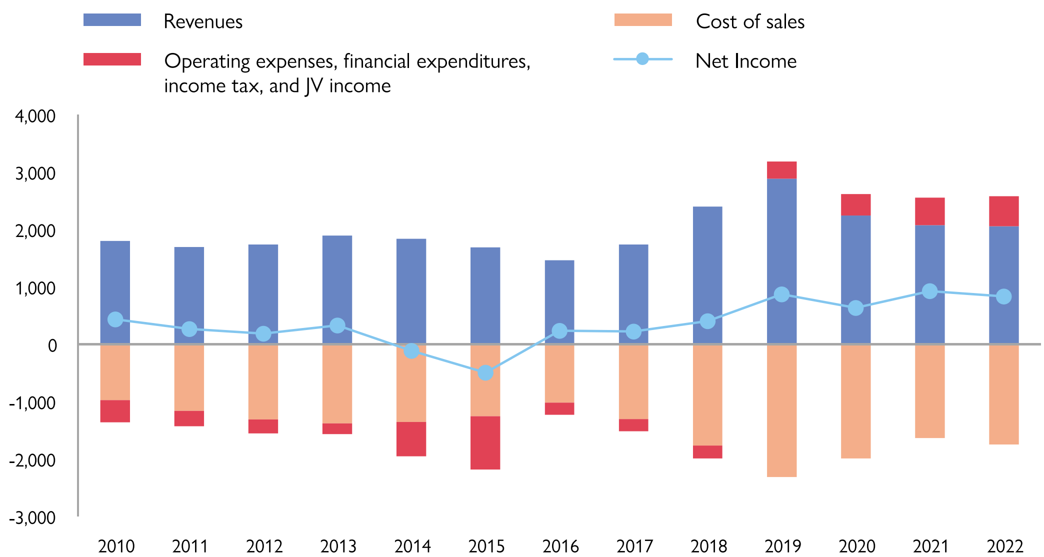
Yet further gasification means that the unprofitable segment of QazaqGaz's business will continue to grow, while export volumes are likely to shrink, given the constraints on available supplies of commercial gas in Kazakhstan. For this reason, QazaqGaz has championed a number of changes in domestic gas pricing policy and the investment environment that are described later in this report. The company continues to push for additional amendments to encourage upstream gas developments and expanded flexibility to adjust regulated prices and tariffs.

Figure 6.6 QazaqGaz reported revenues by source of activity and costs of goods sold (billion tenge)



Source: QazaqGaz financial reporting, S&P Global Commodity Insights. © 2023 S&P Global.

Figure 6.7 Consolidated financial results for QazaqGaz (million US$)



Source: QazaqGaz financial reporting, S&P Global Commodity Insights. © 2023 S&P Global.

6.5 Stimulating Greater Investment in Exploration and Upstream Activity

In order to secure the substantial incremental volumes of gas called for in the Comprehensive Plan, to reach 42.1 Bcm of commercial gas by 2030 (from 35.7 Bcm in 2022), policymakers in government and in the national companies KMG and QazaqGaz are looking at various ways to stimulate investment in upstream exploration and production. Two prominent approaches that have emerged focus on: (a) lowering the costs of exploration and production from new fields and improving the legal environment surrounding their licensing (embodied in the Improved Model Contract); and (b) increasing the prices that producers receive for gas from these new developments.[20]

6.5.1 Improved Model Contract

The initial impetus to create the Improved Model Contract (IMC) emerged from a November 2020 meeting of the Foreign Investors Council (FIC), an advisory body to the Kazakh government established in 1998 to promote dialogue between state authorities and foreign investors.[21] There, the Kazakh leadership and major investors discussed the progress being made in drafting an IMC.

The key problem IMC attempts to address is mitigating the high costs of upstream development in Kazakhstan, where much of hydrocarbon reserves are found in difficult, "complex" fields. The economics of offshore Kazakh projects are also challenged by the heavy dependence on imported equipment and services and the difficult logistics of bringing them to the field. There was a broad understanding that the way to address this problem of high costs was to offer regulatory and fiscal terms that offer stability and lower taxes to help reduce overall and upfront costs of upstream development.

In January 2023, Kazakhstan's long-awaited IMC went into effect, and soon thereafter, on 6 February 2023, Kazakhstan's Ministry of Energy and KMG signed the first subsoil use contract based on the IMC for the production of hydrocarbons at the Kalamkas More, Khazar, and Auezov offshore fields in the Caspian Sea. Russia's Lukoil is KMG's strategic partner in the project and will enter the project on a 50-50 basis.

In June 2023, the Ministry of Energy and KMG concluded another IMC contract for the complex onshore Karaton-Sarkamys field. Russia's Tatneft signed an agreement of intent to implement the Karaton-Sarkamys exploration project with KMG and to provide carry-financing.

Therefore, it can be said that the IMC already has been successful in attracting two foreign investors' participation in a major project, but Kazakhstan is clearly hoping for additional projects. A key metric for its success will be the signing of contracts with other operators, particularly Western international majors. Given the current geopolitical situation, Russian investors do appear to carry additional risks to the implementation of the projects.

6.5.1.1 The IMC applies only to "complex" fields

The Improved Model Contract is designed to incentivize both oil and gas development upstream. Importantly, the IMC only applies to new "complex" projects (in undeveloped fields, even if the actual reserves have already been discovered). It does not apply to other types of deposits, or to contracts concluded before the introduction of the IMC, nor does it apply to their subsequent extensions.[22] More specifically, the IMC applies to three categories of complex fields:

- *Offshore fields* that are fully or partially located in the Kazakh sector of the Caspian or Aral seas
- *Onshore fields* where one of the following applies:
    - Contain unconventional hydrocarbon reserves
    - Have hydrocarbon reservoirs at 4,500 meters or deeper
    - Have a hydrogen sulfide content in the formation fluid of 3.5% or more
    - Have deposits with abnormally high reservoir pressure with an anomaly coefficient of 1.5 or more[23]
    - Have subsalt reservoirs with a salt layer thickness of more than 100 meters
    - The discovered reservoirs are considered non-structural traps.
- *Onshore gas projects,* including gas or gas condensate projects or projects where oil-saturated accumulations account for less than a quarter of the total volume of hydrocarbons in the field.

20 Kazakhstan has taken other important steps in recent years to improve the regulatory framework governing upstream investment as well, especially through implementation (starting in 2018) of amendments to both the Tax Code and the Subsoil and Subsoil Use Code.

21 For additional details about the Improved Model Contract and the Kalamkas More–Khazar project approved on its basis, see S&P Global Commodity Insights, Regional Integrated Insight, *Kazakhstan's Long-Awaited Improved Model Contract for Hydrocarbon Exploration and Production Signed into Law: Have conditions improved enough to spur new upstream exploration?* 13 March 2023.

22 However, there is a process whereby operators of fields regulated under existing standard subsoil contracts can retroactively apply for IMC terms for subsoil plots that otherwise meet the geological criteria listed for a complex deposit, provided that: they are still at the exploration stage (onshore and offshore fields) or at the exploration or production stage (onshore gas project); have no unresolved violations of obligations under the original contract; and have fully completed the scope of work outlined in the work program for their specified "exploration period." The exploration period is determined as the maximum exploration period determined under the provisions of Articles 116-117 of the Subsoil Code, minus the actually utilized exploration period under the previous subsoil use contract.

23 The anomaly coefficient is the ratio of reservoir pressure to hydrostatic pressure with a fluid density of 1,000 kg per cubic meter in the wellbore.

6.5.1.2 Regulatory and fiscal preferences in the IMC

Incentives for investors (in the form of regulatory and fiscal preferences) embodied in the IMC include the following:

- For dispute settlements, parties can specify in the IMC whether to settle disputes in the courts of the Republic of Kazakhstan or through international arbitration in one of four locations: the Astana International Financial Center, London, Geneva, or Singapore (Article 11 of IMC)
- An option to use an alternative (profit-based) subsoil tax regime at significantly reduced rates for complex offshore projects; tax rates vary based on global oil prices
- Simplified licensing process for the transition from exploration to production activities
- Stability for certain fiscal terms and preferences, but not all:
  - For offshore and complex onshore fields, stable preferences include the manner in which the initial cost of assets is determined
    - The coefficients applicable in calculating expenses for geological study, exploration, and preparatory production work in the period between a commercial discovery and the start of production
    - Coefficients for determination of depreciable expenses incurred by the subsoil user during the period after commercial discovery until the start of production: 1.5 times for complex onshore fields and 2.0 times for offshore fields
    - The process of determination of depreciation percentages for each asset subgroup
    - No property tax payments
  - For all three types of complex hydrocarbon projects, excess deductions from calculating the alternative tax on subsoil use over the amount of the total annual income can be carried over to the next period for the following 10 years
  - For complex offshore projects, the Tax Code provides for lower Alternative Subsoil Use Tax (ASUT) rates (one-third of the usual rate)
  - For onshore gas projects, the IMC guarantees stability of the clause in the reduction of corporate income tax by up to 100% for a period of 10 years after the start of production
  - The above preferences apply from the date of registration of an IMC for complex projects until the expiration of 20 calendar years from the date of commencement of hydrocarbon exports extracted under the relevant subsoil use contract
- Temporary exemption for the subsoil user of a complex project from export customs duties (export tax) on crude oil: 20 years from the start of crude exports for offshore and onshore gas projects and 10 years for complex onshore projects
- For the fields qualified under the IMC, the contract lifts the mandatory requirement to supply at least 25% of total crude oil output to the domestic market; however, the subsoil user has the option to supply the domestic market if it wishes.[24]

24 Any oil or gas produced during the *exploration* phase must be supplied to domestic market.

The IMC does not offer stability in other taxes or potential new taxes. The contract specifically states that tax obligations are established for the subsoil user in accordance with Kazakhstan's current tax legislation and only select preferences, specified by the Article 722-1 of the Tax Code, are stable as of the date of signing the contract. Stability also does not apply to environmental legislation or the legislation on competition protection.

Specifically, the Subsoil Code guarantees that amendments and additions to Kazakhstan's legislation that negatively affect the economics of a subsoil user's projects do not apply to contracts concluded before such amendments and additions are adopted. However, these guarantees are not immune to future changes in regulations governing national security, defense, environmental safety, health care, taxation, customs, and protection of competition. The only exception to what is specified in the Subsoil Code applies to customs regulation, which provides temporary exemption from crude oil export customs duties produced under the IMC for complex projects. Also, all existing procedures for the approval of basic project documents such as industrial safety or environmental analysis, required by the current legislation on subsoil and subsoil use, are maintained and applied to IMC.

6.5.1.3 Obligations in the IMC

In addition to regulatory and fiscal preferences (i.e., incentives), the IMC also specifies a number of obligations of the subsoil user, which if unfulfilled can result in fines and other penalties up to the termination of contract. These requirements include the following:

- Local content requirements for *specialists and workers* of at least 70% (for a simple [not improved] typical model contract, this share is 50%); other percentages for managers or structural division chiefs cannot be lower than 50%. At the same time, the IMC states that the subsoil user can attract the necessary foreign labor to conduct subsoil operations.
- Mandatory creation of a program to develop local *suppliers* of goods, works, and services during the production period, approved and overseen by the competent authority. The 50% minimum requirement in the previously existing model contract does not apply to the Improved Model Contract for complex fields.
- If one of the subsoil users is a foreign legal entity, contracts are drawn up in three languages (English, Kazakh, and Russian), with preference given to Kazakh- and Russian-language texts.
- Obligation to develop and fulfill the work program indicating the scope, type, and timing of exploration work broken down annually (in the previously existing contract, the program is created for the entire exploration period, not by annual increments) (Article 7).
- A new Paragraph 12 in the IMC, titled "Additional Obligation of the Subsoil User," adds a requirement in the case of a large discovery. It states that if initial hydrocarbon reserves exceed 100 MMt of oil or 50 Bcm of natural gas, after 20 years

from the date of commencement of the export of hydrocarbons produced under the contract, the subsoil user must implement one of the following obligations:

- Creation of processing industries independently through the creation of a new legal entity or jointly with others
- Modernization or reconstruction of existing extractive facilities
- Supplying produced hydrocarbons for processing to downstream processing enterprises (manufacturing) in Kazakhstan on contractual terms
- Implementation of another investment project or a project aimed at the socioeconomic development of the region, independently through the creation of a new legal entity or jointly with others.

6.5.1.4 Overall assessment of the IMC

Although the IMC is indeed an encouraging step in the right direction, we assess that the IMC alone is not likely to incentivize commercial natural gas production to the degree necessary to ensure substantial incremental commercial gas supply in Kazakhstan. When compared with the terms offered by countries that have been successful in attracting international E&P capital recently, it may still fall short. Globally, the uncertainty over the longer-term hydrocarbon demand trajectory, limited investor appetite, and the impact of the energy transition are forcing E&P companies to be selective in which greenfield projects they pursue.[25] Operators now tend to focus on “advantaged” barrels and fields with proven reserves, near existing infrastructure, or that afford relatively fast return on investment, like shale plays. Upstream operators worldwide have largely shifted from expensive, large-scale, single-project investments to small- or medium-scale projects, and those ventures with multiphase expansion opportunities with economical break-even prices are expected to account for the majority of new-source conventional crude oil production over the next two decades. The gains that larger operators have made since 2014 in reducing cycle times are allowing them to commit to fast-tracking successful “emerging” basins such as Guyana/ Suriname and Namibia.

Although global upstream investment has been rising from a trough in 2020, this is mostly on account of upstream capital investment instead of exploration. Meanwhile, companies are cutting exploration financing and budgeting—the most direct and riskiest form of value addition in the upstream. The scale of global exploration is declining, with the number of players and the size of the effort constricting, with annual average wildcat well numbers declining.[26] Currently, even though companies are relatively flush with cash, they are not returning to even the pre–COVID-19 level of exploration activity. Generally, oil and gas companies are showing restraint with investment into the hydrocarbon sector, notwithstanding a renewed focus by policymakers on the adequacy of near-term supply reflecting national security concerns (see Chapter 2).

Kazakhstan faces these challenges along with numerous other factors associated with its land-locked location in Eurasia, neighboring a key transit country (Russia) that is handicapped by international sanctions. This means that for Kazakhstan to attract quality upstream investment, it needs not only to introduce improved terms, but—for lack of a better term—the *best* terms.

The introduction of the IMC undoubtedly will help to de-risk upstream development of Kazakhstan’s complex fields. However, despite notable improvements, the IMC retains elements whereby the investor is not fully protected against arbitrary unilateral decisions by the state. More specifically:

- The IMC fails to provide full long-term tax guarantees throughout the duration of a typical project (25–45 years).
- The IMC leaves the door open for changes in legislation (i.e., new regulations governing national security, defense, environmental safety, health care, taxation, customs, and protection of competition) that have the potential to greatly alter project economics.

The contract’s new obligations for subsoil users (e.g., regarding local content) also may discourage some investment vis-à-vis locations where such obligations are not present. Therefore, the IMC by itself has not yet created a dynamic where the government is viewed as a partner and facilitator for investors, in a global environment in which Kazakhstan is competing with other countries for limited upstream investment funds.

However, Kazakhstan is working to further develop its economy. In September 2023, in accordance with the Decree issued by President Kassym-Jomart Tokayev, the Plan for Implementation of the Measures Outlined in the “Economic Course of a Fair Kazakhstan” Address was approved, encompassing the country’s gradual transition to a new economic development model and an increase in its investment attractiveness.[27] It will include:

- Simplifying and shortening of the procurement process (based on the principle of prioritizing quality over price, and full automation of procedures).
- Attracting large private investments in order to unlock the sector’s potential.
- Granting priority [preferential] subsoil use rights to investors carrying out geological exploration at their own expense.
- Reducing the project approval timeframe and procedures by half through the introduction of a comprehensive state expert review and full digitalization of the process.

25 Although the focus of interest here is on gas, and not liquids, because of the fact that most prospective gas reserves in Kazakhstan consist of associated gas (combined with liquids in the field), liquids demand is often the primary driver of investment decisions.

26 S&P Global Commodity Insights, Executive Briefings, *Global Upstream: Top trends for 2023*, 1 February 2023.

27 https://www.pnp.ru/top/site/kasym-zhomart-tokaev-provozglasil-ekonomicheskiy-kurs-spravedlivogo-kazakhstana.html.

- Resetting the tariff policy, introducing new tariff-setting methodologies, and increasing the sector's investment attractiveness.
- Introducing adequate market tariffs for 5-7 years for all natural monopolists. A guaranteed long-term tariff will allow for planning investments and serve as "hard" [reliable] collateral when obtaining loans.
- It is also important to attract investment in the exploration and development of new gas fields. Oil and gas giants – Tengiz, Kashagan, Karachaganak – should be reliable suppliers of affordable gas.
- Preferential treatment should be granted according to clear rules, without connection to individual projects or persons.
- Transferring tax administration to a service-type model of interaction between fiscal authorities and taxpayers with the goal of warning rather than punishing.
- Complete digitalization of tax control, reduction of tax reporting forms by 30%; reduction of the total number of types of tax payments and other obligatory payments to the budget by 20%.

6.5.2 The new producer price framework for incentivizing exploration

At the end of 2022, the government of Kazakhstan passed important amendments to the Law on Gas and Gas Supply that aim to incentivize new gas production by offering higher producer prices for "new" output. "New" gas is defined as gas from new projects (contracts sighed after 1 January 2023) or incremental output from existing ones, where the gas output is higher than the arithmetic mean of the annual sales of commercial gas to the national operator for five consecutive calendar years preceding 2023.

For all new gas, the new producer price will be a weighted sum of the domestic and export parity price, adjusted for transportation costs[28], a commission for QazaqGaz, and a field complexity index, where:

$$\mathbf{P_{producer} = 70\% * P_0 + 30\% * P_{domestic}}$$

$$\mathbf{P_0 = C_{complexity} * (P_{export} - T_{transport} - QG_{commission} - I_{investment})}$$

$\mathbf{P}_{producer}$ – producer price at which the national operator purchases new gas, in tenge per Mcm;

$\mathbf{P}_{domestic}$ – the average (arithmetic mean) wholesale price of commercial gas on the domestic market, approved for the current calendar year;

$\mathbf{P}_{export}$ – the current export price of commercial gas at the border of the Republic of Kazakhstan with the People's Republic of China, determined on the basis of information received from the national operator;

$\mathbf{T}_{transport}$ – pipeline transportation costs from the subsoil user to the border with China, in tenge per Mcm;

$\mathbf{QG}_{commission}$ – national operator's profitability component of up to 10% of the current export price of commercial gas at the Kazakh-Chinese border (excluding gas transportation costs through the gas pipeline network from the subsoil user to the border with China), in tenge per Mcm;

$\mathbf{I}_{investment}$ – expenses for the transportation of commercial gas to the planned place of sale to the national operator, determined on the basis of tariffs approved by the authorized body in charge of natural monopolies and regulated markets, in tenge per Mcm;

$\mathbf{C}_{complexity}$ – the field development complexity factor is based on satisfying a definition for a complex field as specified in subparagraphs 1) and 2) of paragraph 1-2 of Article 36 of the Code of the Republic of Kazakhstan "On Subsoil and Subsoil Use."

- The coefficient equals 1 if one of the two parameters are satisfied
- The coefficient equals 0.8 if the two parameters are not satisfied.

The parameters as described in the subparagraph 1 refer to offshore fields and in subparagraph 2 refer to complex onshore fields with at least one of the specified criteria fulfilled. The definition of complexity coefficient means that simpler onshore gas fields get the lower 0.8 coefficient applied to their gas price. These are the fields where QazaqGaz is currently focusing its attention. Naturally, the national operator is proposing further amendments to the Law "On Gas and Gas Supply" to allow for even better prices.

With the currently established more favorable producer prices and the preferences incorporated in the Improved Model Contract, the government optimistically estimates possible additional gas supply on the order of 4.2-6.7 Bcm/y by 2030.

For subsoil projects concluded before 1 January 2023 and not increasing their gas output, the prior price arrangement, established through a "cost-plus" price mechanism, still holds:

> **Production cost ($/Mcm) + processing cost ($/Mcm) + transmission tariff to point of sale to QazaqGaz ($/Mcm) + profit margin (< 10%).**[29]

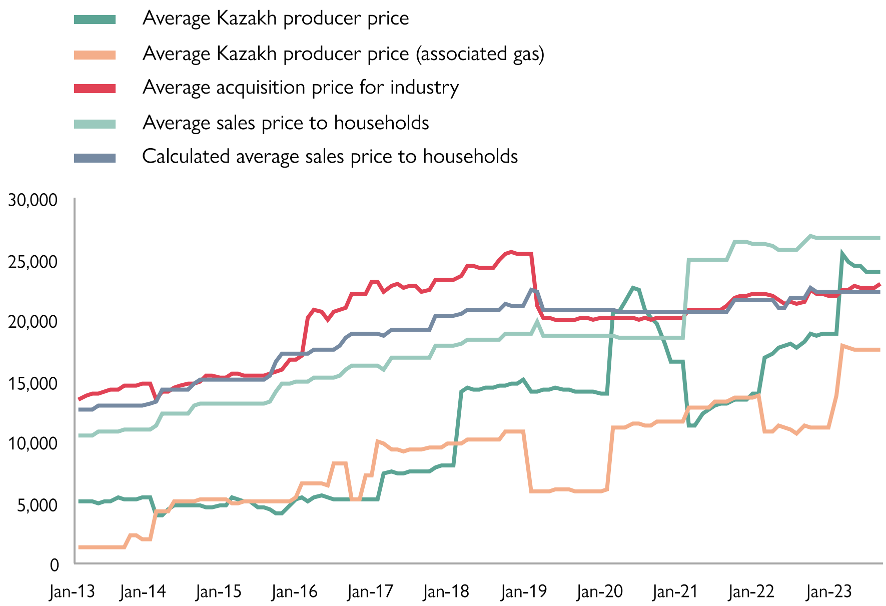
The introduction of higher producer gas prices is a welcome development, although any success remains contingent on the continuing reforms that ensure end-user prices rise to eventually reflect at least the total costs of delivered gas. The still relatively low regulated end-user prices pressure all aspects

28 Transportation costs are separated in the legislation to include (1) transportation costs to the point of sale to QazaqGaz and (2) across Kazakhstan to the national border.

29 Kazakhstan's Law on Natural Monopolies and supporting rules issued by KREM establish a methodology to calculate an acceptable profit rate for gas transportation companies (KTG and subsidiaries) based on their regulated asset base, which reflects their expenditures and investment programs. In practice, determination of end-user prices still follows a "cost-plus" approach where an acceptable profit rate is believed to be no more than 10%.

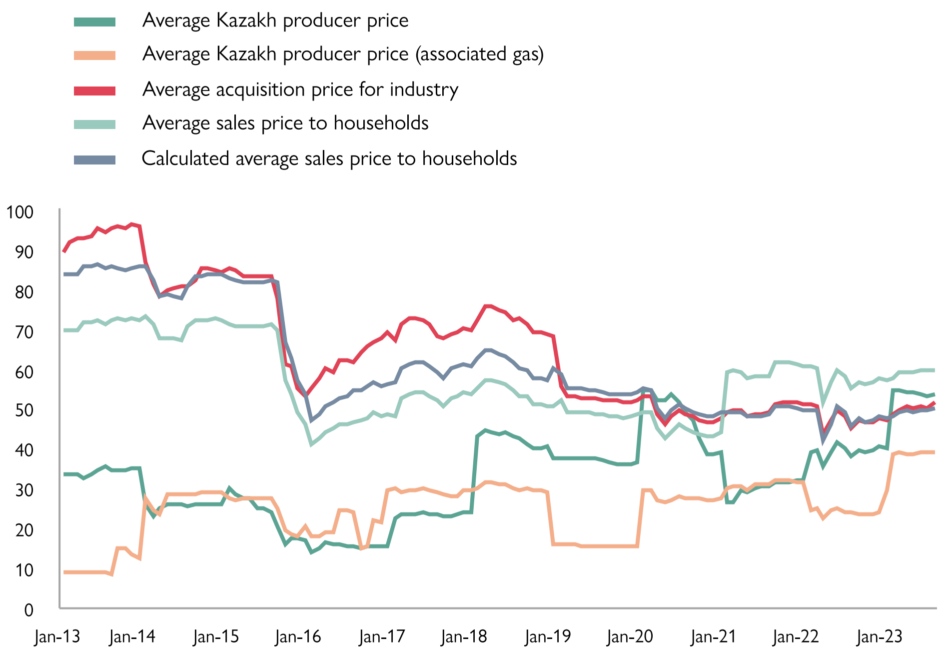
of the domestic gas value and force QazaqGaz to drive a hard bargain in negotiating gas prices with gas producers. In 2022, the average producer price for natural gas was 18,139 tenge/Mcm ($39.5/Mcm), and by June 2023 it was up to 24,008 tenge/Mcm ($53.5/Mcm) (see Figure 6.8 Monthly trends in domestic gas prices in Kazakhstan (tenge/Mcm) and Figure 6.9 Monthly trends in domestic gas prices in Kazakhstan ($/Mcm)). The average producer price for associated gas was 11,371 tenge/Mcm ($24.7/Mcm) in 2022, and 17,596 tenge/Mcm ($39.2/Mcm) in June 2023.

Figure 6.8 Monthly trends in domestic gas prices in Kazakhstan (tenge/Mcm)



Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

Figure 6.9 Monthly trends in domestic gas prices in Kazakhstan ($/Mcm)



Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

6.6 Natural Gas Production

6.6.1 Recent trends

In 2022, Kazakhstan's gross gas production was reported as 53.2 Bcm, slightly lower compared to 54.2 Bcm in 2021.[30] A reduction in gross output was in part a result of lower production at Kashagan (although this was largely offset by increases at Tengiz and Karachaganak). However, 2022 gross gas output was also lower for more than half of the other gas producers in Kazakhstan, corresponding to the oil production declines in 2021-22. For 2023, S&P Global estimates gross production to reach about 57 Bcm.

Volumes of commercial gas, excluding reinjected volumes, amounted to 36.0 Bcm in 2022 versus 36.8 Bcm in 2021, continuing a declining trend ongoing since 2019 (see Table 6.4 Kazakhstan's natural gas balance 2015-23).[31] For 2023, commercial gas production is expected to reverse the declining trend and grow to 37 Bcm, driven in large part by rising Kashagan output.

Most of the gas produced in Kazakhstan is a by-product of oil production (associated gas), with a large share of the remaining gas output coming from the Karachaganak field, also primarily designed to extract liquid hydrocarbons (e.g., gas condensate) (see Figure 6.10 Gas production in Kazakhstan: Associated versus non-associated). In 2022, 61.5% of gross gas production was associated gas, and another 36.5% was the "natural" gas from Karachaganak. The share of the remaining natural gas was less than 2% in 2022. This heavy dependence on associated gas makes it difficult to scale commercial gas output in response to demand. The "Big 3" projects – Tengiz, Karachaganak, and Kashagan – accounted for 81.6% of Kazakhstan's gross gas production in 2022 and 73.1% of commercial gas production (see Figure 6.11 "Big 3" share in commercial gas production in Kazakhstan). The "Big 3" have considerable reinjection needs for pressure maintenance and enhancement of liquid hydrocarbons recovery, although reinjection at a smaller scale also occurs at several smaller producers in Kyzylorda and Mangystau oblasts.[32] In 2022, total reinjection amounted to 17.2 Bcm or 32.3% of gross output, versus 17.3 Bcm (32%) in 2021. Over the past decade, the share of reinjection remained at around 25%-38% of gross output (see Figure 6.12 Kazakhstan's gross and commercial gas production). Going forward, reinjection is expected to remain an important, economically effective gas utilization option for upstream operators.

Table 6.4 Kazakhstan's natural gas balance 2015-23 (Bcm/y)

	2015	2016	2017	2018	2019	2020	2021	2022	2023*
Production (gross)**	45.3	46.4	52.9	55.5	56.4	55.4	54.2	53.2	56.6
Production (commercial output)	28.4	35.2	39.8	41.2	41.0	38.1	36.8	36.0	36.9
Imports	4.9	5.8	5.1	5.7	8.8	4.3	9.3	7.4	6.4
Exports	13.3	12.8	16.8	19.1	19.4	16.7	14.8	13.0	12.2
Net exports	8.5	7.0	11.8	13.4	10.6	12.4	5.5	5.6	5.8
Apparent consumption (commercial gas)	20.7	27.4	27.9	27.9	29.4	29.3	30.6	30.4	31.1
Consumption (end-of-pipe deliveries)	12.0	13.1	14.0	15.1	15.9	17.1	18.6	19.3	20.0

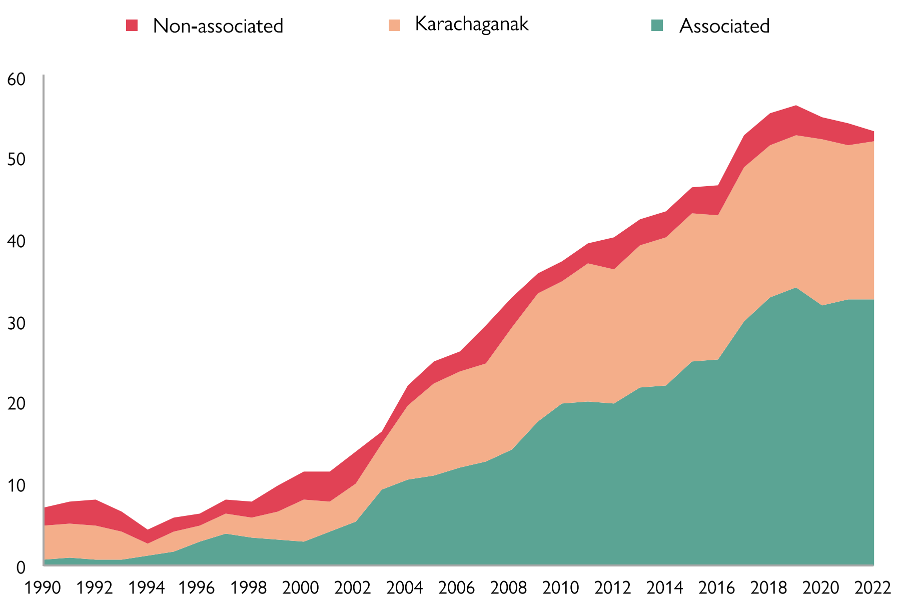
Notes: *Data for 2023 are estimated; **Including re-injected volumes.
Source: S&P Global Commodity Insights.

30 Some official data (IACNG, KazStat) still report gross gas production for 2021 as 53.8 Bcm.

31 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 on-site project use and distribution to consumers.

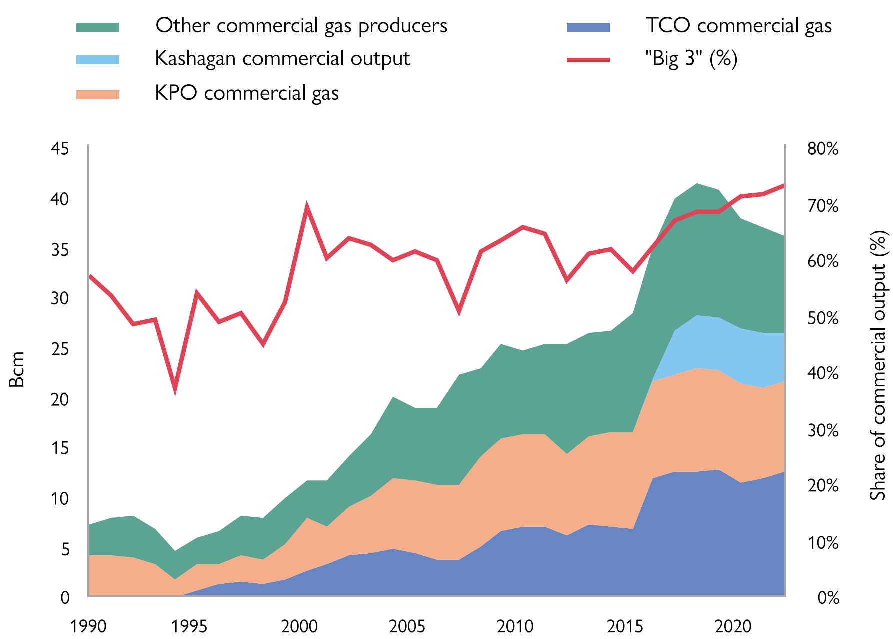
32 Currently, seven out of 80 subsoil users operating in Kazakhstan reinject associated gas back into reservoir to maintain liquids production, according to the Prime Minister of the Republic of Kazakhstan, Alikhan Smailov; see *Kapital*, https://kapital.kz/economic/117771/na-baze-kashagana-realizuyet-sya-dopolnitel-nyy-proyekt-gazopererabatyvayushchego-zavoda.html, accessed 31 July 2023.

Figure 6.10 Gas production in Kazakhstan: Associated versus non-associated (Bcm/y)



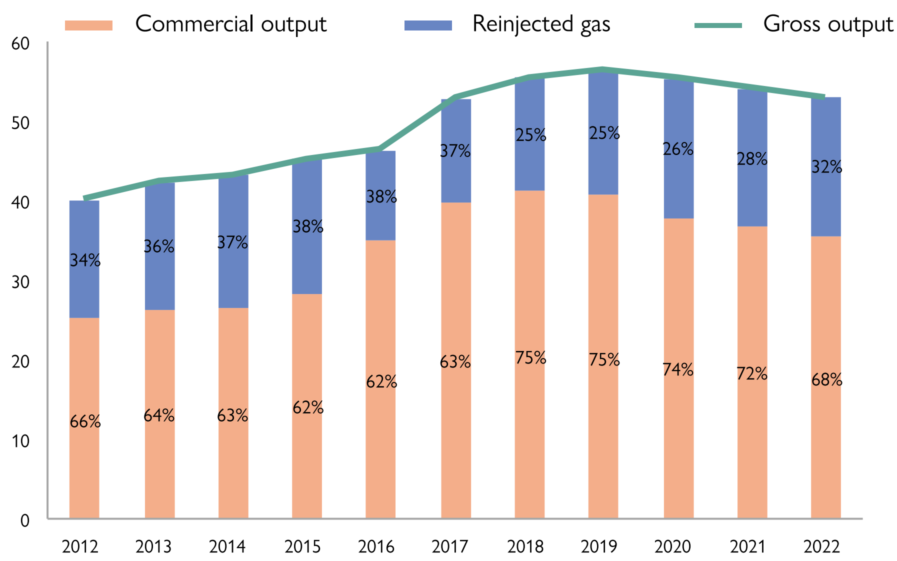
Notes: Gross production, including reinjected volumes.
Source: S&P Global, Kazakhstan's Bureau of National Statistics, Ministry of Energy of Kazakhstan.

Figure 6.11 "Big 3" share in commercial gas production in Kazakhstan



Source: S&P Global Commodity Insights.

Figure 6.12 Kazakhstan's gross and commercial natural gas production (Bcm/y)



Source: S&P Global Commodity Insights.

6.6.2 S&P Global's base-case gas production outlook

S&P Global's outlooks for Kazakhstan's natural gas production to 2050 are tied to those for Kazakhstan's liquids production (see Figure 6.13 Outlook for Kazakhstan's gross gas production by scenario).[33] The government's official production outlook is presented below. In the S&P outlook, increases in gas production over the medium time frame largely depend on timing of expansion phases of the mega-projects, particularly Kashagan; expanded production from "new" field development by KMG and QazaqGaz is likely to be less decisive, particularly in the medium term.

In the base case, gross gas output will likely peak in 2030 at about 70 Bcm/y, as subsequent (slower) growth in mega-projects fails to offset declines elsewhere. Post-2030, gas production enters a period of steady decline, contracting to about 50 Bcm/y by 2050 (see Table 6.5 Kazakhstan's natural gas balance: S&P Global base-case outlook 2020-50). Between 2022 and 2030, almost all of the net increase in gross gas output (16.1 Bcm) is expected to come from the "Big 3" projects – Kashagan (6.1 Bcm), Tengiz (4.6 Bcm) and Karachaganak (5.9 Bcm), while gross output from other sources (primarily mature fields) is slated to decline by around 0.5 Bcm. By 2030, KPO will remain the largest gross gas producer (25.3 Bcm in 2030), with commercial output at about 11 Bcm. By 2050, the main gas producers will be Karachaganak (18.0 Bcm gross, 9.0 Bcm commercial), Kashagan (16.6 Bcm gross, 10.0 Bcm commercial), and Tengiz (5.3 Bcm gross, 5.0 Bcm commercial). Gas output from other producers is set to continue to contract, with declines in mature fields failing to offset gas production increases in the "other offshore" category.[34]

33 For descriptions of the three scenarios' underlying assumptions, please see Chapter 1 of this report.

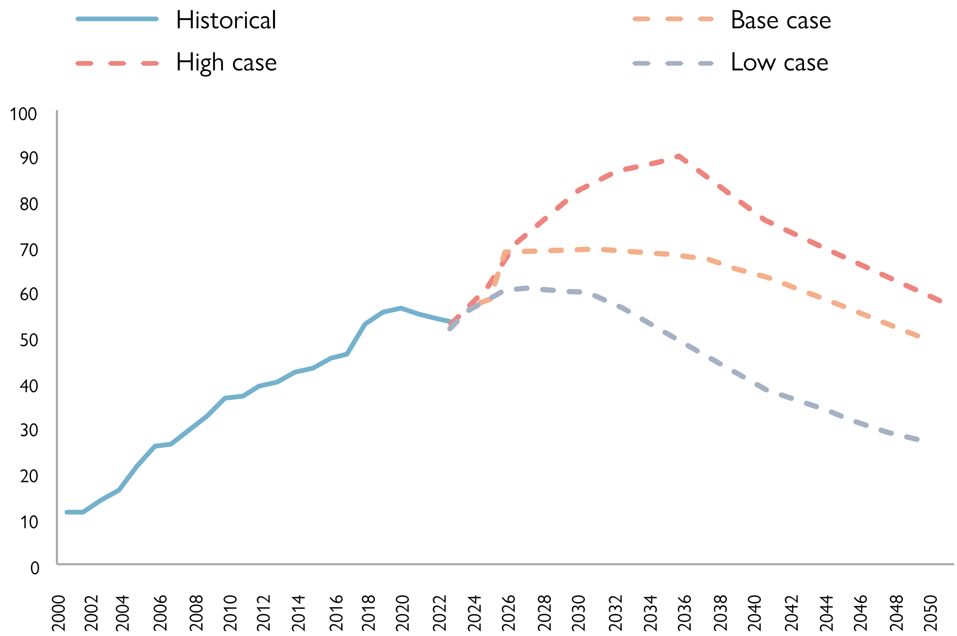
34 S&P Global expects that gas production in the "other offshore" category, i.e., other than Kashagan, will have significant reinjection needs, with most of the gas reinjected into reservoir, however, some gas production is likely to be processed into pipeline-quality gas and delivered to end-users.

In the high production case, corresponding to the high production case in oil output, gas production peaks at almost 90 Bcm in 2035 and then declines to 58 Bcm by 2050. In the low production case, Kashagan phase 2 does not materialize, and gas production peaks at 61 Bcm in 2025 and declines to 27 Bcm by 2050.

Commercial volumes will likely peak somewhat later, in the mid-2030s, at around 42 Bcm/y, as construction of new gas processing capacity will take some time. After 2035, commercial output begins declining due to sustained high reinjection needs, limited further expansion in gas processing capacity, and challenges to commercial use posed by low producer and end-user prices (as discussed below). Commercial production from the "Big 3" is expected to follow a similar trajectory, peaking in 2035 and declining slowly thereafter. Karachaganak's commercial gas output remains stable through 2045 at about 10-11 Bcm/y, while Tengiz's commercial gas deliveries peak during 2025-30 at around 12.5 Bcm/y, and decline slowly thereafter. At Kashagan, commercial gas output rises to 10 Bcm by 2035 (assuming completion of new gas processing facilities near the Bolashak oil and gas treatment complex) and remains at that level through the forecast period (see Figure 6.14 Kazakhstan's gas production profile to 2050: S&P Global base-case outlook).[35] The new gas processing plant near Bolashak, with capacity of 1.0 Bcm/y of raw gas (yielding 750 MMcm/y of dry gas) is already under construction, due to be completed by 2025. The S&P Global outlook also assumes that gas processing at Kashagan will expand further in several phases, adding a total of 4 Bcm/y by 2035 (the official due date is much sooner, in 2028-29). A 5 Bcm/y gas processing facility at Karachaganak is also expected to be launched in 2032 (the official launch date is 2028).

35 In December 2021, QazaqGaz (then NC KazTransGas JSC) and the NCOC partners signed an agreement on joint work on the basic engineering of Phase 2A of the Kashagan project. Phase 2A (currently under review) would increase total liquids output to 500,000 b/d (23.7 MMt/y) with an option of an additional 2 Bcm/y of raw gas supplied to an expanded QazaqGaz gas processing plant. An FID is expected in 2023, with project start-up in 2026 (capex $1.6-$1.8 billion). Phase 2B would bring NCOC's total liquids production to 700,000 b/d. An additional 6 Bcm/y of raw gas would be made available, either for a new processing plant or perhaps for TCO's existing facilities to utilize. An FID is expected in 2024, with project start-up in 2030 (capex $3.0-$3.5 billion).

Figure 6.13 Outlook for Kazakhstan's gross gas production by scenario (Bcm)



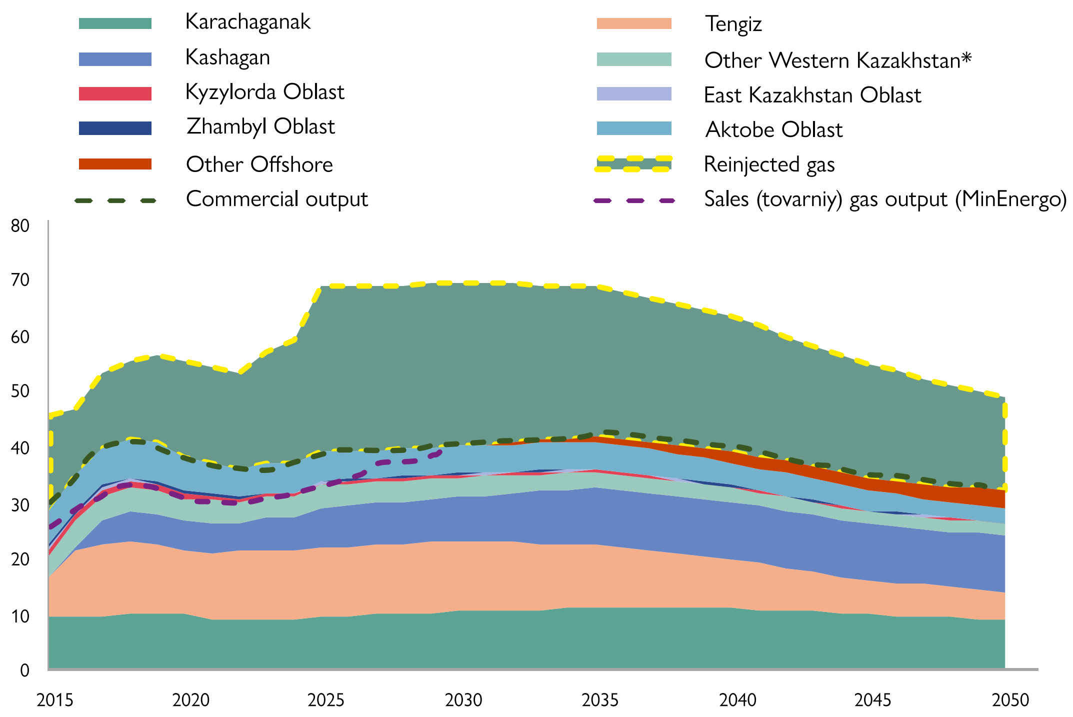
Source: S&P Global Commodity Insights.

Table 6.5 Kazakhstan's natural gas balance: S&P Global base-case outlook 2020-50 (Bcm/y)

				S&P Global forecast							
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Production (gross)*	55.4	54.2	53.2	56.7	59.2	68.5	69.3	68.5	63.2	54.6	48.8
Production (commercial output)	37.8	36.8	36.0	37.0	36.8	38.9	40.1	41.9	39.2	34.5	31.9
Imports	4.3	9.3	7.4	6.4	5.5	4.9	5.6	5.5	9.5	10.8	11.6
Exports	16.7	14.8	13.0	12.2	11.5	12.7	14.4	14.7	13.6	9.5	6.7
Net exports	12.4	5.5	5.6	5.8	6.0	7.8	8.8	9.2	4.1	-1.3	-4.9
Apparent consumption (commercial gas)	25.4	31.3	30.4	31.1	30.7	31.1	31.3	32.7	35.1	35.8	36.8
Consumption (end-of-pipe deliveries)	17.1	18.6	19.2	20.0	20.1	20.5	22.3	25.4	28.9	31.2	33.2

Notes: *Including re-injected volumes.
Source: S&P Global Commodity Insights.

Figure 6.14 Kazakhstan's gas production profile to 2050: S&P Global base-case outlook (Bcm)



Notes: *Other Western Kazakhstan includes fields in the Atyrau, West Kazakhstan, and Mangystau oblasts, excluding the "Big 3."
Here S&P Global defines commercial gas volumes as gross gas production minus reinjected volumes; thus, commercial production includes volumes that disappear as other upstream usage and losses. This is not the same as the volume of "sales gas" production (tovarnoye proizvodstvo) reported by the Ministry of Energy RK, which appears to exclude reinjection, impurities, and other upstream usage and losses.
Source: S&P Global, Ministry of Energy RK.

6.7 Gas processing in Kazakhstan

Another key thrust in the overall drive to increase the availability of commercial gas is to greatly expand gas processing in the country. Most of Kazakhstan's gas output requires processing. There are five 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 (OGPZ). Total capacity of Kazakhstan's gas processing plants in 2023 was 38.8 Bcm/y with a utilization rate of 74% (see Table 6.6 Kazakhstan's gas processing plants). The five main plants are Tengiz (13 Bcm/y capacity in Atyrau Oblast), Zhanazhol (8.4 Bcm/y capacity in Aktobe Oblast), Bolashak (6.3 Bcm/y capacity in Atyrau Oblast), Chinarevskaya GTU (4.2 Bcm capacity in West Kazakhstan Oblast), and KMG subsidiary KazGPZ (1.5 Bcm/y capacity in Mangistau Oblast). Only the Tengiz and Bolashak plants have more complex technology capable of processing sour associated gas, while the other plants are smaller and technologically simpler. Both Tengiz and Bolashak plants are operating at capacity, which means that any additional increases in commercial gas output from these two fields would necessitate construction of new sophisticated GPZs.

Nearly all of Karachaganak's raw (high-sulfur) gas output that is not reinjected (9 Bcm in 2021) is sent across the border to Russia for processing at Gazprom's Orenburg GPZ under a long-term agreement.[36] Part of the commercial gas from the Orenburg GPZ is sent back to Kazakhstan (to QazaqGaz), and the rest previously was sold under export contracts through Gazprom. Since 2018, however, the total volume of "exported" gas has contracted, with the bulk of processed Karachaganak gas redirected towards the Kazakh domestic market. Currently, the Orenburg GPZ is facing technical issues related to the acceptance of additional volumes of high-sulfur Karachaganak gas and needs certain technological upgrades to do this.[37] Although the relationship with the Orenburg GPZ will continue into the future, KPO has proposed building a new 4 Bcm/y gas processing plant in Kazakhstan, tentatively scheduled for completion in 2028.[38] This GPZ was included in the Roadmap for the Implementation of the Gas Strategy and was developed by KPO together with PSA LLP.

In addition to the 4 Bcm/y at the proposed KPO GPZ, Kazakhstan plans to add another 6 Bcm/y of additional gas processing capacity by 2030, thus adding 10 Bcm/y of new processing capacity.

36 KPO sends about 8-9 Bcm/y of raw (sour) gas to the Orenburg GPZ for processing under a GSPA in place through 2038. Kazakhstan (i.e., the joint venture KazRosGaz) receives ~7-8 Bcm of dry, pipeline-quality gas from the plant.

37 Nonetheless, in June 2022, QazaqGaz and Gazprom signed an agreement for 2023, where the Orenburg GPZ is to process over 9.33 Bcm of Karachaganak gas, compared to 8.1 Bcm planned for 2022. According to QazaqGaz Annual Report 2022, the final agreed upon raw gas intake by the Orenburg GPZ in 2023 is 8.7 Bcm.

38 In June 2022, QazaqGaz and Gazprom signed a memorandum of cooperation that envisions an increase in KPO gas processing volumes at the Orenburg GPZ up to 11 Bcm/y.

Total investment needed for the aggregate 10 Bcm/y of new processing capacity is estimated at around $8-9 billion. The other three planned plants include:

- **QazaqGaz GPZ:** This is a new 1.0 Bcm/y raw gas processing plant under construction at the Kashagan field.[39] Dry gas output is expected at 0.750 Bcm/y; capex is about $860 million with a planned launch in 2025.[40]
- **Kashagan 2A GPZ:** Construction of another GPZ with a capacity of 4 Bcm/y based on Kashagan gas output from Phase 2A is currently being discussed.[41] A number of investors have been proposed for this project, including from China (CNPC) and Qatar. In late July 2023, Prime Minister Alikhan Smailov revealed that NCOC shareholders and the operator (NCOC) are implementing the project with 2028 as a planned commissioning date. Capex estimates are likely to be around $4 billion.[42]
- **Zhanaozen GPZ:** KMG plans to build a new Zhanaozen GPZ that should replace the existing (and quite dilapidated) KazGPZ. Construction is now set to begin in the fall of 2023, with the date for scheduled completion consequently pushed back to 2026. The plant's capacity will be 0.9 Bcm/y of raw gas and it will produce 759 MMcm/y commercial gas, 232,000 tons of LPGs, and 82,000 tons of pentane-hexane fraction. Capex is estimated at $372 million (167.6 billion tenge).[43]

Construction of the Zhanaozen GPZ should be comparatively simpler than construction of any of the other three GPZs; its raw gas is a lot less complex than the associated gas at Kashagan. Indeed, S&P Global estimates that the cost of gas processing at Zhanaozen is around $117/Mcm without taking into account other by-products. Meanwhile, complex gas processing capacity at Kashagan requires significantly higher capex per unit of capacity. The estimated indicative recovery cost for the 1 Bcm GPZ at Kashagan ($860 million capex) is very high at around $230/Mcm. Moreover, higher gas processing also means more sulfur extraction, and that brings storage requirements and marketing headaches, and necessitates greater attention to compliance with environmental regulations. To attract investment to gas development and production, the government of Kazakhstan has adopted amendments to the Tax Code, including a revised gas pricing formula for "new" gas (new projects or additional output from existing ones). However, incentives for new gas processing have not been incorporated into legislation or the Improved Model Contract.

Table 6.6 Kazakhstan's gas processing plants

Gas processing plants	Capacity (Bcm/y)	Utilization in 2021 (%)
Tengiz GPZ	13.0	100%
Zhanazhol GPZ	8.4	62%
Bolashak GPZ	6.3	84%
Chinarevskaya GTU	4.2	16%
KazGPZ	1.5	60%
Shagyrly GTU	1.3	73%
Amangeldy GPZ	0.7	49%
Akshabulak GTU	0.6	67%
Targabatay GPC	0.6	52%
Kozhasay GPC	0.4	100%
Alibekmola GTU	0.4	100%
Borankol GTU GPZ	0.4	10%
Severny Nurzhanov GPZ	0.2	100%
Karakuduk GPZ	0.1	26%
Arystanovskoe GTU	0.1	44%
Vostochny Makat GPZ	0.0	100%
EmirOil	0.0	87%
Balginbayev S. GPZ	0.0	100%
Kulzhan GTU	0.0	28%
Kashagan GPZ (QazaqGaz)	*1.0*	
Zhanaozen GPZ	*0.9*	
KPO GPZ	*4.0*	
Kashagan GPZ	*4.0*	

Notes: Italicized means planned GPZ.
Source: S&P Global, QazaqGaz.

39 In September 2023, NCOC began construction of a 15-km feeder pipe from its Bolashak facility.

40 The GPZ was initially scheduled to go into operation in the fourth quarter of 2023. QazaqGaz took over the project in June 2022 from the previous operator, GPC Investment LLP. In February 2023, QazaqGaz reported that a comprehensive audit discovered "critical shortcomings" in the project design that pushed the completion of the GPZ back to 2025. Initially the plant's capacity was planned to be 1.15 Bcm/y with dry gas output at 0.815 Bcm/y.

41 This doubles the amount of available raw gas processing capacity in Phase 2A compared to the agreement signed between the NCOC partners and QazaqGaz in December 2021, with the total amount of raw gas made available during phase 2A increasing from 3 Bcm/y to 5 Bcm/y, including the 1 Bcm/y Kashagan GPZ.

42 Although cost estimates have not been announced, prior estimates for a 2 Bcm/y GPZ at Kashagan were around $2.6 billion.

43 KMG announced that the tender for the construction of the Zhanaozen GPZ should be completed by the end of September 2023.

6.8 Gas transportation in Kazakhstan

Since independence, Kazakhstan has succeeded in creating a unified domestic gas system. This was mainly accomplished with the completion of the first string of the Beyneu-Bozoy-Shymkent (BBS) pipeline in 2015, together with the construction of additional loops and pipeline links, as well as installation of advanced compressor stations. Now all the main gas trunklines of Kazakhstan are connected into a single gas transportation system, including the Soyuz, Central Asia–Center (CAC), Bukhara-Urals, Tashkent-Bishkek-Almaty, and Gazli-Shymkent, as well as the BBS and CAGP pipelines (see Figure 6.15 Kazakhstan's gas sector (selected key elements) and Table 6.7 Kazakhstan's existing main gas pipelines as of 1 January 2023). The unified system allows Kazakhstan additional security and flexibility in gas operations, including: (1) less dependence on Uzbek gas for its southern regions, which has proved critical since 2018; (2) the possibility for large-volume gas exports to China, which has proved vital for QazaqGaz since 2017; and (3) provision of a gateway for the gasification of areas in central and northern Kazakhstan that previously lacked access to piped natural gas.

QazaqGaz is the national gas operator in Kazakhstan for gas exploration, production, transportation, and distribution. Through its subsidiaries, QazaqGaz operates gas pipelines totaling around 76,800 km, including 20,800 km of large-diameter pipelines with an annual throughput capacity of 260 Bcm of gas, and gas distribution networks totaling 65,686 km. The transportation system also includes 32 compressor stations with 319 gas pumping units (GPUs), and 248 gas distribution stations. QazaqGaz also serves as the state representative in major gas pipelines operated by joint ventures involving foreign partners.

Figure 6.15 Kazakhstan's gas sector (selected key elements)

Source: S&P Global Commodity Insights upstream E&P/midstream content (EDIN): 2009797.

Table 6.7 Kazakhstan's existing main gas pipelines as of 1 January 2023

	Estimated total pipeline length (km) on Kazakh territory	Estimated throughput capacity (Bcm/y)	Number of strings	Diameter (mm)
Central Asia–Center (CAC)*	3,961	42.7	5	1,020 1,220
Central Asia–China Gas Pipeline (CAGP)**	1,830	59.1	3	1,067
Soyuz	423	24.4	1	1,420
Kartaly-Rudny-Kostanay	156	1.6	1	820
Orenburg–Novopskov***	382	16.0	1	1,220
Bukhara–Urals****	1,447	26.0	2	1,016
Okarem–Beyneu	545	7.2	2	1,015
Beyneu–Bozoy–Shymkent	1,450	15.0	1	1,067
Akshabulak-Kyzylorda	123	0.4	1	325
Bukhara–Tashkent–Bishkek–Almaty (BGR–TBA)****	792	5.8	2	1,020
Makat–North Caucasus	371	22.0	1	1,420
Gazli–Shymkent*****	309	4.4	1	1,220
SaryArka (Phase I)	1,061	2.2	1	820

Notes: *Diameter of CAC's first string is 1,010 mm.
**CAGP's throughput capacity is 55 billion standard cubic meters (Bscm).
***Orenburg–Novopskov and Soyuz pipelines' combined throughput capacity is 40.4 Bcm.
****Bukhara-Urals contains two parallel lines, each 1,447 km in length. BGR-TBA also contains two parallel lines; one line is 792 km in length, the other 846 km.
*****Gazli-Shymkent capacity was previously about 11.5 Bcm/y, but now it is much lower due to lack of maintenance.
Source: S&P Global, QazaqGaz.

Intergas Central Asia (ICA), a specialized subsidiary of QazaqGaz, owns and operates nearly all of the national trunk gas transmission system and the three main underground storage facilities.[44] The trunk transmission system (20,800 km) carried 93.5 Bcm in 2022, about 10% less than the 103.6 Bcm transported in 2021. Transit gas accounted for the bulk (77%) of the transported flows, while deliveries to domestic consumers accounted for 18% of the total (see Table 6.8 Gas shipments through Kazakhstan's major trunk pipelines).

However, operation of the gas transportation infrastructure is constrained by a high degree of deterioration and resultant low throughput capacity. The core of Kazakhstan's national pipeline infrastructure dates from the Soviet period, with the average wear rate (share of assets needing replacement, having exceeded their designed retirement date) of many pipelines over 70%, according to ICA. The company intends to modernize the gas transmission system and has developed a plan that by 2030 will reduce this level of asset depreciation to 25%. The trilateral agreement to supply Uzbekistan with Russian gas via the Central Asia–Center (CAC) pipeline will necessitate upgrades as well. In 2022, ICA spent 141.4 billion tenge ($313 million) on new infrastructure, including construction of a gas pipeline and compressor station from the Kashagan GPZ to the Makat-North Caucasus gas pipeline and completing construction of the Zhetybay-Kuryk gas pipeline; ICA also spent 26.6 billion tenge ($50 million) on maintenance. At the time of this writing, QazaqGaz had eliminated 22,482 out of 47,912 pipeline defects revealed as a result of the trunk gas pipeline inspections carried out over a period of 5-7 years. QazaqGaz intends to continue this work of eliminating the remaining pipeline defects in accordance with the company's ongoing capital expenditure plans.

ICA operates some of the distribution pipeline networks that carry gas from trunk pipelines to end-consumers, while KTG Aimak, another subsidiary of QazaqGaz, is the entity that is mainly responsible for final gas deliveries to end-users. The expansion of Kazakhstan's local pipeline distribution networks has been proceeding for over a decade or more, but it has accelerated since 2017. Although most piped gas is still consumed in large population centers along the trunk pipeline routes, significant gasification efforts have added smaller cities, towns, and settlements, dramatically increasing gasification levels. Gasification levels across the country continue to increase. In 2022, about 107 settlements were gasified, bringing the overall gasification level for Kazakhstan to 59%. In 2023, government plans call for gasification of additional 56 rural settlements, bringing gas to an additional 166.6 thousand people and reaching the goal of 60% gasification.

44 The three underground storage facilities are the Bozoy UGS facility (4 Bcm capacity) in Aktobe Oblast; the Poltoratskoye UGS (0.35 Bcm capacity) in Turkestan Oblast; and the Akyrtobe UGS (0.3 Bcm capacity) in Zhambyl Oblast.

Table 6.8 Gas shipments through Kazakhstan's major trunk pipelines (Bcm/y)

	2015	2016	2017	2018	2019	2020	2021	2022
Total gas transportation via pipelines	**119.8**	**104.1**	**117.5**	**125.4**	**111.2**	**89.6**	**103.6**	**93.5**
ICA pipelines	**84.0**	**66.8**	**76.6**	**80.134**	**73.0**	**57.8**	**65.2**	**54.7**
Domestic deliveries	11.5	12.3	12.9	13.6	13.7	14.3	15.8	16.8
Export	12.7	13.3	16.7	18.9	19.1	12.7	8.5	4.9
International transit (ICA)	59.7	41.2	46.9	47.7	40.2	30.8	40.8	32.9
Russian transit (Russia-Russia)	53.1	37.0	41.4	43.9	30.7	25.7	30.8	29.1
Central Asian transit to Russia	6.6	4.3	5.5	3.8	8.9	3.8	9.0	2.3
Uzbek transit (Uzbek-Uzbek)	0.1	-	-	-	0.6	1.3	1.0	1.1
Russian gas to Kyrgystan							-	0.4
CAGP transit (total)	**35.9**	**37.3**	**40.9**	**45.3**	**38.3**	**31.9**	**38.5**	**38.9**

Source: S&P Global, ICA.

In 2023, the length of distribution pipelines in the country totaled over 59,181 km. KTG Aimak also reports that the length of gas distribution pipelines in urban and rural areas (inside the city-gate) has increased by almost 50% between 2017 and 2021, with about 8,555 km added since 2016. The largest distribution networks are in Almaty, Turkestan, Atyrau, and West Kazakhstan oblasts; the largest additions to gas pipeline networks inside the citygate in recent years were in Astana city and Almaty and Kostanay oblasts. KTG Aimak delivered 13.4 Bcm of gas through its distribution pipelines in 2021.

To facilitate the growth of gas consumption and to reach its gasification goals, QazaqGaz is undertaking a number of projects to upgrade, strengthen, and build out gas infrastructure (see Table 6.9 Kazakhstan's planned/proposed trunk gas pipelines):

- ***Kashagan connector to Makat–North Caucasus.*** Construction of a 17 km trunk pipeline from the Kashagan GPZ (planned for 2021-23) to provide an outlet for the processed gas coming from the new 1 Bcm/y plant by QazaqGaz. The pipeline will include a compressor station with potential capacity expansion from 1 Bcm/y to 4 Bcm/y.

- ***Looping on Makat–North Caucasus.*** A 130 km looping line to provide reliability of gas supply to the population and large industrial enterprises of Atyrau Oblast (especially to the special economic zone hosting the Atyrau petrochemical plants); expected timeline of the project is 2021-23, with capacity of the looping line at 7.5 Bcm/y; the key source of gas for the new looping line is expected to be the Tengiz GPZ via CAC.

- ***Second line of Beyneu-Bozoy-Shymkent pipeline (BBS-2).*** Construction of BBS-2 aims to maintain export potential and stable gas supply to the southern and central regions of the country; planned capacity of BBS-2 is 10 Bcm/y or more, with a tentatively planned construction completion date of 2027. BBS-2 is intended to supply large new commercial customers in southern and central Kazakhstan, including Almaty TETs-2, ERG, and ArcelorMittal. The pipeline is planned to be constructed by attracting private investment through investment incentives, including "take-or-pay" contract. In May 2023, at the first Central Asia-China Summit, QazaqGaz and CNPC signed a cooperation agreement that included the construction of BBS-2.

- ***Beyneu-Zhanaozen-2.*** Construction of the Beyneu-Zhanaozen-2 pipeline is a part of the Okarem-Beyneu trunk pipeline upgrade, intended to augment the existing section, allowing a more reliable gas supply to settlements in Mangystau Oblast, MAEK-Kazatomprom LLP's power station, and other large enterprises.[45] Aggregate pipeline capacity will increase from 3.1 Bcm/y to 8.9 Bcm/y. Beyneu-Zhanaozen-2 will be supplied with reverse flow gas (flowing from north to south) from CAC.

- ***Zhanaozen-Aktau.*** QazaqGaz plans major capital upgrades of the existing three strings of the Zhanaozen-Aktau pipeline. Additionally, construction of a fourth line for the Zhanaozen-Aktau segment, connecting to the Okarem-Beyneu trunk pipeline, is planned and will supply gas to Aktau, Kuryk, and other settlements. Aggregate capacity expansion is planned from 2.7 Bcm/y to 6.1 Bcm/y.

- ***Bukhara–Urals pipeline to Aktobe.*** Construction of a third spur from the Bukhara–Urals pipeline to Aktobe is intended to provide additional gas supply to meet rising demand in Aktobe city and nearby settlements. Construction is planned for 2022-23, with a pipeline capacity of 2.4 Bcm/y and an estimated capex of 43.4 billion tenge ($96 million). The first two spurs from the Bukhara-Urals pipeline to Aktobe are reported to be nearly worn out.

- ***Zhanazhol-Aktobe pipeline 2.*** Construction of a second string of the Zhanazhol-Aktobe pipeline is also being considered. To date, Aktobe is supplied with gas from two trunk gas pipelines—Zhanazhol-Aktobe (0.9 Bcm/y) and Bukhara-Urals (3.2 Bcm/y); Aktobe's city administration has long been eager to increase gas supply to the city and to alleviate concerns about supply from the aging Bukhara-Urals pipeline. Estimated capex for the Zhanazhol-Aktobe pipeline 2 is 120.3 billion tenge ($267 million).

In addition to the projects formally announced by QazaqGaz, discussions between Kazakhstan, Russia, and Uzbekistan regarding the creation a regional gas supply framework could lead to the expansion of existing Kazakh gas transportation capacity or even the construction of entirely new pipelines.

45 Kazakhstan's section of the Okarem–Beyneu (CAC-3) pipeline (commissioned in 1976) is one of the more worn-out gas pipelines according to QazaqGaz, with a wear rate greater than 75%. QazaqGaz plans major capital upgrades on this string of the pipeline system.

Table 6.9 Kazakhstan's planned/proposed trunk gas pipelines (as of 1 August 2023)

	Estimated total pipeline length (km) on Kazakh territory	Estimated throughput capacity (Bcm/y)	CAPEX (bln, KZT w/o VAT)	Expected commisioning or construction start-up date	Documents	Preliminary status
Aktobe-Bukhara–Ural third line	165	2.4	43.4	2023	Presentation of the Minister of Energy for the Majilis*	In process
Zhetybay-Kuryk, with AGRS-80 installation in Kuryk	85		22.9	2022	Kazakhstan's Comprehensive Plan for the Gas Industry**	Commissioned in 2022
Zhanazhol-Aktobe second line	244		120.3	2025	Presentation of the Minister of Energy for the Majilis*	Planned
Okarem-Beyneu, line 2	473				Annual report 2022 ICA	In process
Beyneu–Zhanaozen, line 2	308	5.8	160.8	2023	Kazakhstan's Comprehensive Plan for the Gas Industry**	In process
Zhanaozen-Aktau, line 4	428	4.5	27.5	2023	Presentation of the Minister of Energy for the Majilis*	In process
Beyneu–Bozoy–Shymkent, line 2	1,450	15.0	160.8	2026-2027	Kazakhstan's Comprehensive Plan for the Gas Industry**	Development of project documentation
Looping on Makat–North Caucasus	130	13.1	89.1	2023	Kazakhstan's Comprehensive Plan for the Gas Industry**	In process
Kashagan gas processing plant (GPZ)-Makat–North Caucasus	17	1.0	71.9	2023	Invest program ICA	In process
Almaty-Bayserke-Talgar, line 2	64.0	1.5		2023	Annual report 2022 ICA	Development of project documentation
SaryArka, Phase II and Phase III	483		188.5	n/a	Presentation of the Minister of Energy for the Majilis*	n/a
Barnaul-Rubtsovsk-Semey-Ust-Kamenogorsk-Pavlodar	679			n/a	Presentation of the Minister of Energy for the Majilis*	n/a
Kostanay-Astana-Pavlodar-Semey-Ust-Kamenogorsk				n/a	Presentation of the Minister of Energy***	n/a
Omsk-Pavlodar-Semey-Ust-Kamenogorsk				n/a	Presentation of the Minister of Energy***	n/a
Ishim-Petropavlosk-Kokshetau-Astana	644			n/a	Presentation of the Minister of Energy for the Majilis*	n/a

Notes: *Presentation of the Minister of Energy for the Majilis on the prospects for the development of the gas market, June 2022.
**Kazakhstan's Comprehensive Plan for the Development of the Gas Industry for 2022–2026.
***Presentation of the Minister of Energy about results of 2022 and plans for 2023.
Source: S&P Global, QazaqGaz, ICA.

6.8.1 Gas transit

Because of its geographic location, Kazakhstan is still an important transit country, with externally-sourced gas moving across Kazakh territory to third countries, including from Central Asia to Russia and China; from Russia to itself, and also to Kyrgyzstan; and from Uzbekistan to itself (moving across Kazakhstan to supply the Uzbek capital of Tashkent) (see Table 6.8).

Transit gas has always taken up the largest share of the gas moved through the country's trunk pipeline system. As a consequence, transit revenues are an important source of revenue for the national operator. For over a decade, transit volumes have been in the range of 78-95 Bcm/y. In 2022, an aggregate of 71.8 Bcm of gas transited Kazakhstan, a 10% decline compared to 2021. The decline is largely associated with the lower volume of Turkmen gas transit going to Russia.[46] In 2022, transit to China amounted to 38.9 Bcm or 54% of total transit; Russian gas transit accounted for 29.1 Bcm, or 41%; and Central Asian gas transit to Russia accounted for only 3% of the transit volumes, a marked difference from the years past, when this category accounted for about 50% of gas transited. Going forward, transit flows will remain the largest component of the total gas flowing in Kazakhstan's pipeline system, with the bulk being Central Asian transit volumes flowing eastward across Kazakhstan to China via the CAGP system. A new transit flow, of Russian gas south to Uzbekistan, is slated to begin later in 2023.

6.8.2 Gas supply dilemma for north-central and eastern Kazakhstan: Extension of SaryArka pipeline or Russian imported gas?

A key component of Kazakhstan's overall gasification strategy, and its efforts to reduce GHG emissions as part of its Intended Nationally Determined Contribution (INDC) to the 2015 Paris Climate Agreement, is to extend the natural gas transportation network to areas not presently able to access pipeline gas. Major unserved regions are located in north-central and eastern Kazakhstan. For gasification of these areas, the government is now considering three options for gas supply:

- **Domestic gas:** *Extending the SaryArka pipeline* from Astana to Kokshetau (phase 2) and then to Petropavlovsk (phase 3); this would involve a total capex of 185 billion tenge ($420 million); the pipeline length would be 483 km.
- **Imported Russian gas:** Russian gas could be brought in via one or more new pipelines:
  - *Ishim-Petropavlovsk-Kokshetau-Astana*, with total length of 644 km. This pipeline is the least ambitious of three proposed lines, supplying the capital and two major northern cities en route.
  - *Barnaul-Rubtsovsk-Semey-Oskemen* pipeline (with a spur to Pavlodar). The pipeline from Barnaul to East Kazakhstan and Pavlodar oblasts is expected to supply gas to ~2.1 million people, supporting 2.3 Bcm/y of consumption. The project will require construction of new infrastructure not only in Kazakhstan, but also in Russia. On Russian territory, the pipeline would have to be built from Barnaul to the Russia-Kazakh border; additional capacity would be needed to move more gas from Surgut to Novosibirsk and then to Barnaul, as the existing pipelines are currently operating at capacity.[47]
  - In February 2023, the Ministry of Energy of Kazakhstan announced that it is considering a third option for the gasification of the eastern part of Kazakhstan, which would include building a gas pipeline along the route *Kostanay-Astana-Pavlodar-Semey-Oskemen*, with the potential for Russian gas exports onward to China.
- **Hybrid (Russian-Kazakh) gas supply:** Kazakhstan's Energy Ministry also is considering an even more all-encompassing proposal for gasification of the north-central and eastern regions—*looping the main Saryarka gas pipeline together with a Russian gas pipeline* entering the region. Gazprom is currently conducting a pre-feasibility study of the project for the determination of the most economical route. The estimated cost of this project falls within the range of KZT 1.9-2 trillion ($4.4 billion), with the capacity to supply up to 40 Bcm/y.[48]

6.9 Domestic Gas Consumption

6.9.1 Kazakhstan's gasification program

In 2015 Kazakhstan embarked on a herculean 15-year gasification endeavor, designed to make piped natural gas available to millions of its people for the first time.[49] A key social project, it is a largely government-funded program aimed at raising domestic gas consumption, mainly by households. This is intended (in part) to help the country meet its emissions reduction goals under the Paris Climate Accord. The overall initiative reached its 2030 gasification goal of 56% nine years ahead of schedule, in 2021 (see Figure 6.16 Kazakhstan's gasification levels and 2030 targets). However, due to the sharp increase in domestic gas consumption in recent years and the need to modernize the gas transmission system to ensure

46 Turkmenistan's exports to Russia evidently declined from 10.6 Bcm in 2021 to 3.4 Bcm in 2022, or by 66.8%.

47 Construction of a small spur pipeline from Barnaul to Rebrikha (en route to Rubtsovsk) was completed in December 2021; Gazprom spent 2 billion rubles ($27.8 million) constructing the pipeline. Construction initially started on this pipeline in 2016, but was halted due to contractor issues; Gazprom resumed construction of the gas pipeline in mid-2020 after securing a new contractor "Tomskgazstroy." As part of Russian gasification program 2025-30, Gazprom plans to extend this pipeline from Rebrikha to Rubtsovsk via Aleysk.

48 The capacity figure is planned to accommodate Kazakh domestic demand as well as potential exports to China.

49 In late 2014, the Government of Kazakhstan approved the official "General Gasification Scheme of the Republic of Kazakhstan for 2015-30" ("Gasification Scheme"), codifying its long-held ambitions to expand the availability of piped gas in the country.

uninterrupted gas supply, the Ministry of Energy (together with QazaqGaz) updated the General Gasification Scheme in 2022. As a result, a new gasification goal was set at 65% for 2030. The Scheme reinforced Kazakhstan's commitment to further gasification of the residential sector and industry.[50] In 2022, the aggregate gasification level in Kazakhstan reached 59%.

The gasification program is funded mainly by national and local governments as well the national operator and other (private) sources. Over past five years, the gasification program has largely been focused on the construction of regional gasification facilities and low-pressure distribution pipelines. This activity is being 80-90% financed from the republican budget; meanwhile, funding for design and for the construction of the intra-settlement gas pipelines comes from the local (oblast-level) governments. In its 2022 annual report, QazaqGaz stated that it does not participate in the construction of small distribution pipelines inside the city-gate, but connects consumers to the larger gas network after being notified of their readiness.[51] The national company already has spent over 112 billion KZT (about $293 million) of its own funds on gasification during 2014-19.[52] QazaqGaz planned to spend an additional 14.3 billion tenge ($32 million) on regional gas transportation to facilitate gasification plans during 2021-23.

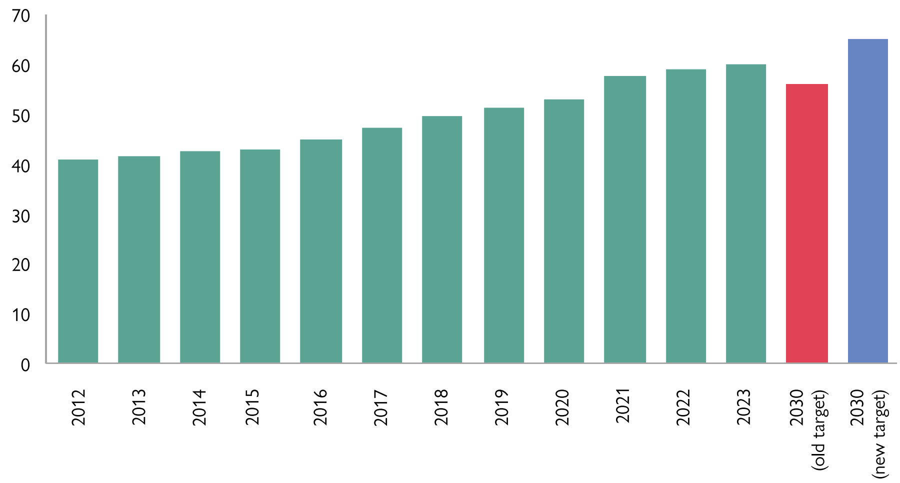
In 2022, consumer gas connection prices were unreasonably high. KTG Aimak's total price for consumer connection/gasification was 596,000 tenge versus 918,000 tenge in the competitive market. In order to incentivize competition and fair pricing in the market, during September-December 2022, KTG Aimak provided connection services in Astana city and Karaganda Oblast at prices close to the cost level. Based on 2022 results, KTG Aimak managed to carry out construction and installation works at about 566 residential buildings or 9% of the total number of newly gasified residential buildings (6,301; including 5,286 in Astana city and 1,015 in Karaganda Oblast). It is noteworthy that KTG Aimak carried out these construction and installation works at zero margin.

Gasification projects carried out by QazaqGaz subsidiary, KTG-Aimak, are financed through Samruk-Kazyna Trust, which is Samruk-Kazyna's foundation for financing social development projects. The Trust finances most of the gasification activities of Samruk-Kazyna companies. KTG-Aimak, in line with its responsibilities as a gas distributor, covers expenses associated with connecting consumers to its larger gas distribution system.[53]

The Ministry of Energy reported that in 2022 funds allocated for gasification projects from the republican budget reached 96.1 billion tenge ($213 million), doubling in size compared to 2021 and quintupling compared to 2018. The 2022 funds were spent on 142 gas projects, which were implemented across 107 rural settlements and provided gas to an estimated 285,000 people, according to the Ministry.[54] In 2023, gasification levels are set to reach 60% with budgetary allocations reaching 74 billion tenge ($164 million) to gasify 56 rural settlements, reaching 167,000 people.

The priority accorded to gasification projects aligns with the priorities of the Kazakh government as outlined in the ruling party's "Amanat" roadmap. The Amanat program calls for providing natural gas to residents of Astana, Karaganda, Kokshetau, Oskemen, Pavlodar, Petropavlovsk, and Semey cities by 2025 (step 247 of the program). The second relevant gasification goal (step 278) calls for ensuring gas access by 2025 to 246 villages with a total population of more than 900,000 people. By 2023 progress is significantly ahead of these gasification goals.

Figure 6.16 Kazakhstan's gasification levels and 2030 targets (%)



Source: S&P Global Commodity Insights.

50 The updated Gasification Scheme proposes to introduce digital technology along the gas delivery networks as well as at delivery points and gas metering devices.

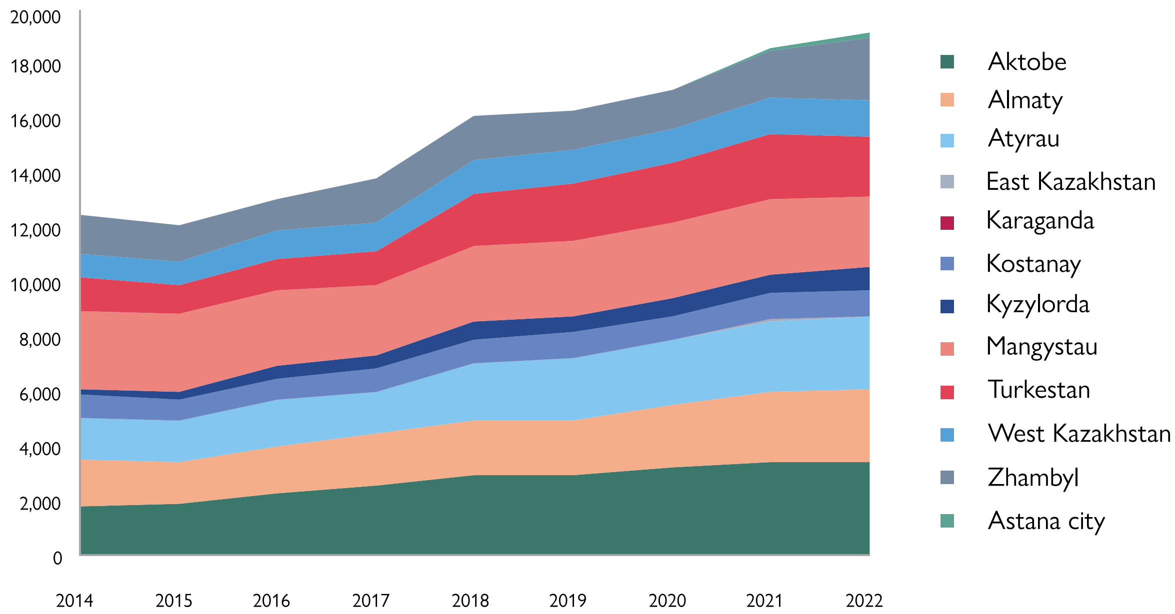
51 The Gasification Scheme clarifies that the decision on financing is made in accordance with the corporate rules for considering investment projects of the national operator. An estimated amount available for gasification financing is calculated based on the wholesale price of marketable gas, taking into account the national operator's profit margin of 5% during 2016-21 and 10% during 2022-30.

52 During 2010-20, QazaqGaz constructed more than 9,500 km of gas distribution networks.

53 In its 2022 annual report QazaqGaz revealed that its prices for connecting households directly to the gas network (at the domestic gas network level) were significantly lower than those of its private competitors. In 2023, KREM analyzed and deemed that KTG Aimak should not participate in construction and installation work for in-house gas networks after all. This is likely due to availability of other companies to perform this work and also to this activity not being KTG Aimak's primary competency or core responsibility.

54 During 2010-20, the state budget funded over 1,300 gasification projects and construction of more than 18,000 km of gas distribution networks across the country.

Figure 6.17 Natural gas consumption in Kazakhstan by oblast, 2014-22 (MMcm/y)



Source: S&P Global, Ministry of Energy RK.

6.9.2 Historical gas consumption

In 2022, end-of-pipe consumption (deliveries to consumers) reached 19.3 Bcm, a 4% increase over 2021 (see Table 6.4 and Figure 6.17 Natural gas consumption in Kazakhstan by oblast, 2014-22).[55] Gasification was an important driver behind the robust growth seen in end-user demand, with residential consumption rising by 8% year on year to 5.2 Bcm in 2022. Power sector gas demand rose sharply in 2021, by 22% to 11.5 Bcm, according to Kazakhstan's Statistical Bureau. Although demand in this sector declined by 7%, to 10.5 Bcm, in 2022, consumption was still quite high, particularly compared to historical numbers. In fact, the level of gas use in the power sector in 2022 was 14% higher than in 2020. Gas demand over the past two years was likely boosted by the need to deploy additional gas-fired power generation to meet the rising need for flexible generation.[56] Industrial gas demand (excluding power), however, declined by about 7% in 2022, reaching 3.7 Bcm in total.[57]

For the first half of 2023, end-of-pipe gas consumption rose by 3.9%. According to QazaqGaz, in the early months of 2023, Kazakhstan's peak gas demand reached an all-time high of 4.1 MMcm per hour (100 MMcm/d), which is 17.1% higher than in 2022. This was likely due to a colder than average winter.

The relative structure of gas consumption among the major sectors has remained broadly stable over time, even as the overall volume has increased. Of the total amount of gas sold to consumers in 2022 (19.2 Bcm), about 10.5 Bcm (55%) was used in the electric power sector to produce electricity and heat, about 1.9 Bcm (9.9%) was absorbed by industry, and 6.3 Bcm (33%) was used by a combination of residential and commercial-municipal consumers (the so-called "domestic" sector) (see Figure 6.18 Kazakhstan's natural gas consumption outlook by sector to 2050).

The use of gas in road transportation, including compressed natural gas (CNG) in municipal buses or light vehicles, or liquified natural gas (LNG) in trucking, amounted to only 3.5 MMcm in 2022. LNG use has effectively made no measurable progress in recent years.[58] Similarly, CNG is consumed only in niche transportation segments. As of the end of 2022, 21 CNG stations operated in Kazakhstan, of which 10 belong to QazaqGaz, 1 station in Almaty belongs to the municipal bus fleet, and the remaining 10 CNG stations belong to private enterprises. Southern Kazakhstan has the largest number of CNG stations in the country. The total number of vehicles running on CNG in Kazakhstan at the end of 2022 was 2,123, according to QazaqGaz. The volume of CNG supplied to refueling stations for own use by enterprises with vehicle fleets swelled from 157 m^3 in 2016 to 11.9 MMcm in 2017,

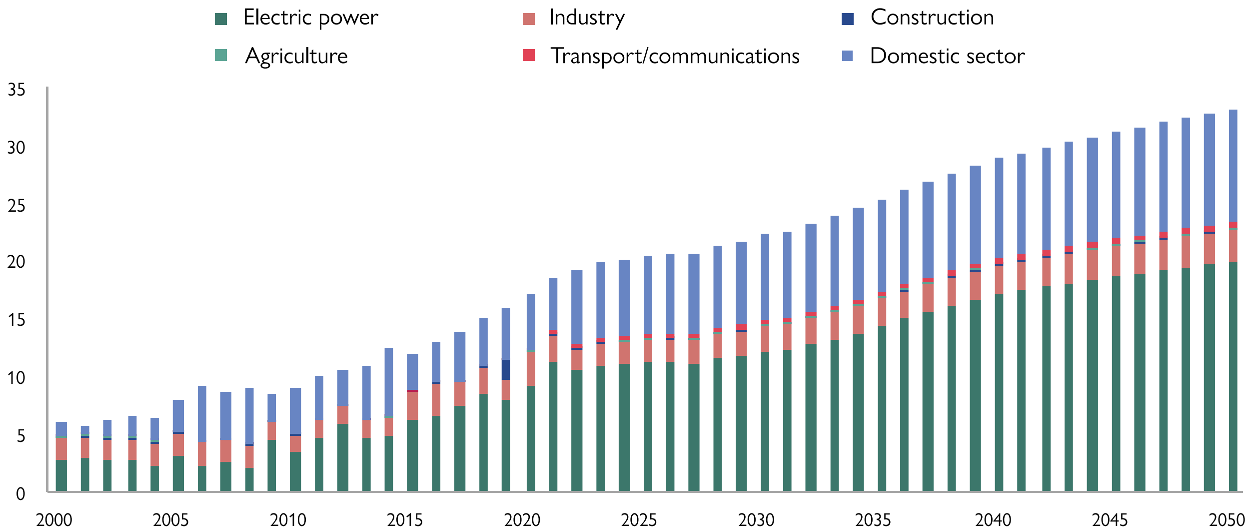
55 Other statistical sources (national energy balances) indicate that deliveries to consumers amounted to 18.3 Bcm in 2022. In 2022, we calculate total *apparent* consumption of natural gas in Kazakhstan (defined as commercial production minus exports plus imports) as 30.4 Bcm; other statistical sources indicate that this was 21.5 Bcm. The difference between apparent and end-of-pipe consumption represents other domestic disappearance, including field and processing losses, pipeline use, changes in stocks, etc.

56 In particular gas consumption in Zhambyl Oblast increased from 1.8 Bcm in 2021 to 2.3 Bcm in 2022, likely reflecting greater use at the Zhambyl power station, where electricity generation increased by 18.2% in 2021 and 70% in 2022.

57 This includes both at the end of the pipe (1.9 Bcm) and well as by the oil and gas industry at production sites. Within industry the largest consumers are ferrous metallurgy at 0.4 Bcm and chemicals (including feedstocks) at 0.6 Bcm in 2022; the oil and gas industry itself used 1.8 Bcm.

58 The first LNG mobile filling station was opened in Akmola Oblast in 2021 as a joint project between Kazakhstan, Russia, and China to support the New Silk Road initiative. There was also a mobile LNG station in Astana during EXPO-2017. The capital also has one LNG re-gasification station, with gas used for supplying heat to the Nazarbayev University.

Figure 6.18 Kazakhstan's natural gas consumption outlook by sector to 2050 (Bcm)



Notes: End-of-pipe consumption; transport excludes pipelines; domestic sector is residential-commercial-municipal.
Source: S&P Global, Kazakhstan's Bureau of National Statistics.

before declining to only 2.2 MMcm in 2020. Recorded retail sales of CNG amounted to 209.4 Mcm in 2016, peaked in 2018 at 1.3 MMcm, and fell to 891 Mcm in 2020. QazaqGaz reported that it supplied about 55 MMcm of CNG to refueling stations (in Almaty, Aktobe, and Rudnyy) in 2022, up from 42.2 MMcm in 2020.

The original set of measures to expand the use of natural gas as motor fuel was outlined in a resolution for 2019-22, approved by Government Decree No.797 dated 29 November 2018. However, plans to develop CNG/LNG infrastructure have progressed quite slowly given sufficient availability of traditional refined products on the market at attractive prices. In 2022, QazaqGaz reported that it initiated an extension to the 2018 resolution to increase natural gas a motor fuel to 2027. QazaqGaz set several goals it intends to achieve by 2027; these include:

- increasing CNG sales to 289 MMcm by 2027
- increasing the number of CNG vehicles to 3,830
- increasing the number of CNG stations to 35
- and increasing the number of LNG plants to 2.

The company states that it hopes to replace 218,000 tons of diesel fuel with natural gas and save about 31 billion tenge ($69 million) in fuel expenses.[59]

Concerns about the tightening gas balance and the need to rely on imports has raised energy security concerns among policymakers, as excessive dependence on gas imports may render important projects and infrastructure in the country vulnerable to supply disruption. Although an understandable concern, many gas-importing nations realize the importance of multiple sources for gas imports and usefulness of gas storage (see Chapter 2). Another initiative, spearheaded by the Ministry of Energy along with the Ministry of National Economy and QazaqGaz, focuses on a demand management approach and calls for adoption and implementation of a plan for Energy Efficiency and Rational Consumption of Commercial Gas (the Energy Efficiency for Gas Plan).[60] The plan proposes to implement energy efficiency measures such as a differentiated gas tariff for residential consumers, optimization of temperature standards during the heating season, switching to reserve fuels (coal), and others.

The Energy Efficiency for Gas Plan for 2023-25 proposes the flowing initiatives:

- Reduction in losses in the pipeline network
- Creation of a centralized gas metering system (digitalization of gas transmission and gas distribution systems)
- The introduction of commercial gas consumption allowances for households in each region, taking into account average weather conditions
- Increasing the overall efficiency of the fuel and energy complex.

The Ministry estimates that these measures could save 2.5 Bcm/y of gas without a negative impact on economic activity in Kazakhstan.

In terms of regional consumption, S&P Global identifies five regional gas-consuming "markets" in Kazakhstan, determined by such factors as sources of gas supply (indigenous production or imports) and the configuration of the national gas pipeline system. The five broadly identifiable regional gas "markets"

59 See QazaqGaz Annual Report 2022, p. 141.

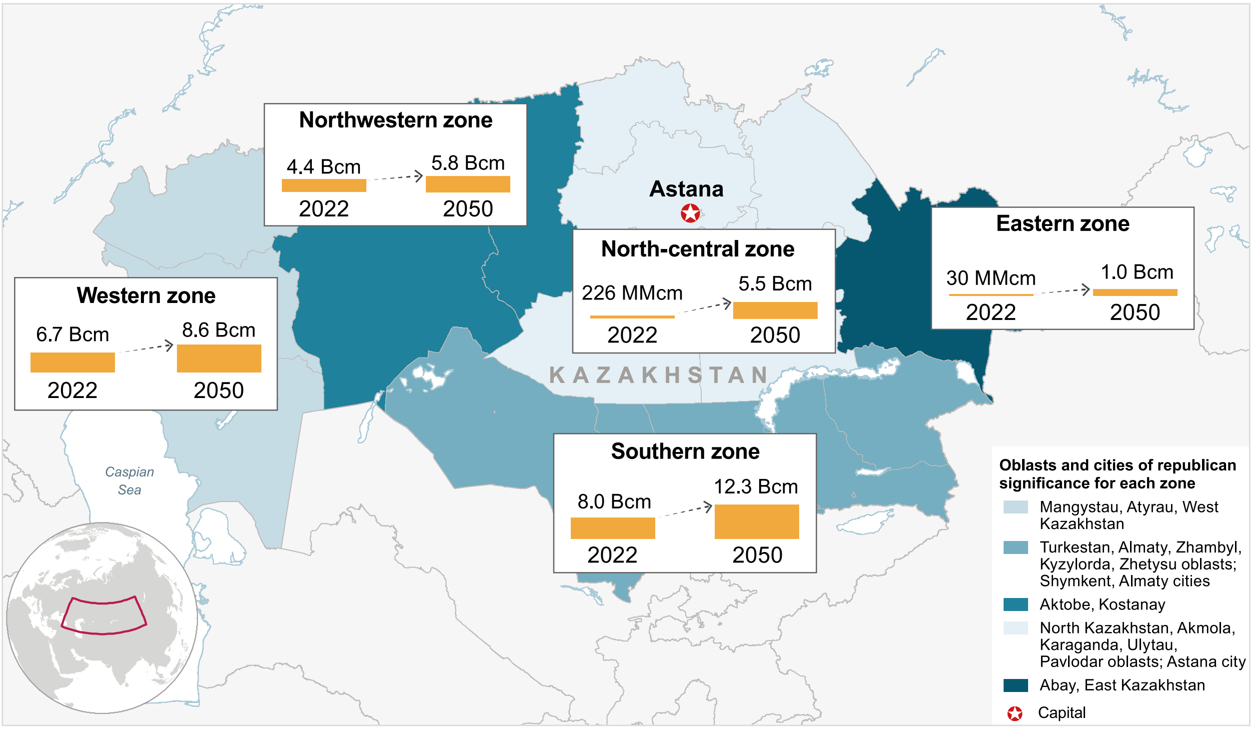
60 In March 2023, President Tokayev instructed the Government to develop an Energy Efficiency and Rational Consumption of Commercial Gas Plan.

or zones are (see Figure 6.19 Kazakhstan's domestic gas consumption (end-of-pipe) in 2022 and outlook to 2050 by consumption zone):

- The western zone, which includes Mangystau, Atyrau, and West Kazakhstan oblasts
- The southern zone, which includes Turkestan Oblast and Shymkent city, Almaty Oblast and Almaty city, and Zhambyl and Kyzylorda oblasts
- The northwestern zone, which includes Aktobe and Kostanay oblasts
- The north-central zone, a nascent gas-consuming area that is only now receiving piped gas for the first time, comprising Astana city, North Kazakhstan Oblast, Akmola Oblast, Pavlodar Oblast, and Karaganda Oblast
- The eastern zone, which encompasses East Kazakhstan and Abay oblasts, with current consumption currently organized around a small producing (Sarybulak) gas field that also traditionally exported gas to China.

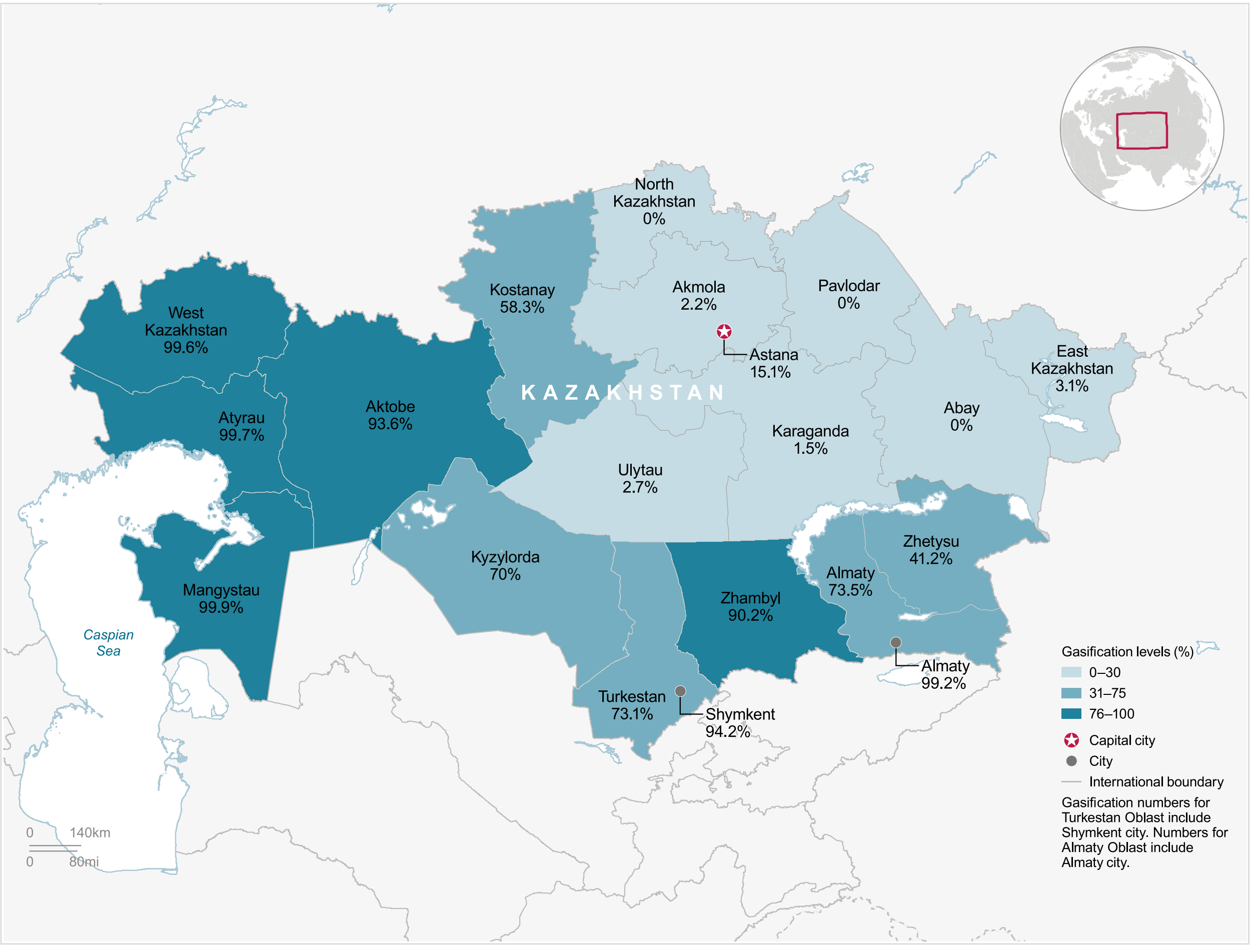
The western zone, where much of Kazakhstan's gas production is concentrated, historically had high gasification levels and consumption, with gas used in power generation, industry, and the residential-commercial segment. Gasification levels in western Kazakhstan rank among the highest in the country, reaching well over 90% of its population (see Figure 6.20 Gasification levels in Kazakhstan by oblast). Consumption in western Kazakhstan amounted to 6.7 Bcm in 2022, or 35% of national end-of-pipe consumption. Oblasts in southern Kazakhstan absorbed 8.0 Bcm in 2022 (45% of consumption), while the northwestern zone consumed about 4.4 Bcm of gas in 2022 (23% of consumption). In north-central Kazakhstan, gas demand is expanding with the ramp-up of the SaryArka pipeline. In 2022, gas consumption reached 0.226 Bcm compared to only 0.059 Bcm in 2021. Finally, gas consumption in East Kazakhstan Oblast was reported at 30 MMcm.

Figure 6.19 Kazakhstan's domestic gas consumption (end-of-pipe) in 2022 and outlook to 2050 by consumption zone



Source: S&P Global Commodity Insights: 2010716.

Figure 6.20 Gasification levels in Kazakhstan by oblast (2022)



Source: S&P Global Commodity Insights: 2009772.

6.9.3 Gas consumption outlook for Kazakhstan

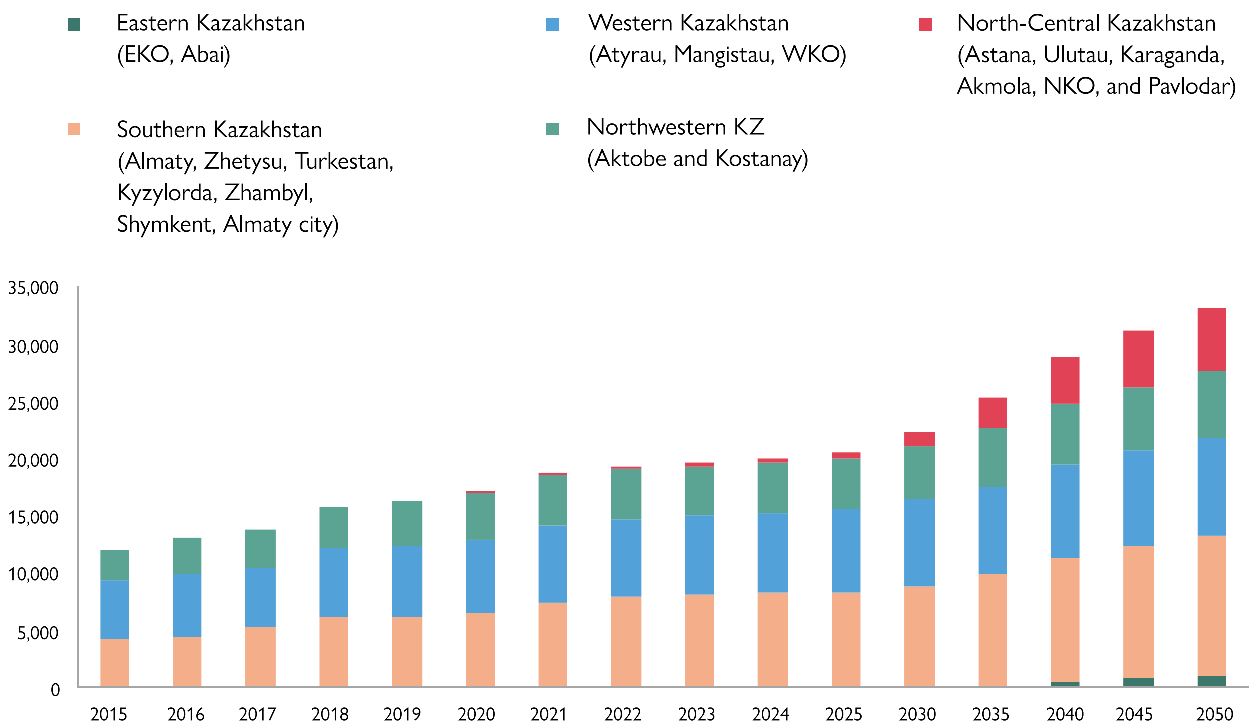
By 2050, S&P Global envisions national gas consumption (end-of-pipe deliveries) will reach around 33.2 Bcm (see Table 6.5, Figure 6.18, and Figure 6.21 Outlook for Kazakhstan's gas consumption by region). Gas use in the economy is expected to largely backfill for declining coal consumption rather than represent net additions to primary energy consumption. By 2050 the electric power sector is expected to consume almost 20 Bcm (60%) of gas demand. Between 2022 and 2030, gas demand in the segment increases by about 1.7 Bcm, but grows more rapidly post-2030, reaching 17.2 Bcm in 2040 and 19.9 Bcm in 2050.

In S&P Global's outlook for electric power generation, thermal generation (mainly from coal and gas, but also a bit of refined products) peaks in 2025 at 104.4 billion kWh and broadly declines to 87.4 billion kWh by 2050, with the share of thermal generation in the overall total decreasing from 89% in 2022 to 61% in 2050. The composition of thermal generation changes, with gas use increasing and coal decreasing. If in 2022, gas accounts for about 23% of thermal generation, then by 2050 it reaches over 51%. Meanwhile, the share of coal in thermal generation declines from 75% in 2022 to under 48% in 2050.

Gas consumption in the industrial sector, primarily in mining and manufacturing (including petrochemicals), is also likely to grow, albeit at a more modest pace. Policy support for coal to gas switching, which is currently focused on power generation, could emerge for the industrial sector in the future. Currently, many heavy industrial processes in Kazakhstan are still geared towards coal.

Residential-commercial gas consumption is expected to reach 9.8 Bcm in 2050, growing at a robust 1.6% per year on average during 2023-50. The growth is expected from new gasification projects as well as from higher usage by the current consumer base.

Figure 6.21 Outlook for Kazakhstan's gas consumption by region (MMcm)



Source: S&P Global Commodity Insights.

The use of gas in road transportation is likely to see some expansion across the country, although the segment has developed at a fairly languid pace in recent years.[61] By 2050, road transportation is expected to consume about 0.5 Bcm of gas per year. The updated gasification Scheme as well as the Gas Industry Development Plan to 2026 both mention the need for government subsidies to encourage development of natural gas as a motor fuel and as an alternative gasification approach to piped gasification via re-gasification terminals in East Kazakhstan and Abay oblasts. The idea of building re-gas stations to support regional gasification remains largely hypothetical in our outlook.

6.10 Expansion of Kazakhstan's Gas–Based Petrochemical Industry

6.10.1 Kazakhstan's gas-based feedstocks for gas-chemicals

Kazakhstan has access to ample gas-type feedstocks that can be utilized for petrochemical production. The country benefits from an abundant oil and gas resource base, and petrochemical producers in the country also have access to many other minerals — such as salts for chlor-alkali production — that are also important raw materials.

Despite the sizable presence of natural gas (methane) in the country, it is in relatively short supply commercially because of rising domestic needs for this clean fuel and the widespread use of gas reinjection to enhance oil recovery. Thus, it is difficult to foresee a substantial expansion of methane-based petrochemical production (e.g., ammonia, nitrogenous fertilizers, methanol) given the lack of commercial gas supply.

Kazakhstan does have an ample supply of low-cost NGLs such as ethane, propane, and butane that can be used as feedstocks for petrochemical development, however. This is the approach being taken in the development of the Atyrau integrated gas-chemical complex. But there are some ongoing initiatives in the methane chain that are being pursued, particularly by KazAzot, which has its own gas production and is looking at alternative gas monetization options other than sales to QazaqGaz as fuel (see below).

61 See Chapter 5.3.2. Use of natural gas in transportation and other potential uses for natural gas in *The National Energy Report 2017*.

6.10.1.1 Atyrau integrated gas-chemical complex, phase 1: Kazakhstan's world-class polypropylene plant starts up

The launch of a new polypropylene plant, located at Karabatan near Atyrau in western Kazakhstan, in November 2022 by Kazakhstan Petrochemical Industries Inc. (KPI) signals the start of a new era for Kazakhstan and its petrochemical industry.[62] The government has long promoted ambitious plans, dating back nearly two decades, to create a major gas-based petrochemical industry in the country, based on its feedstock-rich gas. The large new plant, with a capacity of 500,000 metric tons of polypropylene per year, is viewed only as the initial phase (Phase 1) of an overall scheme to build a large integrated petrochemical complex at the site (integrated gas-chemical complex [IGCC]). The second phase involves the launch of a large polyethylene plant. Plans also call for other related products, such as ethyl benzene, ethylene glycol, polyethylene terephthalate, and polyvinyl chloride, to be added eventually. The site has its own power plant, with a current capacity of 310 MW, with a planned expansion for an additional 160 MW.[63]

Groundbreaking for the polypropylene plant took place in 2009, as it was originally scheduled to start up in 2012–13. The project was repeatedly delayed by a number of factors, including changing project parameters and partners.[64] Serious construction, however, really only got underway in 2017 and was finally completed at the end of 2021, with the overall commissioning process beginning in early 2022. Propane was first delivered to the plant for processing in July 2022, when the plant was connected to the electricity grid. On 18 November 2022, the plant dispatched its initial shipment of 1,500 metric tons of polypropylene, which was for export. For 2022 as a whole, KPI shipped a total of 32,300 metric tons of polypropylene from the new plant.[65]

The new plant employs a propane dehydration (PDH) unit to produce propylene, using CB&I Lummus BV's catofin technology to convert propane into propylene. Lummus Technology LLC's Novolen gas-phase technology turns the propylene into polypropylene, producing up to 500,000 metric tons annually. The propane feedstock is supplied by TCO. It is Kazakhstan's largest oil producer by far, with a large associated gas output; it is also Kazakhstan's largest producer of LPGs (propane and butane).

TCO's total supply obligation is for up to 550,000 metric tons of propane annually. Propane deliveries occur under a contract signed in September 2021 between TCO and KPI. Another company, PTC Holding LLP, is the operator responsible for the transportation of propane to the plant as well as the dispatch of polypropylene from the plant. Currently, propane is delivered to the plant by rail. The propane is pumped from the arriving railcars to a tank storage farm that consists of four storage tanks. At full operation, this will involve the arrival of 10,500 railcars per year. KPI's contract with PTC Holding is through 2026; after 2027 the propane is slated to be supplied through a 205 km pipeline, extending from the Tengiz field to the Karabatan site.

The Karabatan site is set up as a special economic zone, known as the National Industrial Petrochemical Technopark (NIPT). Karabatan is located 33 km northeast of the city of Atyrau, with the actual site being 8-9 km north of the Karabatan rail station. The project developer and operator is KPI Inc., currently structured as a JV between KMG (49.5%), SKO (49.5%), and Firm Almex Plus LLP (1%).[66] The total capex for the polypropylene plant was $2.63 billion, including $1.87 billion for engineering, procurement, and construction (EPC). The main source of funding was a $2 billion loan from the China Development Bank, with the general contractor being China National Chemical Engineering Co. Ltd (CNCEC).

Currently, the plant is capable of producing 11 types of polypropylene, which so far have been primarily directed to the export market.[67] The plant is projected to eventually produce more than 65 different grades of polypropylene. Export shipments are carried out under a contract with Russia's PJSC SIBUR Holding, while domestic market sales are handled by KPI itself. When reaching full capacity, the distribution of international sales is planned to be China (170,000 t/y), Turkey (90,000 t/y), and European countries (50,000 t/y), with the remaining output going to other markets such as Russia, Belarus, Uzbekistan, and Southeast Asia.

Following several years of searching for another international partner for the project and several months of negotiations with SIBUR (PJSC SIBUR Holding), Russia's largest petrochemical company, in October 2021 KMG, SK, and SIBUR concluded a general agreement setting out the conditions for the entry of SIBUR into the project, subject to obtaining all regulatory approvals. In November 2022, KMG and SIBUR created a JV, Silleno LLP, that allows SIBUR to enter both Phase 1 (polypropylene) and Phase 2 (polyethylene), with a 40% stake in each project.

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62 KPI is a subsidiary of Samruk-Kazyna Ondeu LLP (SKO), previously known as United Chemical Company LLP (UCC). This state company was formed in 2009 specifically to implement petrochemical projects in the country. SKO is wholly owned by Kazakhstan's sovereign welfare fund, Samruk Kazyna (SK). On 3 February 2022, UCC re-registered and changed its name to SKO.

63 The construction of the CCGT power plant was completed in November 2019 by Karabatan Utility Solutions LLP (KUS). KUS operates in trust management for Samruk-Kazyna Construction JSC (joint-stock company). Its task is to build production infrastructure for the overall petrochemical complex, such as for electricity and high-pressure steam. The new CCGT plant consists of four gas turbines and two steam turbines; it is designed to operate on two types of fuel, either natural gas (supplied by the Makat-North Caucasus trunk pipeline) or propane-butane mix as a reserve option during periods when gas might not be available. Total capex for the plant was 111.2 billion tenge ($244 million).

64 One major hindrance was the withdrawal of LyondellBasell Industries NV as a shareholder in the project in 2010.

65 See the KMG Annual Report for 2022.

66 After initial plans were announced for the construction of the first two polymer plants, progress remained very slow. Because of the slow progress, management of construction was handed over to KMG in July 2018 under a trust management agreement with SK, which owns both SKO (then known as UCC) and KMG. In June 2022, upon completion of the construction phase, SK transferred a 49.5% stake in KPI to KMG as payment for the latter's services.

67 However, up to 20% of the plant's output (100,000 t/y) is slated to go to the domestic market. The Ministry of Energy estimates that current domestic consumption is about 50,000 metric tons, so it envisions very high growth in domestic consumption in the coming years.

6.10.1.2 Legacy petrochemical production in Kazakhstan

Kazakhstan does have several previously existing petrochemical facilities that cover the three principal petrochemical segments (olefins, aromatics, synthesis gas/inorganics). Some are holdovers from the Soviet period, and were often geared toward an entirely different economic reality (see Table 6.10 Kazakhstan's existing petrochemical plants and Figure 6.22 Kazakhstan's petrochemical projects). These include the following:

- Polypropylene by Neftekhim LTD at Pavlodar
- Aromatics at the Atyrau refinery
- Polystyrene at Aktau (Mangystau Oblast)
- Nitrogenous fertilizers and ammonia
- MTBE[68] production plant in Shymkent.

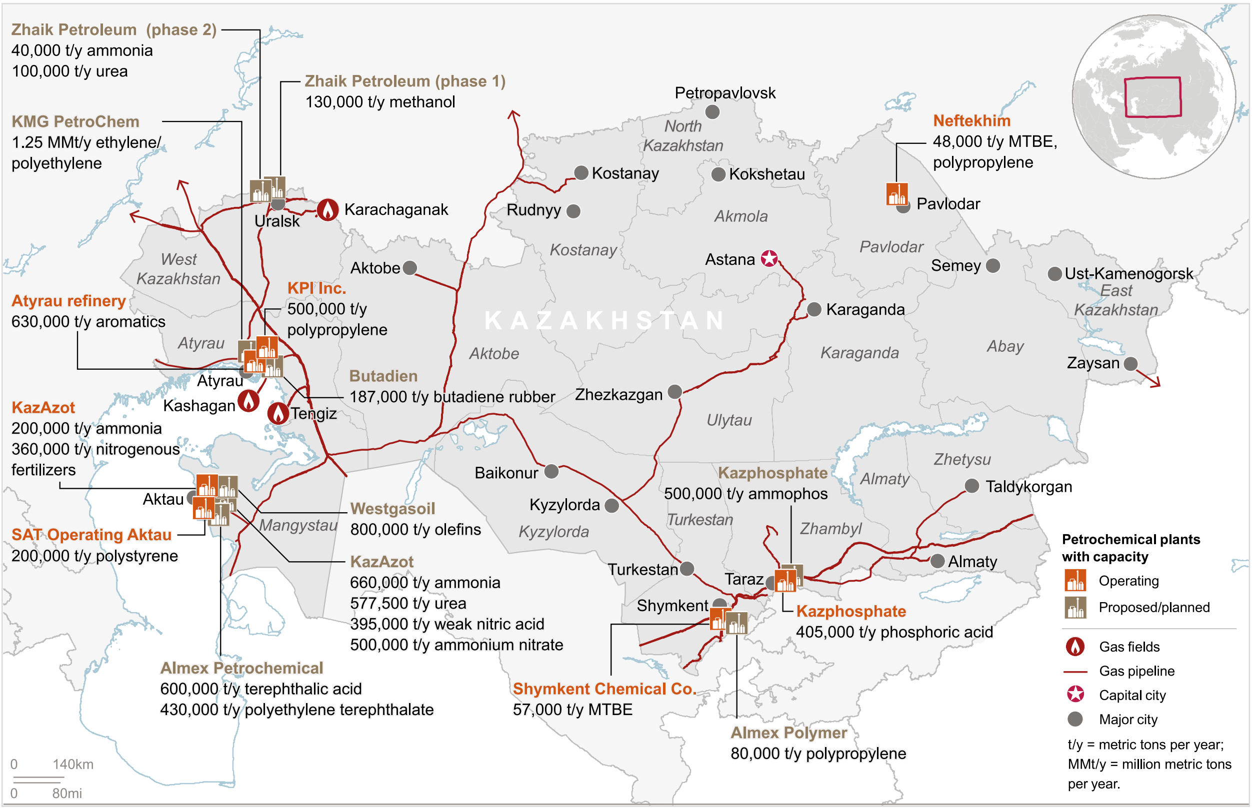
Table 6.10 Kazakhstan's existing petrochemical plants (as of year-end 2022)

Operator	Project type	Capacity (t/y)	Feedstock source	Location	Estimated project cost*	Commis-sioning year
KPI Inc.	polypropylene	500,000	550,000 t/y propane from TCO	Atyrau Oblast	$2.63 billion	2022
Neftekhim LTD	MTBE; polypropylene	48,000	refinery fluxes	Pavlodar Oblast	$37.29 million	2009
Atyrau refinery (KMG)	aromatics (benzene; paraxylene)	630,000	refinery fluxes	Atyrau Oblast	$1.33 billion	2016
SAT Operating Aktau	polystyrene	200,000	ethane	Aktau city	n/a	1980–81
KazAzot	ammonium nitrate	400,000	natural gas	Mangystau Oblast	n/a	1978
Kazphosphate	extraction phosphoric acid	405,000	natural gas	Zhambyl Oblast	$23.96 million	2016
Shymkent Chemical Company	MTBE	57,000	refinery fluxes	Shymkent city	$58.68 million	2021

Notes: *Converted from reported tenge costs as prevailing exchange rate of the period.
Sources: S&P Global Commodity Insights.

68 Methyl tert-butyl ether (MTBE).

Figure 6.22 Kazakhstan's petrochemical projects



Source: S&P Global Commodity Insights upstream E&P/midstream content (EDIN) 2009854.

6.10.2 Kazakhstan's general strategy for petrochemical development

The Atyrau integrated gas-chemical project at Karabatan is of considerable importance to Kazakhstan because it is hoped to be a key catalyst in the diversification of the hydrocarbon sector from a purely resource extraction position through more "valued-added" processing. In 2022, the chemical industry (together with rubber and resins) accounted for a mere 2.7% of the aggregate value of the country's industrial output, and therefore less than 1% of aggregate GDP. This is a very small share compared with other middle-income developing countries, especially for a major hydrocarbon producer such as Kazakhstan. Over recent decades, the chemical industry, which is research and capital intensive, has been one of the most dynamic industrial sectors globally, accounting for a rising share of overall value-added, often developing important links to other sectors of the economy, creating a high multiplier effect on overall economic growth.

The first official government program for the development of the petrochemical industry was for 2004–10. It envisioned the creation of an integrated cluster of world-class petrochemical industries with deep processing of hydrocarbon raw materials and the production of a wide range of competitive petrochemical products. This is when the National Industrial Petrochemical Technopark Special Economic Zone at Karabatan was created. A more recent program is the petrochemical program issued in October 2020, envisioning about $15 billion in capital outlays to build several regional clusters, not just in Atyrau, but also in Aktobe, Mangystau, West Kazakhstan, Turkestan, and Zhambyl oblasts. The medium-term target was to complete five major petroleum facilities by 2025.

In its most recent annual report on energy sector developments, the Ministry of Energy noted that Kazakhstan produced a total of 271,400 metric tons of petrochemicals in 2022, with a plan to produce 515,000 metric tons in 2023. Obviously, the launch and ramp-up of the new polypropylene plant will play a prominent role in the envisioned petrochemical sector expansion this year (see Table 6.11 Kazakhstan's planned petrochemical plants). Longer term, the volume of petrochemical products is expected to reach 1.126 MMt by 2024, 1.128 MMt by 2025, and 1.2 MMt by 2026.

Table 6.11 Kazakhstan's planned petrochemical plants (as of year-end 2022)

Operator/ company	Project type	Capacity (t/y)	Feedstock source	Location	Estimated project cost*	Commis-sioning year
KMG PetroChem	ethylene/ polyethylene	1.25 MMt/y	ethane from 9.1 Bcm/y Atyrau refinery gas separation unit	Atyrau Oblast	$7.6 billion	2028
Butadien	butadiene rubber	187,000 butadiene rubber	380,000 t/y of butane from TCO	Atyrau Oblast	$1 billion	2026
KazAzot	ammonia and urea	660,000 ammonia; 577,500 urea; 395,000 weak nitric acid; 500,000 ammonium nitrate	natural gas from KazAzot's Shagyrly-Shomyshty field	Mangystau Oblast	$1 billion	2022-2026
Kazphosphate	ammophos	500,000 ammophos	phosphate rock and ammonia	Zhambyl Oblast	$16 million	2023
Zhaik Petroleum	methanol	130,000 methanol	natural gas and carbon dioxide	West-Kazakhstan Oblast	$140 million	2024
Zhaik Petroleum	ammonia and urea	40,000 ammonia; 100,000 urea	natural gas	West-Kazakhstan Oblast	$200 million	2029
Westgasoil Pte	olefins	800,000 olefins	natural gas	Atyrau Oblast	$1.8 billion	2027
Almex Polymer	polypropylene	80,000 polypropylene	refinery fluxes	Shymkent city	$89.2 million	2025
Almex Petrochemical	terephthalic acid/ polyethylene terephthalate	600,000 terephthalic acid 430,000 polyethylene terephthalate	paraxylene from Atyrau refinery	Atyrau Oblast	$1 billion	2026

Notes: *Converted from reported tenge costs as prevailing exchange rate of the period.
Sources: S&P Global Commodity Insights.

6.10.2.1 Kazakhstan's planned petrochemical projects

Phase 2 development of the Atyrau integrated petrochemical complex: Polyethylene

The "second" phase of the Atyrau integrated gas-chemical complex involves the construction of a 1.25 MMt/y polyethylene plant at the Karabatan site, estimated to require $7.6 billion in capex.[69] Phase 2 of the "integrated complex" has proceeded in fits and starts for several years, with a number of changes in project partners along the way. KMG PetroChem LLP is the Kazakh entity charged with overall responsibility for Phase 2.[70] Currently, 100% of the shares of KMG PetroChem belong to KMG, after its recent official acquisition (1 December 2022) of the holding for a mere 2 tenge from two subsidiaries of Samruk-Kazyna: Samruk-Kazyna Ondeu (99.9%) and Polymer Production LLP (0.1%). But previously (since June 2019), 100% of KMG PetroChem's shares were already held in trust by KMG as the construction part of the project is executed. For a time, KMG PetroChem was a 50/50 JV between South Korea's LG Chem Ltd. and SKO (then known as UCC). In early 2015, LG Chem decided to withdraw from the company's share capital. Subsequently, a new partner was found to take over LG Chem's 50% stake, Austria-based Borealis AG.[71] Borealis also subsequently withdrew from the project in May 2020, citing market uncertainty driven by COVID-19. KMG PetroChem and the Ministry of Energy courted various investors, and in June 2021, it was announced that Russian petrochemical concern SIBUR would take a 40% stake in the project. In 2022, SIBUR entered into the polyethylene project with the creation of the Silleno JV (the project operator). This agreement also includes an arrangement for SIBUR to take a 40% stake in the Phase 1 project as well (polypropylene production). Later, in May 2023, Chinese company China Petroleum & Chemical Corporation (Sinopec) entered the project as a full partner on a par with SIBUR. Sinopec, as partner, will be in charge of sales of final product into the Chinese market.

Phase 2 development remains in the early construction stage, but the project has started to gain some momentum recently after languishing for several years. KMG signed an agreement to start design work with two companies. The first contract was signed on 11 December 2022, between KMG and Chevron Phillips Chemical Company LLC. The agreement provides development of design documentation for the polyethylene production plant using MarTECH® ADL technology and the

69 Initially, the project's cost was estimated at $6.5 billion, with the launch of operations in 2025.

70 KLPE changed its official name to KMG PetroChem in March 2023.

71 Abu Dhabi National Oil Company (ADNOC) owns 25% of Borealis AG, with the remaining 75% owed by the Austria-based OMV integrated oil and gas company.

Table 6.12 Kazakhstan's polyethylene balance (primary forms), 2015–22 (thousand metric tons)

	2015	2016	2017	2018	2019	2020	2021	2022
Production	0.0	0.0	0.0	0.0	0.1	2.4	3.4	4.4
Imports	101.3	108.0	125.3	155.5	170.5	182.5	175.4	227.3
Of which, from CIS	73.2	90.5	103.8	136.3	147.5	165.9	157.2	n/a
Of which, from other countries	28.2	17.6	21.5	19.2	23.0	16.5	18.1	n/a
Exports	1.7	3.5	1.9	1.0	7.8	1.8	2.7	2.7
Of which, to CIS	1.7	3.5	1.9	1.0	7.8	1.8	2.2	n/a
Of which, to other countries	0.0	0.0	0.0	0.0	0.0	0.0	0.5	n/a
Apparent consumption	99.6	104.5	123.4	154.5	162.8	183.0	176.1	229.0

Source: Kazakhstan's Bureau of National Statistics, S&P Global Commodity Insights.

provision of a corresponding license for the production of 625,000 metric tons of polyethylene per year. The second licensing agreement is for the second polymerization unit, also with an annual capacity of 625,000 metric tons. This was signed on 27 December 2022, between KMG and Univation Technologies LLC. The second agreement covers the provision of Univation's polyethylene polymerization catalyst systems, including catalysts for high-density polyethylene (HDPE) and linear low-density polyethylene (LLDPE).

The funding structure for the polyethylene project is still in flux, but is expected to be a combination of debt (loans) and the partner's own funds. The final products are planned to be sold both on the domestic market and for export, including to China, Turkey, the Commonwealth of Independent States (CIS), and European countries. Estimated domestic polyethylene market demand was about 160,000-180,000 t/y but increased to 229,000 metric tons in 2022, while domestic production is negligible (see Table 6.12 Kazakhstan's polyethylene balance (primary forms), 2015–22).

In addition to two polymerization lines, Phase 2 calls for the construction of a $1 billion, 9 Bcm/y gas separation unit (GSU) that would extract 1.5-1.7 MMt/y of ethane and 370,000 metric tons of propane/butane mix (comprising primarily of propane). This gas is to be sourced from the Tengiz field. The commercial arrangements between TCO and KMG PetroChem for gas supply date back to March 2008 when a contract was signed. The GSU would process up to 9.1 Bcm/y and return up to 7.8 Bcm/y of methane to TCO. The extracted ethane and propane/butane mix would feed into a new pyrolysis unit (steam cracker) to produce ethylene that would also be built as part of Phase 2 construction. For the GSU, it is planned to use two licensed installations of Honeywell UOP Inc. (US) technology: one for ethane extraction and another for propane purification. Early in 2021, KMG and Japanese company JGC Holdings Corporation signed an engineering and design contract for the GSU. In March 2023, KMG announced that the GSU would be financed with borrowed money, raised through a bond issued by the Kazakhstan National Fund.[72]

KMG PetroChem is apparently expecting to start front-end engineering and design (FEED) for the project in 2023, aiming to commission the project in 2028. However, several issues remain outstanding. First, while discussions between TCO and KMG PetroChem have continued, and the two parties have signed an agreement on the basic conditions for the design of a GSU, fundamental questions over gas pricing and procurement arrangements have yet to be fully resolved. Nonetheless, TCO and KMG PetroChem continue to work together on formulating the technical project documents.

Phase 2 will likely continue to gain momentum, especially after commissioning of Phase 1 and the imminent launch of TCO's Future Growth Project – Wellhead Pressure Management Project (FGP-WPMP) later in 2023. The operation of Phase 1 provides the essential "proof of concept" for future petrochemicals expansion in Kazakhstan.[73]

Butadiene at Atyrau

Another petrochemical project for which development is fairly well advanced is butadiene production. This is also based in the Karabatan Technopark, but involves an entirely different production chain. This project is being developed by Russia's PJSC Tatneft (holding a 75% stake) initially together with KMG, and later with Samruk-Kazyna (25%).[74] The planned capacity of the plant is 180,000 t/y of butadiene rubber. The preliminary cost of the project is estimated at $916 million, with an expected completion date of 2026. The feedstock, 380,000 t/y of butane, is planned to come from TCO.[75] The final product — butadiene — is planned to be used to produce tires at the new KamaTyresKZ LLP tire plant in Karaganda Oblast, and the marketing plan also includes some exports to markets including Europe, Russia, China, and Turkey. Construction and installation work was already well underway at the end of 2022.[76]

Technology for the project includes the iC4 CATOFIN®, CATADIENE®, CDMtbe®, and BASF SE's butadiene production

72 The National Fund of the Republic of Kazakhstan, established in 2000, is the sovereign wealth (oil) fund.

73 Transportation costs for the final product remain a major stumbling block for overall project economics and netbacks. Although low-cost NGLs theoretically make feedstock costs in the country fairly attractive, the logistical costs of moving product to a demand center can absorb a significant part of the revenue generated from product sales.

74 Samruk-Kazyna replaced KMG in this project in June 2023.

75 In November 2022, TCO and the project company, Butadien LLP, signed an agreement on the sale and purchase of butane.

76 KamaTyresKZ is a JV between Tatneft and AllurTyres LLP.

technology of US company Lummus Technology.[77] The license includes technology and basic engineering rights for four process units. In addition to the license, Butadien will have access to the portfolio of life-cycle services of Lummus Technology during the implementation and operational stages of this project.

KazAzot's ammonia-urea complex in Mangystau Oblast

Another of Kazakhstan's planned petrochemical developments is the construction of a new ammonia and urea (carbamide) complex. In January 2023, KazAzot Prime LLP (a subsidiary of KazAzot JSC that was created in December 2022) signed a contract for the design and construction of the complex with the Spanish engineering company Técnicas Reunidas SA. The new complex is planned to be built in the Aktau Seaport Special Economic Zone (Mangystau Oblast). Estimated capex of the project is $1 billion. The new complex is planned to produce about 1.5 MMt/y in aggregate, including 660,000 t/y of ammonia, 577,500 t/y of urea, 395,000 t/y of weak nitric acid, and 500,000 t/y of ammonium nitrate.

The project will use methane (natural gas) as the feedstock, supplied from KazAzot's own production. Its main field is Shagyrly-Shomyshty, in Mangystau Oblast. The field produced 783 MMcm in 2021 and 800 MMcm in 2022.[78] The company also owns the license to the Kosbulak field, which is still under exploration. So clearly, KazAzot is seeking an alternative monetization route for its natural gas other than selling it as fuel to QazaqGaz.

In 2023, the Ministry of Agriculture of Kazakhstan expects domestic demand for urea to be about 703,000 metric tons (versus 604,000 metric tons in 2021), reaching about 900,000 t/y by 2028. Hence, by 2028, when the new complex is expected to reach full capacity, KazAzot is expected to be able to fully cover Kazakhstan's domestic market demand.

Methanol production in West Kazakhstan Oblast

In 2022, Zhaik Petroleum Ltd. launched construction of a methanol plant (Phase 1) in West Kazakhstan Oblast. The company signed an EPC contract with CITIC Construction Co. Ltd. and China Huanqiu Contracting & Engineering (Shanghai) Co., Ltd. Total capacity is planned to be 130,000 t/y of methanol, with an estimated capex of $140 million. The commissioning date is reported as 2024. Phase 2 of the project will include production of ammonia and urea, with an estimated capex of $200 million. The expected commissioning date of Phase 2 is 2029. Not to be confused with upstream producer Zhaikmunai LLP, Zhaik Petroleum Ltd LLP does not have its own gas sources, so it remains to be seen if this project can be successfully realized given the shortage of commercial gas.

Methanol and olefin production in Atyrau Oblast

This proposed project consists of two stages: (1) methanol production from natural gas; (2) production of propylene and ethylene from methanol. This is a rather roundabout process, especially for a country that is long on NGLs and short on methane. Initially, the Kazakhstan Project Preparation Fund LLP (KPPF), Westgasoil PTE LTD (Singapore), and Haldor Topsoe GmbH (Germany) signed a memorandum of understanding for construction of this facility in the SEZ Aktau Seaport Special Economic Zone (Mangystau Oblast) rather than in Atyrau Oblast. Groundbreaking for this facility reportedly began in 2019, with commissioning planned for 2023–24. But now the beginning of construction of the facilities has been postponed to 2027.[79]

Polypropylene production in Shymkent city

A new planned polypropylene project planned to be built by Almex Polymer LLP has a capacity of 80,000 t/y, with an expected commissioning date of 2025. The project is considered to be phase 2 of the Shymkent Chemical Company[80] MTBE project commissioned in 2021. The plant will be located in the Ontustik special economic zone in Shymkent city. Feedstock is planned to be Shymkent refinery fluxes. Total expected cost of the project is $89.2 million.

Terephthalic acid and polyethylene terephthalate in Atyrau Oblast

The expected capacity of this project will be 600,000 t/y of terephthalic acid and 430,000 t/y of polyethylene terephthalate. The main feedstock will be benzene and paraxylene from the Atyrau refinery.

This project is being developed by Almex Petrochemical LLP. Total estimated cost of the project is $1 billion. Earlier, in 2017, it was announced that some project financing would be forthcoming from the Development Bank of Kazakhstan (DBK), but the project no longer appears on the list of projects applying for DBK funding in 2022. The feasibility study for the project has been completed; construction of the plant is expected to begin in 2023–24, with commissioning in 2026.

6.10.3 Export issues and logistics for petrochemicals in western Kazakhstan

As a landlocked country in the center of the Eurasian continent, one of the key factors to consider for an export-oriented petrochemical plant in Kazakhstan is the logistics, including costs and routes to market. Shipment of containerized polymer pellets, often in bags, is one of the most cost-effective methods of exporting petrochemicals from landlocked and remote areas.

77 Lummus Technology is the exclusive supplier for the butadiene CATADIENE technology, while the CATADIENE® and CATOFIN® technologies utilize Clariant AG's state-of-the-art catalyst.

78 Approximately 1,142,000 cubic meters of gas is required to produce one metric ton of ammonia, so KazAzot's current level of gas production can be used to produce about 700,000 t/y of ammonia.

79 In March 2022, Qazaqstan Investment Corporation JSC (formerly Kazyna Capital Management) announced a company reorganization of this project, joining with KPPF and another company, QazTech Ventures JSC.

80 Shymkent Chemical Company is a part of ALMEX Holding Group JSC.

Key export routes from western Kazakhstan include

- Overland to Aktau, Kazakhstan's Caspian port, and then by container ship to Baku, and from there by rail or road to one of the Georgian Black Sea ports (Poti, Batumi, or Kulevi) for exports to international markets
- Rail across Russia to the Baltic ports of Hamina/Kotka in Finland and then to international markets
- Rail to the Russian Black Sea port of Novorossiysk (or neighboring Taman), and from there to international markets
- Rail overland directly to China, which in addition to the long distance across Kazakhstan, also would incur significant transportation distances (and costs) within China to reach coastal consuming locations

Another alternative is direct ship access from the Caspian Sea. This route involves using the Volga-Don Canal to connect between the Caspian Sea and the Black Sea. This route is limited by size of ship (because of draft and width restrictions for ships of about 5,000 deadweight tons [dwt]), and seasonally, as this route is closed during the winter.

Access to markets such as India and Southeast Asia could be served by a southerly overland rail route through Turkmenistan and Iran to Bandar Abbas on the Persian Gulf. New rail infrastructure is being developed for this route; however, it is not a route used by large volumes of freight traffic.

Despite these sizable transportation costs, KMG and other petrochemical producers could very well compete in these key markets, especially in polymers such as polyethylene and polypropylene. However, this appears more uncertain for methanol, as it is a lower-value primary petrochemical shipped in liquid form. A key factor in determining the economics of these projects is prices for these petrochemical products in the destination markets. Given the current national balances for polypropylene and polyethylene, only some of the output from the new plants can be absorbed domestically; most of their output will have to be exported, rather than consumed domestically.

6.11 Natural Gas Trade: Historical and Outlook

6.11.1 Kazakhstan's gas exports

Kazakhstan's statistics on natural gas trade come from several official sources that nonetheless conflict with each other, given different methodologies. According to the Ministry of Energy, in 2022, Kazakhstan's exported 4.6 Bcm of natural gas, 36% lower than in 2021.[81] At the same time, Kazakhstan's Statistical Agency reported gas exports at 6.7 Bcm. S&P Global estimates operational (physical flows) gas exports were 13 Bcm in 2022, where 5.1 Bcm was exported to China and 7.9 Bcm went to Russia (see Table 6.4 and Table 6.13 Kazakhstan's natural gas exports and imports by destination 2015-22).

The difference in reporting in large part stems from what is included in the exports, with the main reason being the varying treatment of gas volumes sent to Russia. Mostly this gas is via the KPO-KRG[82] swap arrangement, where KPO gas is sent to Orenburg GPZ and then processed gas is mostly returned to Kazakhstan for domestic consumption.[83] In this respect, Kazakhstan's imports of KRG gas under the swap volumes, and by extension, KPO's commercial gas output, are integral to Kazakhstan's overall gas balance.[84] So, the Ministry of Energy and QazaqGaz several years ago began excluding the volumes of swap gas from the export figures and only report gas exports to China, whereas the Statistical Agency accounts for some of the gas that physically went to Russia.[85]

In addition to KPO, small volumes of Kazakh gas (from TCO) historically have been transported northward to Russia via the CAC and Soyuz pipelines. In the past, TCO gas exports ranged around 2-3 Bcm; they amounted to 3.7 Bcm in 2019, 2.5 Bcm in 2020, and 1 Bcm in 2021.[86] However, given the growing tightness if the overall gas balance, QazaqGaz reached an agreement with TCO whereby most of its gas is now diverted to the domestic market (~2 Bcm in 2022). Reported TCO exports in 2022 were only 0.2 Bcm. The agreement to sell gas to QazaqGaz is to continue for 2023 as well.

Exports to China plummeted in 2022 by 21%, according to S&P Global estimates. Several factors created a perfect storm for this decline, especially during the winter of 2022-23. Lower domestic gas production, lower imports, a 2.4 Bcm reduction in gas output at the Orenburg GPZ due to decreased ability of that plant to accept gas, breakdowns at the Kashagan and Tengiz gas processing plants, as well as higher gas consumption (helped by extremely low temperatures) squeezed exports, which forced Kazakhstan to cut exports to China for three months, even though gas exports are extremely important for QazaqGaz's financial stability.[87] Kazakhstan exported less gas to China in every month in 2022 than in 2021, except in August and September. China Customs data shows that Kazakh gas imports were significantly reduced between November 2022 and March 2023, with an estimated import volume of less than 0.5 Bcm during those five months, representing an 80% year-over-year decrease for the period. The onset of curtailed gas exports in November 2022 prompted China's Premier Li Keqiang to appeal to the Kazakh Prime Minister Alikhan Smailov to adhere to gas supply contracts and increase deliveries during the winter months.

81 According to QazaqGaz, total exports amounted to 4.9 Bcm, of which 4.33 Bcm were "centralized" QazaqGaz exports.

82 KazRosGas (KRG) is a joint venture between KMG and Russia's Gazprom formed in 2007. In June 2015, KPO and KRG extended their gas trading deal through 2038, securing an outlet for KPO's gas production through the end of the PSA.

83 Gas exports from Karachaganak to Russia are conducted under a special arrangement with Gazprom. Nearly all of Karachaganak's raw (high-sulfur) gas output (that is not reinjected) is sent across the border to Russia for processing at the Orenburg GPZ under a long-term agreement, with KRG playing a key intermediary role.

84 In 2022, KRG exported 0.37 Bcm of gas compared to 1.5 Bcm in 2021.

85 Kazakhstan's customs statistics indicate a broader list of export destinations for Kazakh gas, including small volumes to Ukraine and Turkey in 2022. These data reflect customs declarations, rather than physical (or contracted) flows reported by QazaqGaz.

86 See ICA Annual Report 2020 and 2022.

87 ICA reports that lower availability of gas for exports from the Zhanazhol, Amangeldy, and Kashagan fields in 2022 contributed to the decline in gas exports to China.

Table 6.13 Kazakhstan's natural gas exports and imports by destination 2015-22 (Bcm/y)

	2015	2016	2017	2018	2019	2020	2021	2022
Pipeline								
Karachaganak-Orenburg	9.6	9.6	9.6	10.3	9.9	9.9	9.0	9.0
Turkmenistan-Kazakhstan-China (CAGP+East Kazakhstan)	0.6	0.5	0.6	5.2	7.4	7.4	6.4	5.1
Total exports (customs data)	**21.5**	**21.6**	**25.6**	**26.5**	**25.6**	**19.8**	**16.0**	**12.9**
Total exports (operational data)	**10.9**	**12.8**	**16.8**	**19.4**	**18.8**	**11.9**	**8.5**	**4.9**
Total exports (sum of individual countries)	**13.3**	**12.8**	**16.8**	**19.1**	**19.4**	**16.7**	**14.8**	**13.0**
CIS countries	**12.7**	**12.4**	**16.2**	**13.8**	**11.9**	**9.4**	**8.2**	**7.9**
Russia*	12.6	12.4	14.7	12.3	11.3	9.0	8.2	7.9
Uzbekistan			1.5	1.3	0.4	0.1	0.0	0.0
Kyrgyzstan	0.1	-	-	0.3	0.3	0.3	0.2	0.0
Non-CIS countries	**0.6**	**0.5**	**0.6**	**5.2**	**7.4**	**7.4**	**6.4**	**5.1**
China**	0.6	0.5	0.6	5.2	7.4	7.4	6.4	5.1
Total imports (customs data)	**5.8**	**6.9**	**6.3**	**14.6**	**15.8**	**12.4**	**7.8**	**7.4**
Total imports (operational data)	**3.2**	**4.9**	**5.0**	**6.0**	**7.1**	**3.1**	**2.3**	**1.3**
Total imports (sum of individual countries)	**4.9**	**5.8**	**5.1**	**5.7**	**8.8**	**4.3**	**9.3**	**7.4**
Russia	1.7	2.9	3.0	3.2	5.1	3.4	9.3	7.0
Turkmenistan	0.3	1.3	0.3	0.0	0.0	0.1	0.0	0.4
Uzbekistan	2.9	1.7	1.8	2.5	3.7	0.8	0.0	0.0
Net exports	**8.5**	**7.0**	**11.8**	**13.4**	**10.6**	**12.4**	**5.4**	**5.6**

Notes: Data for Kazakhstan's exports to Russia from 2011 are taken from Russia's reported receipts of Kazakh gas; total exports are taken from Kazakh national statistics, creating an export discrepancy.
*Includes all of CIS export volumes handled by Gazpromexport.
**Kazakh volumes injected into CAGP pipeline in 2017; main export flows through CAGP were augmented with small volumes from East Kazakhstan Oblast until 2021.
Source: S&P Global Commodity Insights.

While Kazakhstan is still a net gas exporter, it is facing the threat of an actual natural gas shortage: its gasification program is driving up consumption while commercial gas production remains essentially flat. Gas balance tightness in Kazakhstan has been developing over many years, but it can be remedied with policy changes.

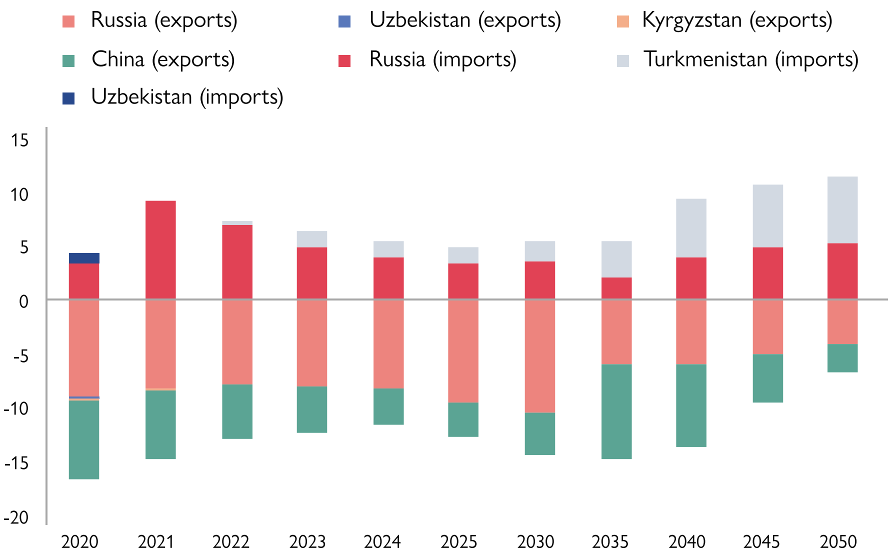
During 2022, there were a lot of discussions about "imminent" gas shortages in the country. Kazakhstan's energy minister announced on 8 June 2022 that the country would halt gas exports by 2025 to focus on the domestic market, even as oil production curbs also reduced associated gas production. In February 2023, QazaqGaz announced that gas exports to China will likely be halted during the 2023-24 heating season, to avoid shortages in the domestic market.

Nonetheless, during the "China–Central Asia Summit" in Xian (People's Republic of China) on 18–19 May 2023, as part of the cooperation agreement, QazaqGaz and CNPC pledged to sign a new natural gas purchase and sales agreement. In July 2023, QazaqGaz reported that it is negotiating a new gas export contract with China.

During the first half of 2023, Kazakhstan exported around 1.8 Bcm of gas, which is 26% less than during January-June of 2022. In 2023, QazaqGaz secured higher gas imports and will likely see higher output numbers, but the challenge of managing the national gas balance remain. Clearly any kind of unanticipated event, like a spate of extreme cold weather, could endanger exports in the winter months.

Longer-term, Kazakhstan will likely continue to send (relatively small) volumes of gas to China, possibly with seasonal wintertime reductions or even interruptions. Our base-case scenario is that domestic gas market reforms (price increases and improved E&P terms) and policy changes (construction of GPZs and additional imports) will likely result in rebalancing of the gas balance and a rebound in Kazakhstan's gas exports in the late 2020s. In the base case, Kazakhstan's exports to China decline from 5.1 Bcm in 2022 to 3.2 Bcm in 2025 but expand to 3.9 Bcm in 2030 and 7.6 Bcm in 2040. Russia remains a major "export" destination (for processing Karachaganak gas) over the output period as well. S&P Global's base case projects Kazakhstan's overall operational exports by 2050 to decline by 48% relative to the 2022 level, to about 6.7 Bcm (see Figure 6.23 Kazakhstan's natural gas exports and imports by destination: S&P Global base-case outlook to 2050).

Figure 6.23 Kazakhstan's natural gas exports and imports by destination: S&P Global base-case outlook to 2050 (Bcm)



Source: S&P Global Commodity Insights.

6.11.2 Kazakhstan's gas imports

Imports remain an important component of the domestic gas balance. In 2022 QazaqGaz reported gas imports of 1.34 Bcm in 2022. S&P Global estimates gas imports (based on physical flows) at 7.4 Bcm in 2022, with 7 Bcm coming from Russia and the remainder from Turkmenistan (see Table 6.4 and Table 6.13). QazaqGaz reported that in 2022 the Orenburg GPZ was not able to provide expected volumes of processed gas back to the domestic market due to technical limitations at the plant.[88] This also fed in to the overall supply crunch in Kazakhstan. For 2023, QazaqGaz sought additional supply guarantees from Russia for other sources of gas should Orenburg GPZ face processing challenges again.

Kazakhstan's imports of Turkmen gas are playing an increasingly important role in ensuring energy security in southern Kazakhstan, especially with the loss of Uzbek imports. In October 2022, Kazakh President Kassym-Jomart Tokayev announced that JSC NC QazaqGaz (QazaqGaz) and Turkmengaz had signed a short-term contract for Turkmen gas imports (0.4 Bcm in 2022) and that Kazakhstan is ready to conclude a long-term agreement for 1.5 Bcm/y. In early 2022, QazaqGaz even announced its ambitions to participate as an upstream partner in upstream development in Turkmenistan, at Galkynysh Phase 3, to increase the company's commercial gas resource base.

In the future, S&P Global expects that Kazakhstan will continue to rely on gas imports, from Russia and Turkmenistan (as opposed to Uzbekistan), to satisfy domestic gas needs. Total Kazakh gas imports are projected to be around 5.6 Bcm in 2030 and increase further to about 11.6 Bcm in 2050 (see Table 6.13). Imports are an effective way to serve border regions in the south and north of the country and provide Kazakhstan greater flexibility in its gas balance. Russian gas is used primarily in Kostanay and Aktobe oblasts, while previously Uzbek and now Turkmen imported gas is used in southern Kazakhstan (Almaty, Taraz, and Shymkent cities and Turkestan oblast).[89] In our base-case outlook, Turkmen gas exports to Kazakhstan will rise, reaching about 2 Bcm/y by 2030 and 6.3 Bcm in 2050. Russian gas imports continue between 4-5 Bcm to 2050. While Kazakhstan is expected to remain a net gas exporter through 2040, thanks in large part to KPO deliveries to the Orenburg GPZ, the country will switch to being a net gas importer by about 2045 (see Figure 6.23).

88 Currently, Orenburg GPZ is facing technical issues related to the acceptance of additional volumes of high-sulfur Karachaganak gas. The situation is exacerbated further due to the Western sanctions on Russia that preclude imports of specialized equipment and parts.

89 The reach of Russian gas imported from the north extends further south, to Mangystau and even Kyzylorda oblasts. The reach of the gas is set to expand further, depending on the gasification decision for northern and eastern Kazakhstan.

6.12 Kazakhstan's Official Gas Balance Outlook to 2030

6.12.1 Official gas production outlook

Kazakhstan's Comprehensive Plan for the Development of the Gas Industry for 2022-2026 (hereafter, the Plan, or Gas Development Plan) provides an official gas balance to 2030. The plan was released in November 2022, so some of the data (2022 estimates) are already dated. The forecast to 2030 envisions gross gas output of 87.089 Bcm, with sales gas output of 42.218 Bcm. In the interim period, the forecast shows an increase in gross gas production in 2024 (by 7.9 Bcm) driven by higher output from the existing fields category and then a significant output increase by 2027 (by 9.7 Bcm), also largely driven by production at the existing fields (see Figure 6.24 Kazakhstan's official raw gas production outlook to 2030). Likely, the 2024 increase corresponds with the expected completion of the Future Growth Project at Tengiz, although that is expected to come towards the end of 2024, and so higher output should only be visible in 2025. The increase in 2027 is likely related to the anticipated start-up of Kashagan phase 2A.

The official gas production outlook also specifies expected gas production volumes from new fields; this volume ramps up to almost 5.5 Bcm by 2030 (see Figure 6.4). About half of production is expected to come from Central Urikhtau (post-2024), West Prorva, Anabay (2023), and Pridorozhnoye (2027). The Plan provides a production forecast for these four fields, with output rising to 2.2 Bcm in 2030. The plan states that additional gas output could come from the Teplovsko-Tokarevskaya group of fields, the Ansagan (Almeks+) and Rozhkovskoye (2023) fields, as well as from Kalamkas-More.[90]

According to the Plan, the share of reinjected gas is set to increase from 32% in 2021 to 50% in 2029.[91] The Plan acknowledges that gas reinjection has been an effective way of maintaining reservoir pressure at the Tengiz and Karachaganak fields, and that lower reinjection will lead to lower liquids output from these projects. Still, the Plan keeps the possibility of utilizing additional gas from these fields open, stating that "at the Tengiz and Karachaganak fields, taking into account the agreed expansion projects, the choice in favor of gas commercialization will be carefully studied and justified with an individual approach in terms of technological and economic parameters and agreed with the authorized state bodies and partners."

Although the potential construction of a 4 Bcm/y gas processing plant at Karachaganak does not seem to be included in the Plan from 2022, a 2023 draft of the Comprehensive Plan for the Development of the Largest Oil and Gas and Petrochemical projects for 2023-2027 includes such a possibility, reportedly without a significant impact on liquids production through 2037 (the end of KPO's Final Production Sharing Agreement). The GPZ could be put into operation by 2030, although under an accelerated schedule the plant could start up by 2028, according to KPO. S&P Global considers this an ambitious timetable and projects the GPZ start-up in 2035.

As for the Kashagan project, where phase 2A and 2B expansion projects are already under active discussion, construction of additional gas processing capacity is seen as a high priority in the Plan. In addition to a new 1 Bcm/y gas processing plant by QazaqGaz using Kashagan gas, negotiations are ongoing for adding even more gas processing capacity.

Indeed, a 2023 draft of the Comprehensive Plan for the Development of the Largest Oil and Gas and Petrochemical Projects for 2023-2027 provides additional details on another Kashagan GPZ. The Ministry of Energy is negotiating with NCOC shareholders on the construction of a gas processing plant with a capacity of 4 Bcm/y as part of the implementation of stage 2A of development. Other investors are also actively being courted as well, with announcements that CNPC and Abu Dhabi investors are evaluating the project.

The main goal of the Gas Development Plan is increasing the production of commercial gas to 42.1 Bcm/y by 2030, to ensure sufficient supply to the domestic market,[92] to maintain the potential for gas exports to China, and to provide feedstock to support petrochemical development. This assumes an average annual sales gas production growth of 4% per year in 2022-30. The balance also assumes that losses and shrinkage decline from about 7.4 Bcm in 2022 to 3.8 Bcm by 2030. Additionally, own use is estimated at 8.7 Bcm in 2030 or 10% of gross output (see Figure 6.25 Gas production outlook according to Kazakhstan's official gas development plan).

6.12.2 Official gas consumption outlook

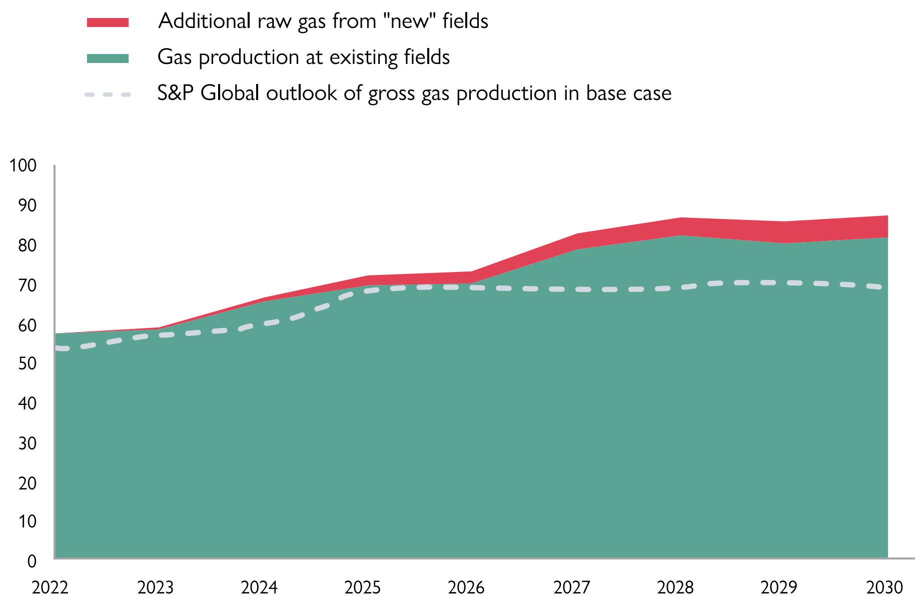
Total domestic gas consumption is expected to grow at an average annual rate of 5.6% between 2022 and 2030, to 32.4 Bcm (see Figure 6.26 Kazakhstan's official gas consumption outlook). Specifically, for existing consumers (comprising the largest share of the total), consumption is expected to grow at an average rate of 2.5% per year, from 18.3 Bcm in 2022 to 22.8 Bcm in 2030. We presume that gasification, even though it is being extended to new households, is still included in this "existing" consumer category. Meanwhile, the new consumer category, which is disaggregated into the power sector, petrochemicals, and gas switching by large industrial producers, grows at an average annual rate of 22.4% during the same time period, albeit from a low base. In absolute terms, the new consumption category grows from 1.5 Bcm in 2022 to 9.6 Bcm in 2030, with the power sector accounting for 72% (6.9 Bcm) of this "new" consumption in 2030. Petrochemicals account for 21% of this category at 2 Bcm, with gas switching by industrial users accounting for the rest (0.7 Bcm). According to the official forecast, this means that Kazakhstan will be short of gas for exports, starting in 2025.

90 The Plan also calls for additional exploration at the Imashevskoye field (172 Bcm), which is a 50-50 shared field between Kazakhstan and Russia.

91 In the Ministry forecast, reinjected gas volumes more than double by 2030 from the current level in absolute terms.

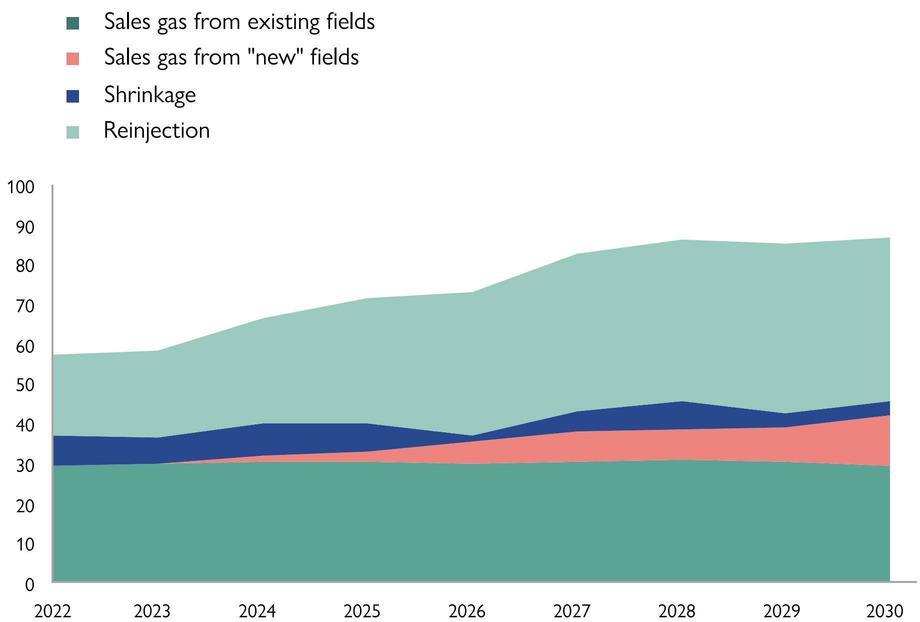
92 Domestic gas supply includes: (1) ensuring stable gas supply to the southern and central regions where gasification is expanding (including to new commercial consumers such as Almaty TETs-2, ERG, and ArcelorMittal JSC); and (2) supporting the planned switching of heat-and-power stations to gas.

Figure 6.24 Kazakhstan's official raw gas production outlook to 2030 (Bcm)



Source: Kazakhstan's Comprehensive Plan for the Development of the Gas Industry for 2022-2026, S&P Global Commodity Insights.

Figure 6.25 Gas production outlook according to Kazakhstan's official gas development plan (Bcm)



Source: Kazakhstan's Comprehensive Plan for the Development of the Gas Industry for 2022-2026, S&P Global Commodity Insights.

Comparing this latest forecast to prior ones issued in 2019 and 2021, the most significant revision was in projected petrochemical demand, which was revised down from ~5 Bcm in the 2019 forecast to 2.5 Bcm in the 2021 forecast, before settling at 2 Bcm in the 2022 forecast. This significant change from just a few years ago is likely explained by a recognition that available feedstock (methane) is lacking in the medium term.

The demand by "new" power sector generation was also revised, but upwards from 5.7 Bcm by 2030 in the 2021 forecast to 6.9 Bcm by 2030 in the 2022 forecast. This forecast seems overly ambitious. The list of the planned additions in the power sector is broadly known, and S&P Global expects that many of these additions that will occur after 2030. There are three projects, however, clearly given a priority (included in Decree 730 on "Sustainable Economic Growth Aimed at Improving the Well-being of Kazakhstan's Nationals," from 12 October, 2021).[93] Those are the 1 GW combined-cycle gas turbine (CCGT) project in Turkestan, 450 MW TETs-2 in Almaty, and 250 MW CCGT in Kyzylorda. The current list of additional gas-fired capacity (including the aforementioned three) is as follows:

- ***Turkestan Oblast CCGT (up to 1 GW).*** In July 2022, Turkestan CCGT LLP (50% owned by NWF Samruk-Kazyna) won a tender for the construction of a gas-fired power plant to increase flexible capacity in the national power grid.[94] With a capacity of up to 1000 MW and a tariff of 16,275,800 tenge/MW/month (ex-VAT), the plant's commissioning date was supposed to be in 2026, but the schedule has already slipped to 2027. In March 2023, a consortium of Korean Doosan Enerbility and Kazakh Bazis Construction won a tender for turnkey construction of the plant at an estimated cost of 700 billion tenge ($1.5 billion). Investors are expected to recoup their investments in 15 years. In June 2023, mobilization of the construction equipment reportedly began, with actual construction beginning in July 2023. The plant is expected to consume about 1.15 Bcm/y, supplied via the BBS or BGR-TBA pipelines.
- ***Almaty TETs-2 conversion to gas (510 MW).*** In May 2023, a consortium from China won the tender to convert the heat-and-power plant to gas, in order to reduce air pollution level in Almaty city.[95] The consortium includes Dongfang Electric International Corporation, Powerchina Sepco 1 Electric Power Construction Co. Ltd, and Powerchina Hebei Electric Power Engineering Co. Ltd. The total cost of the project is estimated at 435.8 billion tenge ($968 billion), financed with a 117 billion tenge ($260 million) loan from the Development Bank of Kazakhstan (DBK), 87.16 billion tenge coming from the plant's owner Almaty Electric Stations (AIES), and the rest provided by loans from the European Bank for Reconstruction and Development, the Asian Development Bank, and the Development Bank of Kazakhstan. Following modernization and conversion to gas, the plant's capacity will increase from 510 MW to 600 MW; the plant will also produce heat (957 Gcal/h capacity). The expected commissioning date is set for December 2026. Construction was supposed to start during the summer of 2023. Gas consumption is projected at 0.8 Bcm/y.
- ***CCGT in Kyzylorda city (250 MW)***. In July 2022, Turkey's Aksa Enerji Üretim A.Ş. won an auction for the construction of a CCGT (with at least 240 MW capacity) with flexible generation capacity in Kyzylorda Oblast.[96] The plant's estimated cost is 215 billion tenge ($477 million) with 2025 as the initial start-up date, although this also appears to have slipped to at least 2026. In accordance with a long-term (15 years) agreement with the Settlement and Financial Center for the Support of Renewable Energy Sources LLP, Aksa Enerji Üretim will receive a guaranteed return on investment through its tariff scheme. Construction reportedly started in 2022 with Aksa Enerji reporting in February 2023 of a contract with GE for delivery of two GE 6F.03 gas turbines for the new plant. The plant is expected to consume about 0.3 Bcm/y.

Other projects planned include

- ***CCGT in Zhezkazgan city.*** With a capacity of 100 MW, this project planned to launch in 2026. In August 2023, contracts for the CCGT's construction and for preparation of design documentation were signed with China's Sinohydro Co. Ltd. and Sepco Electric Power Construction Co. The estimated cost of the project is 80 billion tenge ($178 million).
- ***Power plant JSC "TNK Kazchrome."*** This plant, of up to 100 MW (ERG) in Aktobe Oblast, is planned to launch in 2026.
- ***CCGT Shymkent.*** This plant, with a capacity of 450 MW, is being developed by ERG. It is currently planned for launch 2027. The project is under environmental review.
- ***Almaty TETs-3 conversion to gas (450 MW).*** This project is currently planned for completion in 2026. The timeline seems somewhat ambitions, given that the project is currently only in the planning stages. The estimated cost of the project is 324 billion tenge ($720 million).
- ***Almaty TETs-1 conversion to gas (250 MW).*** This project also is currently planned for completion in 2026, but is more likely to materialize post-2030. The estimated cost of the project is 107 billion tenge ($238 million).
- ***TETs-5 conversion to gas.*** This project, located in Kentay city, Turkestan Oblast has a capacity of 36 MW.
- ***TETs-3 in Semey city.*** This plant, with a capacity of 360 MW, is planned to have the capability to run on both coal and natural gas. Currently a feasibility study is being developed. It is planned to be commissioned in 2026, running initially entirely on coal.

Overall, the current outlook clearly envisions greatly increased gas use in the power sector. The question is more about the timing of construction of the new power plants. In S&P Global's view, the three power plants that are in more advanced stages of construction will come online before 2030, while construction of some of the other gas power plants is likely to be more protracted, not only because of the difficulties involving in executing the actual construction, but also due to delays in the availability of gas supply for the plants.

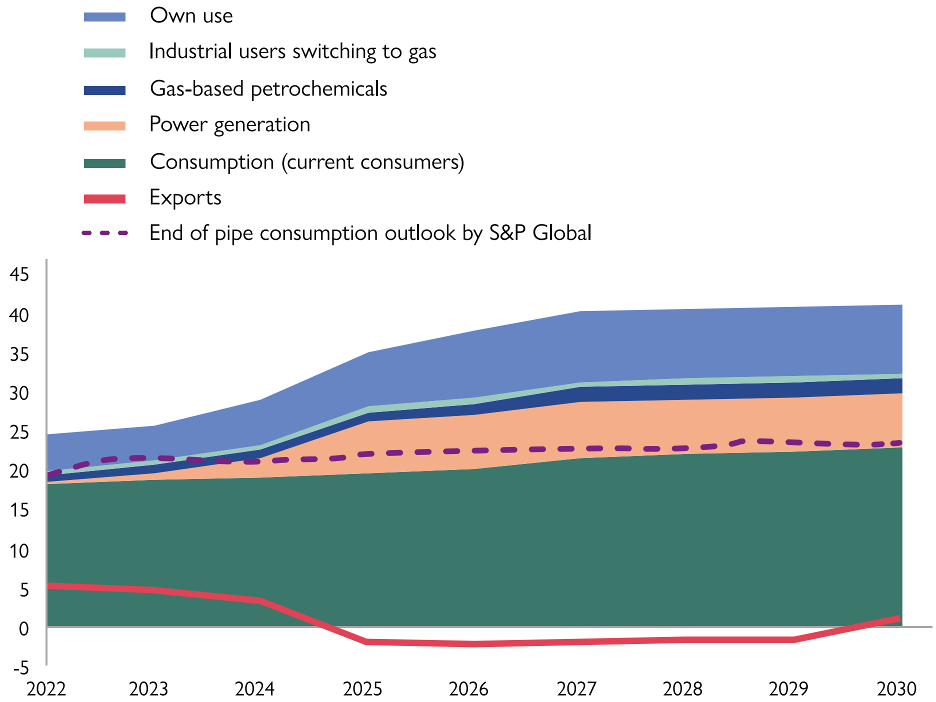
93 https://adilet.zan.kz/rus/docs/P2100000730.

94 On 22 September 2022, Samruk-Kazyna transferred the Turkestan CCGT project to its subsidiary Samruk-Kazyna Construction JSC in 100% trust management.

95 Almaty TETs-2 is an important heat and power plant in the region, providing about 70% of heat in the Almaty district heating zone and 50% of Almaty's electricity.

96 During the auction the price range from the bidders was reported from 11,612,100 to 11,591,000 tenge per MW per month without VAT.

Figure 6.26 Kazakhstan's official gas consumption outlook (Bcm)



Source: Kazakhstan's Comprehensive Plan for the Development of the Gas Industry for 2022-2026, S&P Global Commodity Insights.

6.13 Gas Pricing in Kazakhstan

State regulation of the wholesale price of commercial gas is carried out by the Ministry of Energy and the retail price by the Ministry of National Economy (via KREM, its monopoly regulation agency). The regulation of retail prices affects the entire value chain in the industry. In additional to the changes in producer prices implemented for "new" gas described above, there were several important changes in the wholesale and end-user prices in 2022, including the introduction of new end-consumer categories.

6.13.1 Retail prices

Kazakhstan's State Committee for Regulating Natural Monopolies (KREM) regulates end-user gas prices by region and customer type (residential versus industrial). Its approach is guided not strictly by energy policy per se, but broader macroeconomic considerations, with government inflation targets being perhaps one of the major factors guiding KREM's gas pricing approach. At its core, KREM's pricing mechanism is essentially "cost-plus," with end-user prices reflecting wide differences in gas delivery costs in different parts of Kazakhstan.[97]

On 31 August 2023, KREM's Head of the Department for Regulation of Oil and Gas Transportation, Ruslan Gasanov, in an interview essentially confirmed that the retail price is composed of three components: a wholesale price, a ceiling tariff for gas transportation through distribution networks, and the costs associated with the sale of commercial gas.[98]

In 2022 a change took place in Kazakhstan's end-user pricing policy, with the introduction of four new consumer categories – large commercial consumers,[99] crypto miners, entities purchasing natural gas for the production of LNG or CNG, and socially vulnerable groups (receiving support from the government) (see Table 6.14 Current categories of retail level gas consumers for KTG Aimak).[100] The first two consumer groups (large commercial consumers, crypto miners) are expected to pay higher prices to fully cover higher costs of production and imports of "new" gas. Gas for LNG and CNG is also priced relatively higher. The socially protected segment receives a significantly lower price. Until 2022, there were only six categories of end-users.

According to retail gas prices published by KTG-Aimak, beginning from 1 August 2023 the average price for residential consumers is 17,422 tenge/Mcm; this is 8% higher compared to residential prices introduced on 1 January 2023. For large commercial

97 Kazakhstan's Law on Natural Monopolies and supporting rules issued by KREM establish a methodology to calculate an acceptable profit rate for gas transportation companies (QazaqGaz and subsidiaries) based on their regulated asset base, which reflects their expenditures and investment programs. In practice, determination of end-user prices still follows a "cost-plus" approach where an acceptable profit rate is believed to be no more than 10%.

98 https://forbes.kz/news/2023/08/31/newsid_308124?ysclid=llzdibpn2p222455809; Gasanov did not mention an investment component within the price formula. According to him, at present, the average retail gas price in Kazakhstan is 24.2 tenge per cubic meter and is composed of a wholesale price (18.9 tenge per m^3), plus transportation component (4.3 tenge per m^3), plus costs of sale (0.9 tenge per m^3). These prices exclude VAT.

99 Large commercial consumers are legal entities that consume 10 MMcm/y or more.

100 The Group VII consumer category does not appear in the official price tables.

Table 6.14 Current categories of retail level gas consumers for KTG Aimak

1	Group I	Household consumers (population) receiving services for the retail sale of commercial gas from the gas distribution system
2	Group II	Heat and power companies that purchase commercial gas in order to generate heat for the population
3	Group III	Thermal power companies purchasing commercial gas in order to generate thermal energy for legal entities
4	Group IV	Heat and power companies that purchase commercial gas for the production of electricity
5	Group V	Other consumers not included in I, II, III, IV, VI, VII, VIII and IX consumer groups
6	Group VI	Budgetary organizations maintained at the expense of budgetary funds
7	Group VIII	Legal entities purchasing commercial gas for the production of compressed and (or) liquefied natural gas for the purpose of further sale to consumers
8	Group IX	Household consumers (population) receiving state targeted social assistance and (or) housing assistance
9	Group X	Large commercial customers
10	Group XI	Persons carrying out digital mining or persons producing electrical energy for digital mining

Source: KTG Aimak, S&P Global.

customers and digital miners (new consumer categories) the average price is set at 35,540 tenge/Mcm, more than double the residential rate. For households receiving state support, the price is set at 13,593 tenge/Mcm, about 22% lower than the regular residential price.[101] Retail prices vary widely by region—for example, a crypto miner in Almaty would pay 54,328 tenge/Mcm, while in Astana it would pay 44,552 tenge/Mcm and in West Kazakhstan about 18,766 tenge/Mcm. Prices vary because of the source of gas (domestic versus imports) and the amount of domestic transportation involved.

To curb excessive gas consumption in periods of high gas demand, due, for example, to severe weather, the government of Kazakhstan passed in April 2023 new amendments to the Rules for the retail sale and use of commercial and liquefied petroleum gas, where consumers, including large commercial consumers and crypto miners, that have back-up fuel capabilities can have gas deliveries (consumption) curtailed, especially during the fall-winter heating season. If they withdraw over 5% more gas than allowed in their contracts, gas supply to these consumers can be restricted back to the average daily norm three hours after the consumer is notified about it. Also, if excessive consumption occurs without prior coordination with the gas supplier, these consumers will face payment penalties ranging from 20 to 50% of the price of the gas delivered in excess of the volumes established in the contract, depending on the time of year.[102] The legislation also requires that separate records are kept for the use of commercial gas and electricity for digital mining activities.

Currently, the government is looking into a possibility of introducing differentiated end user gas tariffs to encourage more careful use of natural gas. In March 2023, President Tokayev encouraged the government to consider differentiated tariff approach that is widely used in practice abroad.

6.13.2 Wholesale prices

The Ministry of Energy in coordination with the Ministry of National Economy sets ceiling wholesale prices. At the end of 2022, the government approved amendments to the Law on Gas and Gas Supply, whereby wholesale ceiling prices for natural gas are now set for a five-year period to provide longer-term views for gas market players (previously ceiling prices were set annually). Annual price corrections are allowed, however, with price adjustments taking place on 1 July.[103] Wholesale ceiling prices are set by oblast, and separately for the cities of republican significance, and the capital, as well as for entities who use natural gas to produce CNG or LNG for further sale to end-consumers. Wholesale price ceilings are calculated as weighted average purchase prices in that region, including transportation, but are also supposed to reflect economic and social conditions of regional gas supply. Although there were active discussions over the past few years on lifting the 15% per year limit on changes in ceiling wholesale price, this official rule still stands in 2023.[104]

101 These prices do not include the transportation tariff through the gas distribution system. If the latter is included, then the average residential price is set at 22,234 tenge/Mcm, the price for large commercial consumers and crypto miners is set at 39,811 tenge/Mcm, and the protected group's price is set at 17,379 tenge/Mcm.

102 https://adilet.zan.kz/rus/docs/V1400009936.

103 Adjustments are made no more than once a year on the basis of the national operator's application to the authorized body in connection with a change in the purchase prices of commercial gas, the structure and (or) sources of commercial gas, and (or) tariffs subject to state regulation for the transportation of commercial gas through main gas pipelines and storage of commercial gas in underground gas facilities.

104 See Order of the Minister of Energy of the Republic of Kazakhstan No. 209 of 15 December 2014 "On Approval of the Rules for Determining the Ceiling Prices for the Wholesale Commercial Gas Sales in the Domestic Market of the Republic of Kazakhstan and the Ceiling Prices for the Liquefied Petroleum Gas Sold within the Framework of the Plan for Liquefied Petroleum Gas Supply to the Domestic Market of the Republic of Kazakhstan outside Electronic Sales Platforms," as amended on 30 March 2020. https://adilet.zan.kz/rus/docs/V1400010120.

Another change adopted in December 2022 concerned consumers that are considered "new" gas-fired power projects, where the length of time for which ceiling wholesale prices are set was reduced from ten to five years. These prices are set separately for each consumer and for new power plants included in the strategic list of power plants prices are now based on the weighted cost of gas +7% and, if necessary, can be adjusted annually on 1 July.[105]

The Order of the Minister of Energy of the Republic of Kazakhstan No. 246 dated 30 June 2023 approved ceiling wholesale prices in Kazakhstan's domestic market for the commercial gas intended for subsequent sale to large commercial consumers, digital miners, or producers of electricity for digital mining activities for the period of 1 July 2023 to 30 June 2024. Provisions are made for the possibility of an annual increase in the range of 20-75% in the following years in order to move gas prices to economic levels.

The new ceiling wholesale gas prices (effective 1 July 2023) increased on average by 10% across all oblasts and cities (see Table 6.15 Kazakhstan's wholesale ceiling gas prices to 2028). Ceiling wholesale prices increased the most (by 15% year on year) in West Kazakhstan, Atyrau, and Aktobe oblasts. All regions served by the Saryarka pipeline (Astana city and Akmola, Karaganda, and Ulytau oblasts) had a 5% price increase, while prices in East Kazakhstan Oblast remained unchanged. Increases in the rest of the regions ranged between 10% and 13%. Ceiling wholesale prices are expected to increase on average at almost 9% per year between 2022 and 2028, with West Kazakhstan, Atyrau, and Mangystau oblasts showing the slowest growth rate and the regions in southern Kazakhstan (Almaty, Zhambyl, and Kyzylorda oblasts) and Aktobe and Kostanay set to see double-digit price hikes.

Table 6.15 Kazakhstan's wholesale ceiling gas prices to 2028 (tenge per Mcm, excluding VAT)

		1 July 2018 - 30 June 2019	1 July 2019 - 30 June 2020	1 July 2020 - 30 June 2021	1 July 2021 - 30 June 2022	1 July 2022- 30 June 2023	1 July 2023 - 30 June 2024	*1 July 2024 - 30 June 2025*	*1 July 2025 - 30 June 2026*	*1 July 2026 - 30 June 2027*	*1 July 2027 - 30 June 2028*
1	Astana city			24,537	25,764	25,764	27,052	*28,405*	*31,245*	*34,370*	*36,135*
2	Almaty city	25,073	19,405	19,405	21,346	22,413	25,103	*28,115*	*32,322*	*37,182*	*42,759*
3	Shymkent city		20,819	20,819	22,276	23,390	26,197	*29,340*	*33,741*	*38,803*	*41,158*
4	Akmola Oblast			24,537	25,764	25,764	27,052	*28,405*	*31,245*	*34,370*	*36,135*
5	Aktobe Oblast	6,081	5,574	5,574	6,410	7,372	8,478	*9,749*	*11,212*	*12,894*	*14,828*
6	Almaty Oblast	25,073	19,405	19,405	21,346	22,413	25,103	*28,115*	*32,322*	*37,182*	*42,759*
7	Atyrau Oblast	6,340	6,340	6,340	7,291	8,385	9,643	*11,089*	*11,427*	*11,427*	*11,427*
8	West Kazakhstan Oblast	12,061	10,541	10,541	12,122	12,728	14,637	*15,065*	*15,065*	*15,065*	*15,065*
9	Zhambyl Oblast	23,317	18,775	18,775	20,653	21,686	23,855	*26,240*	*30,176*	*34,702*	*39,908*
10	Karaganda Oblast			24,537	24,764	25,764	27,052	*28,405*	*31,245*	*34,370*	*36,135*
11	Kyzylorda Oblast	8,677	7,268	7,268	8,358	9,194	10,113	*11,125*	*12,793*	*14,712*	*16,919*
12	Kostanay Oblast	19,732	17,305	17,305	19,036	19,988	22,387	*25,073*	*28,834*	*33,159*	*33,627*
13	Mangystau Oblast	13,957	12,552	12,552	14,435	16,167	18,300	*18,300*	*18,300*	*18,300*	*18,300*
14	Turkestan Oblast		20,819	20,819	22,276	23,390	26,197	*29,340*	*33,741*	*38,803*	*41,158*
15	East Kazakhstan Oblast	7,563	7,563	7,563	7,563	7,563	7,563	*7,563*	*7,563*	*7,563*	*7,563*
16	Zhetysu Oblast					22,413	25,103	*28,115*	*32,322*	*37,182*	*42,759*
17	Ulytau Oblast					25,764	27,052	*28,405*	*31,245*	*34,370*	*36,135*
	Simple average	14,787	13,864	15,998	17,294	18,833	20,640	*22,403*	*24,988*	*27,909*	*30,163*

Source: Kazakhstan's Ministry of Energy, S&P Global.

105 In the past, gas prices for the new power plants were set for ten years at $60/Mcm. https://adilet.zan.kz/rus/docs/V2300032937.

In December 2022, an amendment to the Law "On Natural Monopolies" allowed a national operator, including QazaqGaz, to amend approved tariff estimates in case of receipt on its balance sheet and (or) in trust management of property (used in the technological cycle in the provision of regulated services by subjects of natural monopolies) from local authorities.

6.13.3 Pipeline tariffs

Gas pipeline transportation tariffs for domestic deliveries are regulated by KREM and are often guided by social and inflation concerns. Historically these tariffs tended to rise only slowly and sometimes were revised downward. With the construction of the Saryarka pipeline and the need to pay for its loans, however, the domestic tariff increased substantially, from 2,333.3 tenge/Mcm ($5.7/Mcm) in 2020 to 4,551 tenge/Mcm ($10.65/Mcm) in 2021. For the period 2022-26, the tariff for domestic gas deliveries via the ICA system is set at 5,286 tenge/Mcm ($11.75/Mcm) (see Table 6.16 S&P Global's outlook for trunk and distribution gas pipeline transportation tariffs in Kazakhstan, 2018-26).[106]

In August 2023, ICA already requested a 2.6% tariff increase to 5,426 tenge/Mcm to reflect rising wages at the company.[107] Besides operational costs, QazaqGaz contends that the current ICA tariff does not stimulate investment in the gas transportation system. A similar contention applies to distribution tariffs. In 2022, for example, the simple unweighted average KTG-Aimak distribution tariff *decreased* by 12% year on year to 4,490 tenge/Mcm ($9.98/Mcm) despite all of the expenditure and effort going into expanding the distribution system to support gasification.

Tariffs for domestic shipments on most trunk pipelines are set by the regulator as postage stamp–type tariffs (tenge/Mcm) that do not reflect distance. However, this probably will change in the future, as the gas sector moves toward a market-based (or at least cost-reflective) future, where tariffs reflect the distance gas travels. Such an approach already has been applied to the BBS pipeline tariff, where from 1 January 2021 the tariff was set in tenge per Mcm per 100 km. For 2022 the BBS tariff was set at 1,158.41 tenge/Mcm/100 km ($2.51/Mcm/100 km, without VAT) or 15,557 tenge/Mcm ($34.57/Mcm, without VAT), applicable to both exports and domestic deliveries.[108] The distance-based BBS tariff lowers the cost of gas delivered to Astana via the Saryarka pipeline, because the gas travels only 944 km on the BBS (64% of the distance) to the Karaozek compressor station, rather than the pipeline's entire 1,477 km length to Shymkent.

KREM, through its regional offices, sets distribution tariffs for a five-year period, but tariffs are often adjusted more frequently, sometimes biannually, to reflect ongoing investments in expanding local distribution infrastructure.[109]

Unlike tariffs for domestic deliveries, gas transportation tariffs for international transit via ICA and other QazaqGaz-operated pipelines are established through bilateral negotiations and are not subject to regulation by KREM. ICA and Gazprom negotiate the tariff for the transit of Uzbek and Turkmen gas to Russia, which is currently set at $2.42/Mcm/100 km. The tariff for shipments to China via CAGP (or Asia Gas Pipeline [AGP] on Kazakh territory) is $3.58/Mcm/100 km. The CAGP tariff has not been altered in recent years and will likely remain relatively stable over the near term. The transit fee for exporting gas by TCO (or the few other Kazakh producers with the right to export) also are negotiated with ICA. For TCO, it is $5/Mcm/100 km, while KRG's transit tariff is $2.42/Mcm/100 km.

In the medium term to 2026, transportation tariffs are largely set and we do not expect dramatic changes in most domestic gas transportation tariffs through the mid-2020s; they will likely move in tandem with inflation and reflect mainly maintenance expenditures over the near term. However, construction of the second string of the BBS pipeline, and later on the gasification network in the north of the country, will necessitate a substantial increase in tariffs. Additionally, QazaqGaz is focused on substantial upgrades of its dilapidated pipeline infrastructure, even though the company argues that the current approach to transportation tariffs fails to stimulate investment in the gas transportation system.

106 The 2022-26 ICA tariff was converted to dollars using an exchange rate of 450 tenge per dollar.

107 Recent amendments to the legislation regulating natural monopolies includes a provision where an increase in monthly regional wages, calculated by official statistics, may serve as grounds for tariff revisions before the established deadlines.

108 The rate of 15,557 tenge/Mcm is apparently calculated based on the distance along the Bozoy-Shymkent segment only, and does not include the Beyneu-Bozoy segment. For details on the BBS gas transportation rate, see the BBS report entitled *Otchet o deyatel'nosti SEM po predostavleniyu reguliruemykh uslug pered potrebitelyami za 2020 god* accessed 19 June 2021, at https://bsgp.kz/ru_RU/%d0%b4%d0%be%d0%ba%d1%83%d0%bc%d0%b5%d0%bd%d1%82%d0%b0%d1%86%d0%b8%d1%8f/%d0%b4%d0%be%d0%ba%d1%83%d0%bc%d0%b5%d0%bd%d1%82%d1%8b/.

109 According to the Law on Natural Monopolies (Article 22 subparagraph 3), KREM has the right to initiate a review of transportation tariffs no more than twice a year, and at the initiative of the subject of natural monopoly - no more than once a year.

Table 6.16 S&P Global's outlook for trunk and distribution gas pipeline transportation tariffs in Kazakhstan, 2018-26

								Forecast		
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	***2024***	***2025***	***2026***
Intergas Central Asia (ICA)										
Trunk pipeline (domestic deliveries)	KZT/Mcm*	**2,212.7**	**2,212.7**	**2,212.7**	**2,212.7**	**5,285.7**	**5,286**	**5,286**	**5,286**	**5,286**
Undeground storage fee	KZT/Mcm*/ month	280.92	280.92	280.92	280.92	478.35	478.35	478.35	478.35	478.35
For export for PJSC Gazprom & subsidiaries	US$/ Mcm/100km	2.00	2.00	2.00	2.00	2.42	2.42	2.42	2.42	2.42
For export for JSC UztransGaz (i.e. transit of Uzbek gas to Russia)**	US$/ Mcm/100km	1.70	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90
For export by Kazakh producers***	US$/ Mcm/100km	3.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
For export by KazRosGaz, CNPC-AMGZ	US$/ Mcm/100km		2.00	2.00	2.00	2.41	2.41	2.41	2.41	2.41
KTG Aimak										
Trunk pipeline (domestic deliveries)	KZT/Mcm*	**591.80**	**591.80**	**591.80**	**591.80**	**605.71**				
Distribution pipeline (domestic deliveries)										
Aktobe	KZT/Mcm*	5,600	4,891	4,891	5,107	5,225	5,524	5,690	5,861	5,861
Zhambyl	KZT/Mcm*	7,103	6,443	6,443	8,665	8,408	8,695	8,695	8,695	8,695
West Kazakhstan	KZT/Mcm*	2,914	2,615	2,615	2,723	2,720	2,590	2,687	2,768	2,832
Kyzylorda	KZT/Mcm*	9,084	9,084	9,804	9,458	5,941	3,320	5,941	6,111	6,254
Turkestan Oblast (including Shymkent city)****	KZT/Mcm*	8,061	7,037	6,637	6,911	4,579	4,620	4,620	4,620	4,620
Mangystau	KZT/Mcm*	2,455	2,393	2,393	2,491	2,393	2,393	2,393	2,393	2,393
Karaganda	KZT/Mcm*				6,552	6,552	4,987	5,182	5,330	5,455
Kostanay	KZT/Mcm*	4,923	4,923	4,923	5,126	4,669	4,669	4,669	4,669	4,669
East Kazakhstan	KZT/Mcm*	1,550	1,550	1,550	1,550	1,388	1,821	1,821	1,821	1,821
Atyrau	KZT/Mcm*	1,769	1,769	1,769	1,842	1,095	1,229	1,229	1,229	1,229
Almaty	KZT/Mcm*	6,009	4,493	4,310	4,488	4,659	4,745	4,074	4,059	3,997
Almaty city	KZT/Mcm*					4,659	4,745	4,074	4,059	3,997
Astana city	KZT/Mcm*			4,108	6,159	6,084	6,084	6,322	6,503	6,655
Beyneu-Bozoi-Shymkent (BBS)					5,089	4,490	4,263	4,415	4,470	4,498
For domestic deliveries, transit, and exports*****	KZT/Mcm*	18,071	16,574							
For domestic deliveries, transit, and exports	KZT/Mcm/100 km			1,200	1,158	1,158	1,332	1,424	1,507	1,588
For the entire pipeline length	KZT/Mcm*			17,724	15,557	15,557	17,316	18,514	19,597	20,644
Central Asia-China Gas Pipeline (CAGP)										
Lines ABC - export										
Transportation of natural gas from BBS to China	US$/ Mcm/100km	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58
Line AB - gas transit										
AGP	US$/ Mcm/100km	3.58	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57
AGP-Khorgos (Kazakhstan-China border)	US$/ Mcm/100km		7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45

Continuation

Table 6.16 S&P Global's outlook for trunk and distribution gas pipeline transportation tariffs in Kazakhstan, 2018–26

								Forecast		
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	***2024***	***2025***	***2026***
Line C - gas transit										
AGP	US$/ Mcm/100km		3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57
AGP-Khorgos (Kazakhstan-China border)	US$/ Mcm/100km		7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45
Line C										
Deliveries to domestic market	KZT/Mcm*	3,494.4	3,494.4							
Deliveries to domestic market	KZT/Mcm/100 km			555.5	555.5	555.5	555.5	555.5	555.5	555.5
Inflation, CPI	% change year-on-year	6.03	5.24	6.75	8.37	14.90	10.24	6.92	5.85	5.34

Notes: *Excludes VAT.
**Relevant entities include TCO and QazaqGaz(KTG).
***Similar tariff would apply to Turkmen volumes bought by Gazprom as the point of sale/title transfer occurs at the respective national border. Gazprom is therefore responsible for paying for transportation across Kazakhstan. Gazprom and ICA eliminated ship or pay terms in 2017. Contracts between ICA and Gazprom are determined annually, and payment is based on volumes shipped.
****In 2020, KTGA tariff was 6,248.66 for population in Turkestan oblast and Shymkent.
*****Officially, as per KREM, the tariff was set at 16,574 KZT/Mcm starting from May 2019. KMG also reported 17,073 KZT/Mcm for 12M 2019, although in one of the AP slides shared called "Evolution of transportation tariffs," the BBS tariff for 2019 was 17,140 KZT/Mcm.
Source: KREM, KTG Aimak, BBS, AGP, S&P Global.

6.13.4 EAEU Single Gas Market and gas price harmonization

The five member-states of the Eurasian Economic Union (EAEU)—Armenia, Belarus, Kazakhstan, Kyrgyzstan, and Russia—plan to create common oil and gas markets by 2025 (see Chapter 3). As Kazakhstan accedes to rules of EAEU common gas market, end-user gas prices between Kazakhstan and the Russian Federation need to be harmonized, as part of a general movement toward integrated open markets. S&P Global expects domestic prices in Kazakhstan to converge with domestic prices in Russia, given that gas production, trade, and the size of domestic market in Russia all are much larger than in any other EAEU members.

S&P Global expects that price harmonization will likely materialize during 2025-30 or possibly slightly later once various details of the common market framework are finalized. During this process, end-user gas prices in Kazakhstan would need to rise substantially, as Russian prices are much higher than those in Kazakhstan.

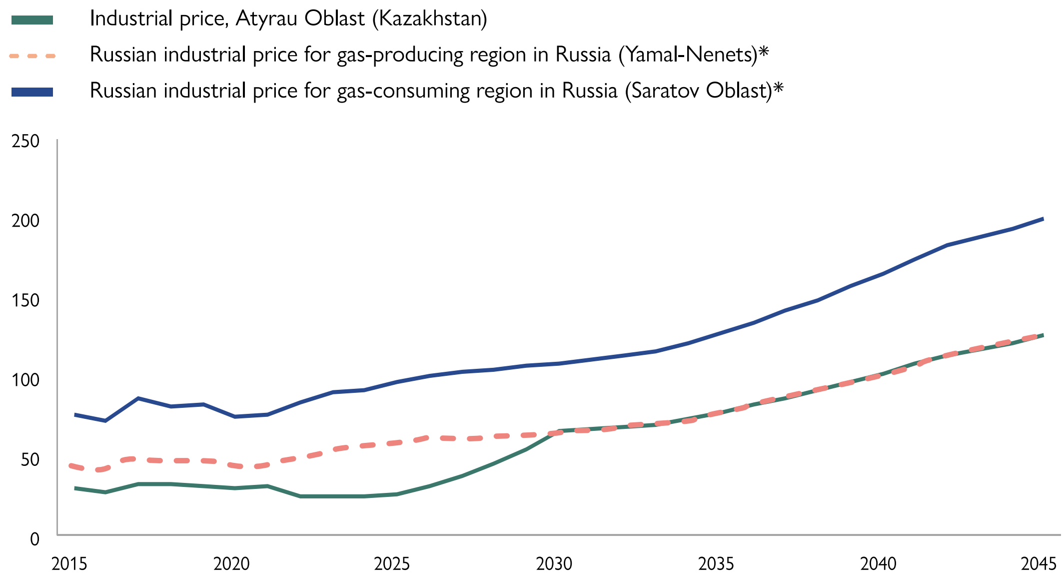
Russian domestic gas prices are differentiated by consumer group and price zones, depending on transportation distances from the main producing region in West Siberia to consumers. Kazakhstan's policymakers would need to decide with which Russian pricing zone(s) to harmonize, especially in its main production centers in western Kazakhstan.[110] In S&P Global's assessment, Kazakhstan should harmonize its natural gas prices with those in Russia's gas-producing regions (e.g., Yamal-Nenets Okrug) and not with the higher prices in European Russia's consuming regions, such as neighboring Saratov Oblast (see Figure 6.27 Price outlook for natural gas consumed in industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug). Such an approach would:

- allow Kazakhstan's manufacturing industry to remain competitive within the broader EAEU economic space
- enable the government to raise consumer prices more gradually (although still significantly)
- help QazaqGaz achieve cost-recovery in the domestic segment of its operations
- potentially incentivize new commercial gas production.

Under an EAEU integration scenario, industrial gas prices in Kazakhstan would need to appreciate by about 19.9% annually during 2025–30 to reach parity with those in Russia's gas-producing regions. Of course, one of the key unknowns in this forecast is the ruble exchange rate and its relation with the tenge. The tenge historically has been affected by ruble moves, and this dynamic is expected to continue into the future. If the ruble depreciates even more significantly than in the recent past, the gap Kazakh domestic gas prices would need to close could become smaller. An additional emerging challenge is that domestic prices within Russia are now expected to increase more substantially than prior to the Ukraine conflict because of the need to generate more state budget revenue given reduced export volumes.

110 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 6.27 Price outlook for natural gas consumed in industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug ($/Mcm)



Notes: *Prices include VAT. Assumes Atyrau prices close price gap with Yamal-Nenets in 2025-30.
Source: S&P Global Commodity Insights.

6.14 Kazakhstan's LPGs Sector

6.14.1 Production

The potential for the prolific expansion of gas-based (methane) petrochemical development in Kazakhstan appears somewhat limited by the tight domestic supply of commercial gas. However, in contrast to methane supplies, liquefied petroleum gas (LPG) (and ethane) feedstocks in the country are relatively abundant.[111] Kazakhstan is a sizable producer and exporter of LPGs, producing around 3.2 MMt annually over the period 2019–21, although output fell by 12.5% to 2.8 MMt in 2022 as a result of lower associated gas output at the "Big 3" projects as well as the generally depressed demand environment in certain export markets (Ukraine) following the outbreak of armed conflict there (see Figure 6.28 LPG production in Kazakhstan by producer).

Most of Kazakhstan's LPG production (73%) comes from processing of associated gas at GPZs, with oil refining contributing the remainder. TCO is the largest individual producer by far, accounting for 43% of total output in 2022 (or 1.2 MMt of the 2.8 MMt total). Other important gas-processing LPG producers include: the Zhanazhol GPZ owned by CNPC-AktobeMunayGaz (511.3 Mt in 2022; 18% of total output) and KazGPZ at KMG's Uzen field (181.6 Mt; 6.4%) (see Figure 6.28). The share of LPGs produced at the country's three main oil refineries—Atyrau, Pavlodar, and Shymkent—increased dramatically following the completion of Kazakhstan's refinery modernization program in 2018 to deepen their refining operations, rising from 14% in 2017 to 27% in 2022.

Despite sizable LPG output and exports in Kazakhstan, news of domestic LPG shortages are widely reported, especially during the past year.[112] The Ministry of Energy sets quotas for LPG supplies from producers to the domestic market at regulated prices. Some LPG producers, such as those operating under Production Sharing Agreements (PSA) or other arrangements, most notably TCO and ZhaikMunay, do not receive domestic delivery quotas, as they have the contractual right to export 100% of their output. Thus, the effective amount of LPGs available for the domestic market, without TCO/ZhaikMunay volumes, is significantly less. In 2022, available volumes were only around 1.6 MMt vs. estimated LPG demand of 1.8 MMt. The Ministry reports that with current LPG production (not subject to PSAs), it can cover only 90% of LPG demand in the country and that the situation gets significantly worse during maintenance periods. In 2023, TCO sold some of its LPG volumes on the domestic market (but at commercial rather than regulated prices) to help cover the deficit.

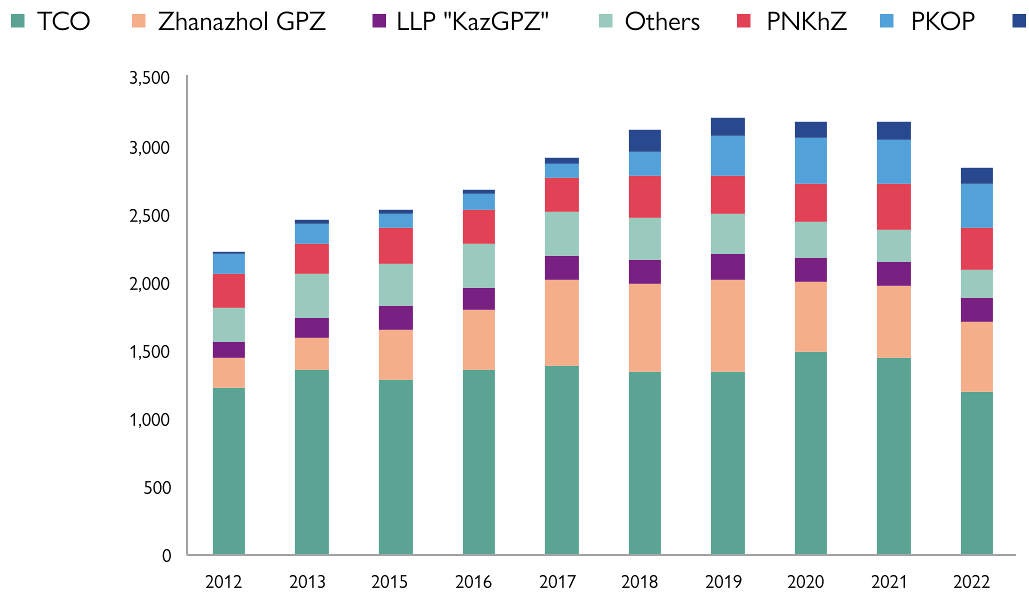
In August 2023, the Ministry proposed a draft order to ban for three years all exports of LPGs by road and for six months exports by rail. This would be a continuation and tightening of the existing LPG export ban that covers only road exports.[113]

111 See *The National Energy Report 2021*, p. 132.

112 Most recently in August 2023, an accident at the Mangystau Nuclear Power Engineering Plant (MAEK) resulted in LPG shortages in Mangystau Oblast because the lack of electricity led to a shutdown at the Atyrau refinery.

113 In 2020, the Minister of Energy issued a 3-year ban on LPG exports by road, according to an Order dated 7 October 2020 No. 347.

Figure 6.28 LPG production in Kazakhstan by producer (thousand tons)



Source: S&P Global Commodity Insights, Ministry of Energy RK.

6.14.2 Demand

In 2022, Kazakhstan consumed only about two-thirds (1.8 MMt) of the LPGs it produced (2.8 MMt), making it a sizable net exporter (see Figure 6.29 Kazakhstan's LPG balance). However, strong growth in domestic demand has occurred in all regions of Kazakhstan since 2015, with LPG consumption increasing on average by 16% annually through 2021. In 2022, aggregate LPG consumption increased even more sharply, by 21%, driven mainly by higher demand in (vehicle) transportation. Kazakhstan's Southern zone, the country's most populous region, was the largest LPG consumer in 2022, accounting for 41% of total consumption, followed by the North-Central region, which is not currently well supplied with pipeline gas (28%), and the Western and Northwestern zones (18% and 11%, respectively) (see Figure 6.30 LPGs consumption by consumption zone in 2022). In 2023, LPG demand continued to increase strongly, with monthly deliveries to the domestic market exceeding historical volumes over past several years in almost every month during January-July 2023. Correspondingly, exports of LPGs (mostly by TCO and Zhaikmunay) have declined so far in 2023 relatively to historical monthly figures.

Sectorally, LPG consumption in automobile transport (i.e., LPG use as motor fuel in private vehicles) appears to be the largest consumption segment, accounting for about 36% of demand in 2022, followed by the residential sector (e.g., home heating and cooking; 21% of demand), the oil and gas sector itself (16%), and industry (10%) (see Figure 6.31 LPG consumption by sector in 2022). LPGs use in petrochemical sector currently remains limited; in 2021, the sector consumed a mere 2,700 tons of LPGs, although up significantly from only 200 tons in 2020.[114] However, petrochemicals are expected to be an area of major demand growth in the future, starting with the launch of the KPI polypropylene plant in 2022 and other new facilities that are under construction, including a large polyethylene plant (also in Atyrau Oblast; see below and Section 6.10.2)

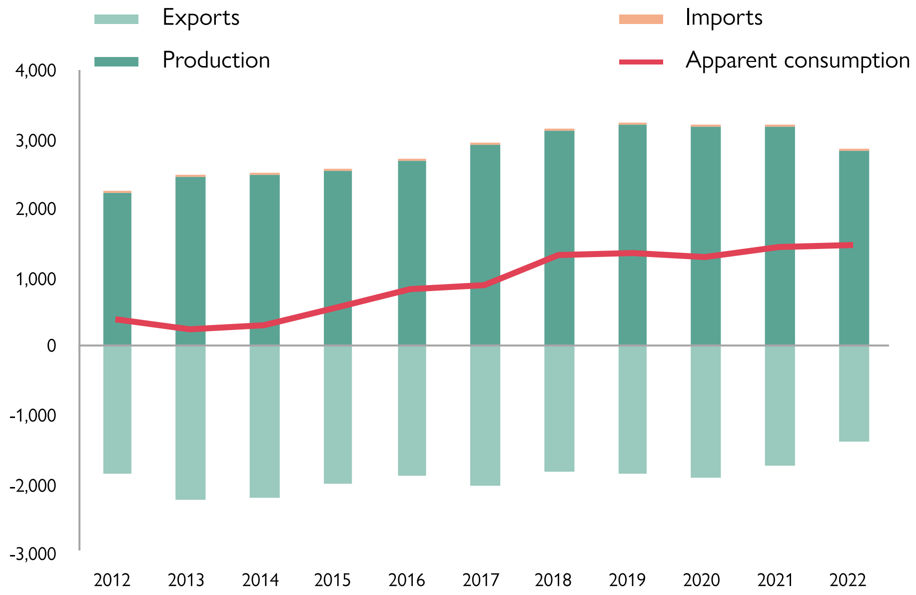
Use of LPG in the transport sector has been expanding rapidly in recent years, reflecting the relatively low retail price for LPGs compared to gasoline (see Figure 6.32 Registered light vehicles in Kazakhstan by type of fuel used). Autogas (retail sales) usage has become quite significant in recent years, reaching over 539,000 tons in 2022 (almost a 10% increase year on year).[115] According to the Ministry of Energy, in 2022 the total number of vehicles running on LPGs increased by almost 57% to 490,000 vehicles (from 313,000 in 2021). Meanwhile, according to Kazakhstan's National Bureau of Statistics, during 2015-22, the number of LPG-fueled passenger cars nationwide increased nearly sevenfold, reaching just under 350,000 vehicles, or 8% of the total car fleet.

In 2022, 2,195 filling stations in Kazakhstan provided LPG fueling services, a nearly threefold increase since 2015 (from 754) (see Figure 6.33 Number of LPGs filling stations by region). It is unclear why the number of stations declined, compared to 2021 (perhaps the definition was changed). According to the latest available data, the value of LPG sales at filling stations was 7.3% of the total value of sold fuels in 2021, compared with only 2.4% in 2015. The share of LPGs sold at filling stations—as opposed to other outlets—reached 63% of total LPG consumption in Kazakhstan in 2021, up from 55% in 2015. These trends likely continued in 2022-23. Southern Kazakhstan had the greatest number of LPG filling stations in 2022 (1,058), while Western Kazakhstan had the most LPG-fueled cars (~133,000).

114 Kazakhstan's National Statistics Bureau reported that no LPGs were used in the petchem sector in 2022.

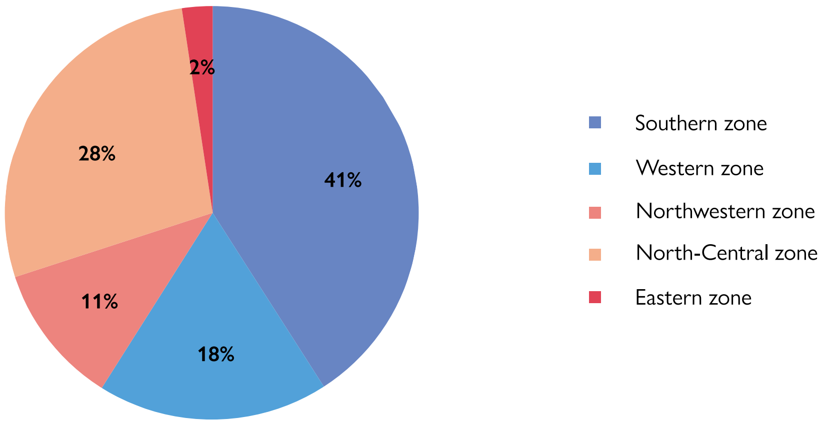
115 The share of LPG in the total volume of motor fuel sales at filling stations in Kazakhstan rose from 5.6% in 2015 to 12.6% in 2021. Comparable data for 2022 are not available from Kazakhstan's National Statistical Agency.

Figure 6.29 Kazakhstan's LPG balance (thousand tons)



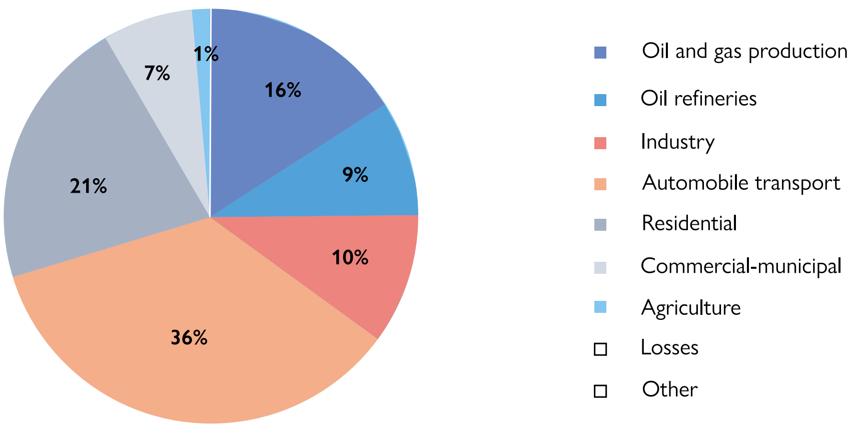
Source: S&P Global Commodity Insights.

Figure 6.30 LPGs consumption by consumption zone in 2022 (% of total)



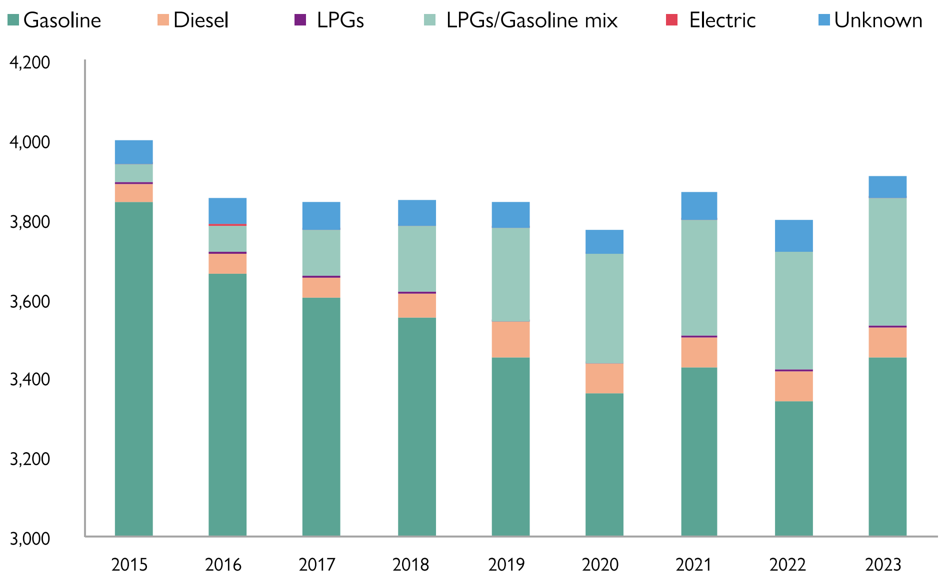
Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

Figure 6.31 LPG consumption by sector in 2022 (% of total)



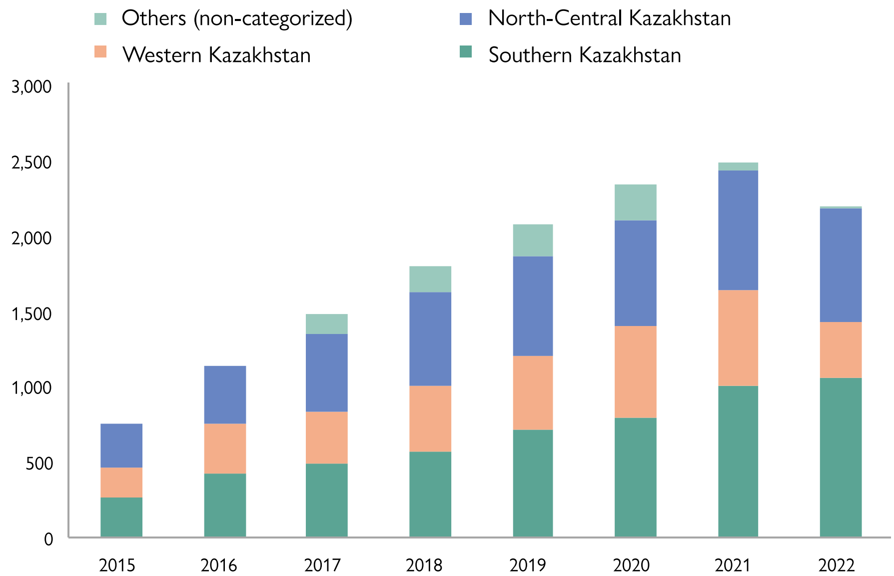
Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

Figure 6.32 Registered light vehicles in Kazakhstan by type of fuel used (thousand units)



Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

Figure 6.33 Number of LPGs filling stations by region



Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

6.14.3 Market structure and pricing dynamics

Since 2019, Kazakhstan's domestic LPG market has been going through a transition from highly regulated to semi-liberalized, but the pace has varied over time. The liberalization drive aims at four key objectives:

- increase wholesale producer prices to incentivize plant modernization and output expansion
- reduce the share of the overall value chain captured by intermediaries (gas distributors)
- strengthen competition
- increase transparency in deliveries to the market.

In 2018, the Law "On Gas and Gas Supply" was amended to introduce LPG trading through electronic trading platforms (ETPs), with LPG exchange trading commencing in February 2019. By the end of 2019, ~15% of LPGs were sold via exchanges; by the end of 2021, that share had increased to ~70%.[116] By early 2022, practically all LPG trade (except for LPG sales to special categories of household consumers and petrochemical enterprises that remained under state regulation) had transitioned to electronic trading.

Nonetheless, LPG pricing has proven to be a sensitive and sometimes contentious issue for Kazakhstan, with rapid price rises in 2021 prompting the outbreak of political unrest in January 2022. During 2021, the average retail price paid by consumers for LPG nearly doubled, rising from 60.1 tenge/liter in December 2020 to 111.8 tenge/liter in December 2021 (see Figure 6.34 LPG prices at gas filling stations by region in 2021 and Figure 6.35 Average LPG retail prices in Kazakhstan by month in 2019-23). Yet despite the increase, Kazakh prices still remained relatively low compared to other countries. In November 2021, the average retail LPG price in Kazakhstan was still only about $0.21 per liter compared with $0.85 per liter in the European Union, and $0.42 per liter in Russia.

After the January 2022 unrest in Kazakhstan, the government stepped back in to directly regulate the domestic LPG market. It instituted a number of measures, including:

- Suspending LPG sales on exchanges.
- Reducing the regulated wholesale price ("regulated LPG ceiling price outside of exchanges") for LPGs from 38,700 to 28,000 tenge/ton ($89.24 to $64.57/ton), but on 1 July 2022 the ceiling was raised to 33,600 tenge/ton ($70.58/ton), and it was further raised to 40,320 tenge/ton ($90.57/ton ex.VAT) in July 2023 (see Figure 6.36 Average monthly LPG prices in Kazakhstan).[117]
- Establishing a price corridor for LPG retail prices in a range of 50-75 tenge/liter (depending upon oblast); in July 2023 the retail price corridor shifted higher to 54-81 tenge/liter (without VAT).[118]
- Suspending trading rules until 1 January 2023 (the rules were canceled altogether in June 2022),[119] with the Ministry of Energy directly regulating LPG trading outside of trading exchanges:[120]
    - The Ministry of Energy determined a plan for LPG deliveries to the domestic market and set wholesale prices jointly with the Ministry of National Economy.[121]
- Amending the Standard Rules for Exchange Trading on 19 July 2022, setting limits on acceptable price movements during trading.[122]
- Initiating an amendment to the LPG supply plan, expanding the list of entities entitled to buy either at wholesale or retail prices (this was finalized and adopted in June 2023).

After these interventions in 2022, prices began to recede, except in West Kazakhstan and Atyrau oblasts, where they moved up to more closely reflect national-level prices.[123] As a consequence, vehicle switching to LPGs from gasoline continued to be strong because of the relatively low LPG prices and robust economic growth. By 2023, the government began to cautiously move to raise prices again, increasing the regulated LPG ceiling price outside of exchanges to 40.32 thousand tenge/ton (excluding VAT) for the period from 1 July 2023 to 30 June 2024. Similarly, on the sidelines of a government meeting on 29 August 2023, Energy Minister Almasadam Satkaliev announced a plan to increase the prices received by producers of LPGs "to at least the [break-even] cost-price level, within three years."[124]

With respect to exchange trading, the plans to re-introduce the system were pushed back to 2025. Meanwhile, the government refined the mechanism for LPGs allocations and continued direct LPGs wholesale and retail price regulation. The Ministry of Energy assumed the responsibility for setting ceiling prices for retail sales of LPG as part of the supply plan outside commodity exchanges; previously this function was with KREM.

116 The main LPGs trading platforms were the ETS and CCE exchanges, as well as the Alan-Trade electronic trading platform.

117 https://adilet.zan.kz/rus/docs/V2300032904.

118 https://adilet.zan.kz/rus/docs/V2200028710.

119 https://adilet.zan.kz/rus/docs/V2200026409#z3.

120 On 19 July 2022 the LPGs exchange trading rules were added to the order "On the Approval of the Model Rules of Exchange Trading." https://adilet.zan.kz/rus/docs/V2200028847#z15.

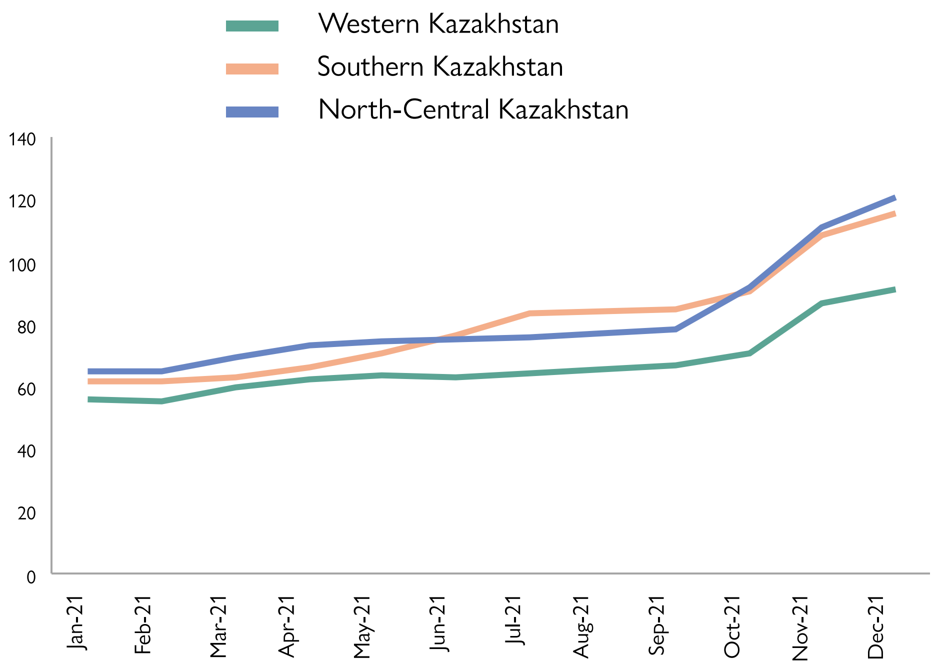
121 TCO and Nostrum are excluded from this process, as they operate under PSAs.

122 https://adilet.zan.kz/rus/docs/V2200028847#z8.

123 Although LPG prices in West Kazakhstan Oblast and Atyrau Oblast have historically been lower than in other parts of the country (reflecting their proximity to LPG production sites), in 2022 prices in western Kazakhstan converged with prices in the southern and north-central parts of the country.

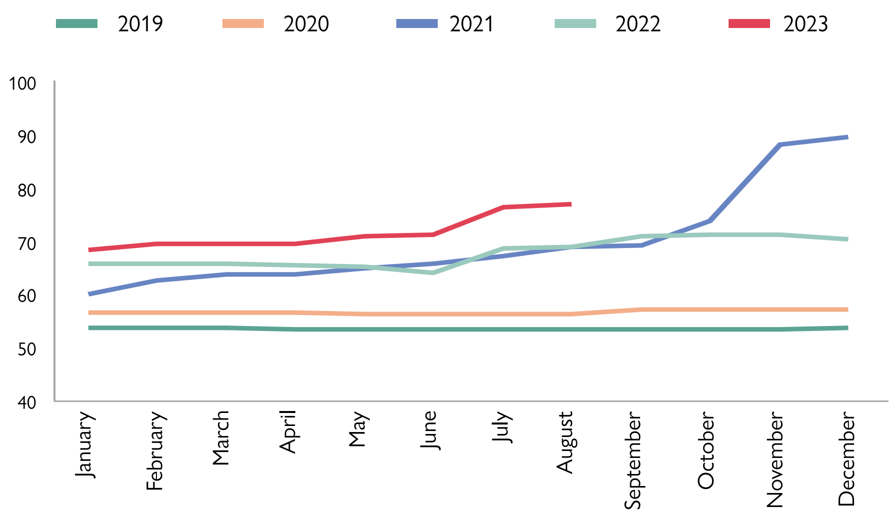
124 https://kapital.kz/economic/118620/stoimost-szhizhennogo-neftyanogo-gaza-budut-postepenno-povyshat-min-energo.html.

Figure 6.34 LPG prices at gas filling stations by region in 2021 (tenge per liter)



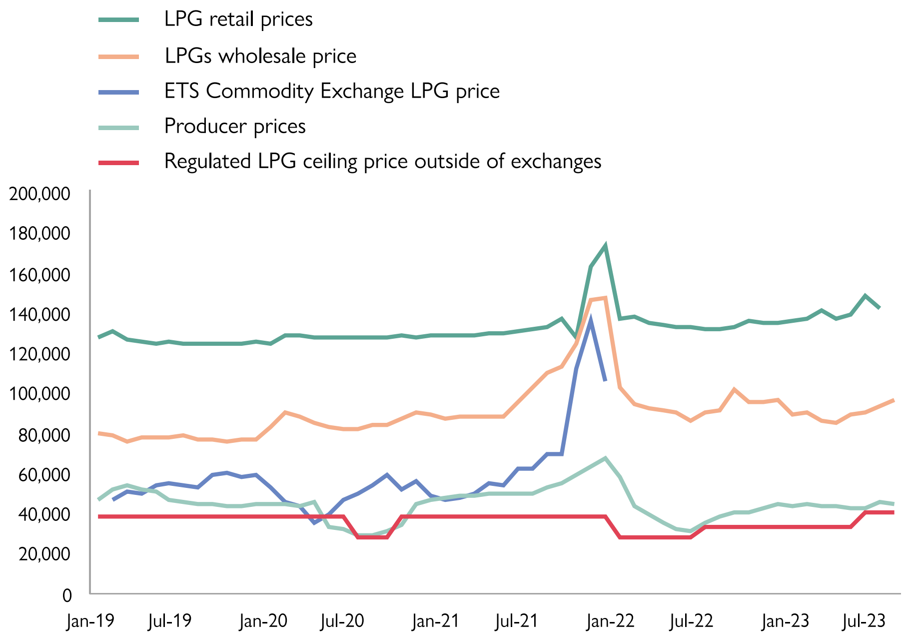
Source: S&P Global Commodity Insights, Situational-Analytical Center of the Fuel & Energy Complex of RK.

Figure 6.35 Average LPG retail prices in Kazakhstan by month in 2019–23 (tenge per liter)



Source: S&P Global Commodity Insights, Kazakhstan's Bureau of National Statistics.

Figure 6.36 Average monthly LPG prices in Kazakhstan (tenge per ton)



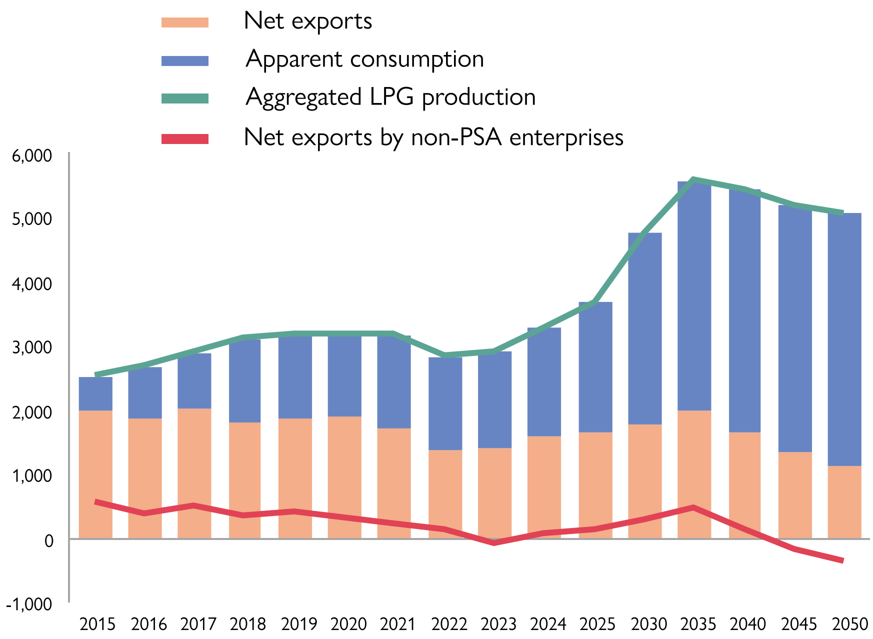
Notes: ETS Commodity Exchange prices and regulated LPG prices are reported ex-VAT.
Source: S&P Global, Kazakhstan's Bureau of National Statistics, ETS Commodity Exchange, Ministry of Energy of Kazakhstan.

6.14.4 Outlook for Kazakhstan's LPG balance

Production outlook. In our base-case outlook, Kazakhstan's LPG production almost doubles, reaching almost 5.7 MMt by 2035 but then slowly declines thereafter to about 5.1 MMt in 2050 (see Figure 6.37 Kazakhstan's LPG balance to 2050). This is equivalent to an annual average rate of growth of approximately 4.1% during 2022-35, and 2.1% over the entire 2022-50 period. Key drivers for higher LPG output are the new petrochemical operations planned for this period, and their substantial demand for feedstock. Many of the new petrochemical operations will be producing LPG feedstock from their own separation facilities (for example, a new gas separation unit for the integrated gas-chemical complex in Atyrau [Phase 2]). LPG production by petrochemical operations is expected to grow quite rapidly, reaching about 2.1 MMt/y in 2035 (see Table 6.17 Kazakhstan's major LPG-based petrochemical projects). In contrast, LPG output by GPZs (from associated gas processing) is expected to grow slightly, but it is tied to the amount of gas being processed, so it resembles the trajectory of commercial gas production in the country. Finally, LPG output from refineries is expected to increase only moderately, expanding with refinery throughput.

Given that much of petrochemical operations will meet their own needs from their own production, while aggregate LPG demand elsewhere is expected to remain fairly flat (increasing in some sectors like transportation, while declining in others, such as electric power and residences receiving piped gas) (see below), Kazakhstan is expected to remain a sizable exporter of LPGs (~2.0 MMt/y in 2035 and ~1.2 MMt/y in 2050). However, given that some LPGs producers, most notably TCO and Zhaikmunay, are likely to continue to export because of a continued difference in prices between domestic markets and global export markets, it should not be ruled out that imports may become more significant in the future.

Figure 6.37 Kazakhstan's LPG balance to 2050 (thousand tons per year)



Source: S&P Global Commodity Insights.

Table 6.17 Kazakhstan's major LPG-based petrochemical projects

	Polypropylene project*	Polyethylene project	Gas separation installation	Butadiene project
Project description	Integrated gas and chemical complex in Atyrau (Phase 1)	Integrated gas and chemical complex in Atyrau (Phase 2)	Integrated gas and chemical complex in Atyrau (Phase 2)	Butadiene plant in Atyrau
Owner	KPI	KMG PetroChem LLP; SIBUR; Sinopec	KMG PetroChem LLP	KMG and Tatneft
Product output	0.5 MMt/y polypropylene	1.25 MMt/y polyethylene	1.6 MMt/y ethane; 0.36 MMt/y propane	0.186 MMt/y butadiene sent to tire plant in Karaganda
Feedstock	TCO to supply up to 550,000 tons/y of propane to KPI Inc.	Extracted propane/ butane mix from the Atyrau Phase 2 GSU	Associated gas from TCO's Tengiz field	380,000 tons/y of butane from TCO

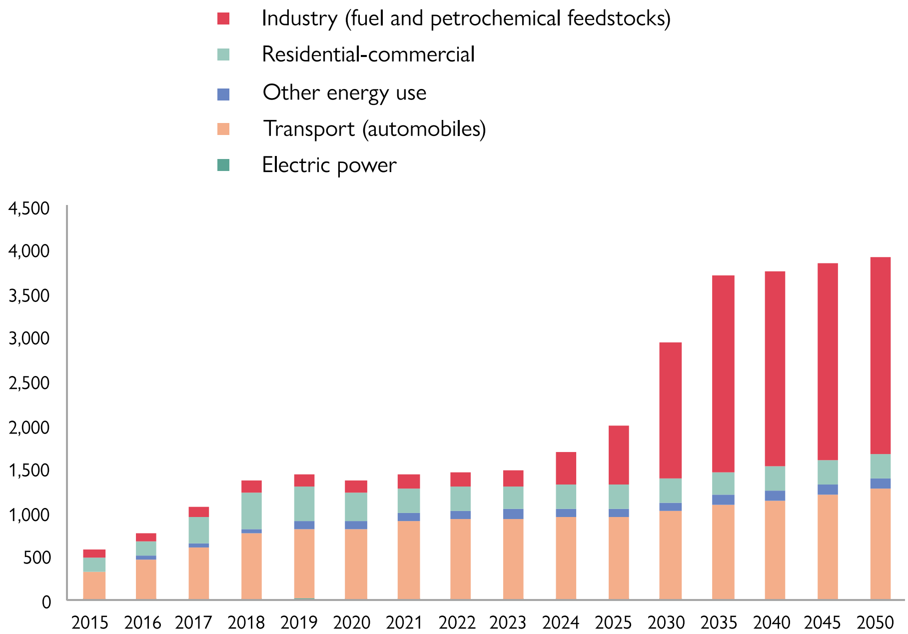
Notes: For additional details on these projects, see Section 6.10. *This project launched operations in late 2022.
Sources: S&P Global Commodity Insights.

Consumption outlook. In our base-case outlook, Kazakhstan's LPG consumption in 2035 more than doubles from 2022 levels, reaching 3.6 MMt, with the emerging petrochemical sector driving much of the growth. Subsequently, consumption growth moderates somewhat, rising by only about 10%, to reach 3.9 MMt in 2050. Despite the robust growth in demand, projected to average roughly 7% annually to 2035 (and 3.6% on average during 2022-50), domestic production should be sufficient to cover consumption (in aggregate). Some LPG exports occurring under PSAs could be accessed at export-parity prices as necessary to meet demand. Some LPG volumes also could be available for import from Russia (or other neighboring countries that currently export like Turkmenistan) if necessary (although this would also be at export-parity prices).[125]

The petrochemical sector will be the largest incremental source of domestic demand, rising to 1.9 MMt in 2035, assuming all planned projects launch (albeit with some delays from announced schedules), and then increasing more slowly to 2.1 MMt by 2050 (see Figure 6.38 Kazakhstan's LPG demand outlook by sector to 2050).[126] Consumption of LPGs outside of petrochemicals is likely to remain fairly flat due to a number of countervailing trends across the different sectors:

- With the build-out of natural gas pipelines, LPG can be gradually replaced by piped gas in households, the commercial sector, and eventually in industry for their fuel needs, such as in North-Central Kazakhstan, thus reducing demand for LPGs.
- LPG use in motor vehicles is projected to grow, albeit at a slowing pace with increased penetration. But growth is expected to be stronger in the near to medium term from fuel switching, especially if LPG prices continue to be more heavily regulated while gasoline prices rise.
- Other possibilities for increasing domestic consumption of LPGs could emerge, including small-scale electric power generation, especially near sites of LPG production.

Figure 6.38 Kazakhstan's LPG demand outlook by sector to 2050 (thousand tons)



Source: S&P Global Commodity Insights.

125 We project that Russia's sizable LPG exports are likely to contract during the period to 2035, due to broader constraints emerging on Russian oil and gas production following the military conflict in Ukraine. However, Kazakhstan should still be able to import some Russian LPG volumes (in the event of a deficit), as long as it can compete on price with export markets.

126 Most of the LPG consumption by industry falls within the petrochemicals sector.

6.15 High-Level Takeaways

- The government of Kazakhstan is commended for moving forward with several policy amendments that improve gas market functionality. The next steps should be keeping track and evaluating the success generated by new legislation and adjusting it as necessary. For example, has the adoption of the Improved Model Contract resulted in significant interest and signed contracts from IOCs? Is the new price for new gas sufficient to cover expenses of the new production? In assessing the success of IMC, it is important to keep in mind the broader international context where Kazakhstan competes for investments with other countries.
- Kazakhstan's government increased gas prices to end-consumers in 2023, but they are still not high enough to cover the costs throughout the value chain. The policy momentum to gradually increase prices, albeit at a differentiated pace for different groups of consumers, should allow prices to more quickly reach cost recovery levels and then economic levels, and should help encourage consumers to use natural gas more efficiently.
- Given the impeding deadline for creating a common gas market in the EAEU by 2025, and the resultant gas pricing harmonization with Russia, prices in western Kazakhstan should be set on a trajectory that will approach 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.
- Given the primary goal of increasing the availability of sales gas through increased gas processing, it is surprising that *incentives for new gas processing* have not been more fully incorporated into the new legislation (e.g., Improved Model Contract). It probably will be necessary to provide economic incentives for expansion of gas processing as well as upstream E&P to stimulate growth in commercial gas volumes. At the very least it will be important to send clear signals that investors will be protected against arbitrary unilateral decisions by the state.
- LPG pricing has proven to be a sensitive and sometimes contentious issue for Kazakhstan, with rapid price rises in 2021 prompting the outbreak of political unrest in January 2022. After some retrenchment, by 2023, the government began to cautiously raise prices again, by increasing the regulated LPG ceiling price outside of exchanges. We support Energy Minister Satkaliev's plan to increase producer prices to at least the [break-even] cost price level within the next three years and a gradual reintroduction of further liberalization policies. These and similar measures will both incentivize production and reduce the threat of unauthorized demand through "grey" exports.

CHAPTER 7

COAL INDUSTRY

7. COAL INDUSTRY

AVANTGARDE ADVISORY

Coal is still of crucial importance to the global energy sector despite the development of renewable energy and the implementation of energy transition policies in developed economies, with about 37% of the world's electricity produced from coal and 70% of the world's steel production using coal.

Coal, like natural gas, plays an important role in building renewable energy infrastructure and supporting renewables in the grid. Coal prices, its availability and abundance are critical to the social development of developing countries. The energy crisis and natural gas supply problems in 2022 have shown that coal remains a stabilizing factor in energy markets.

The unprecedented increase in coal prices in 2022 and ongoing strong demand in the EU has significantly increased opportunities for Kazakh coal exports. Coal shipment to European countries partially helped the EU to offset the loss of coal exports from Russia. Kazakhstan exported 3888.16 thousand by 3.9 million tons of coal to the EU in 2022, and in the future it is planned to increase the volume of shipments to the EU.

Investment is needed to develop the industry, which will pay off when exports expand and price restrictions are partially lifted on the domestic market.

7.1 Key points

- Until stable energy generation technologies (e.g. thermonuclear energy) or creation of fundamentally new energy storage technologies appear, coal cannot be excluded from the global energy balance;
- Coal allows Kazakhstan's industry to maintain competitiveness due to one of the lowest costs of electricity generated by coal-fired power plants;
- The policy of restraining the coal prices in the domestic market allows to maintain low cost of energy but limits the possibility of investment in the development of coal mines;
- According to the World Coal Association, it is possible to reduce carbon dioxide emissions by 2 billion tons of CO_2 by upgrading existing coal-fired power plants to the best available technologies. Kazakhstan can also reduce greenhouse gas emissions by modernizing coal-fired power plants;
- Increased production of high-calorie Shubarkol coal allows for increased exports to non-CIS countries. In addition to Russia, promising export destinations are: Turkey, European countries and Uzbekistan;
- Establishment of new semi-coke production facilities will reduce the high share of semi-coke imports from Russia used in the metallurgical industry;
- Implementation of the best available technologies at coal mining enterprises will reduce the cost of field development and the environmental impact of the coal mining industry.

7.2 Industry regulation

Kazakhstan's coal industry is currently the main source of energy for the national economy, accounting for more than 55% of primary energy consumption and 68% of electricity generation in 2022. Almost the entire range of coal production is represented in Kazakhstan - from lignite and sub-bituminous coal for power generation to metallurgical coal and coking coal for blast furnaces.

The coal industry, unlike the oil and gas industry, does not have a "state company" or "national operator", but about 40% of production is accounted for by the largest coal producer in Bogatyr Komir LLP, owned by the state-owned JSC "Samruk-energy" and the Russian company "RUSAL".

The mining industry is regulated under the Code of the Republic of Kazakhstan "On Subsoil and Subsoil Use" and is predominantly controlled by the Ministry of Industry and Infrastructural Development.

While there is no direct regulation of prices in the domestic coal market, in Kazakhstan the state actually restrains the growth of coal prices. The mechanism of restraint is carried out by monitoring the prices of market players, which according to the legislation can be recognized as dominant.[1] Even not the largest coal mining companies can be defined as dominant participants of the regional coal market. According to the antimonopoly legislation, unjustified price growth of coal mining companies may be recognized as abuse and direct violation of antimonopoly legislation.

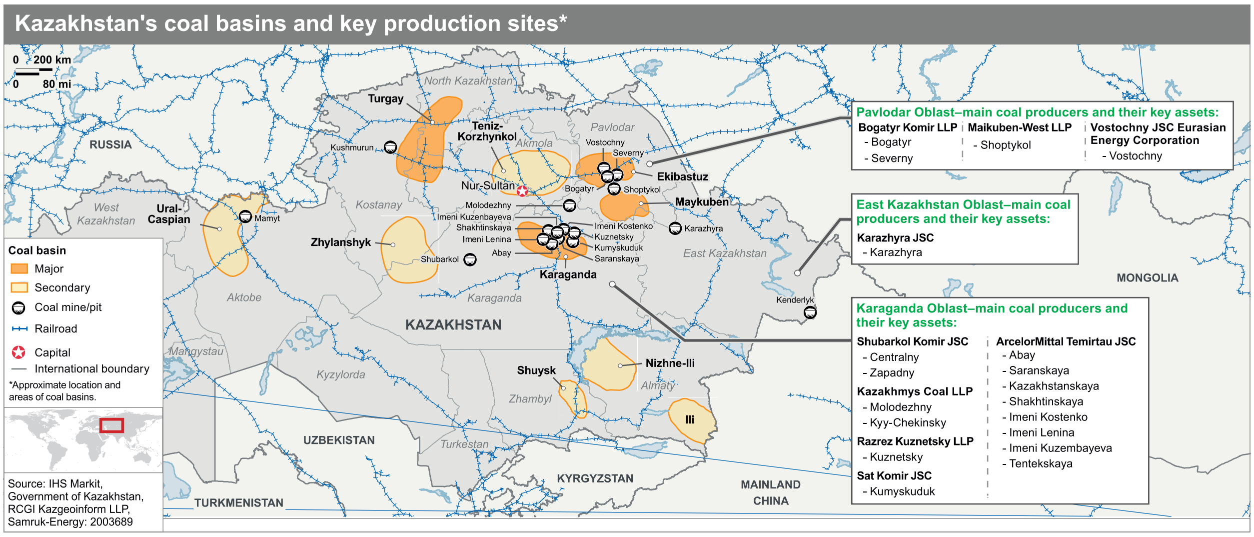
As a result of restraining the growth of the cost of coal shipment to consumers of the domestic market may lag behind the inflation rate. A number of enterprises ship coal to domestic market consumers at prices even below the cost of production.

The government is currently considering the introduction of price regulation in the power-generating coal market. This measure may have negative consequences for investments in modernization and upgrade of coal mining enterprises.

In terms of taxation, the rent tax on coal exports, which was in effect earlier, has been replaced by the mineral extraction tax (MET). In case of using power-generating coal to produce electrical or thermal energy or to process coal (hard coal (except for coking coal and anthracite), brown coal, oil shale), a reduction factor of 0.01 is applied to the established rate.

1 According to the Entrepreneurial Code of the Republic of Kazakhstan: The position of a market entity whose share in the relevant product market is thirty-five percent or more is recognized as dominant.

Figure 7.1 Kazakhstan's coal basins



7.3 Coal basins reserves

Having rich coal reserves, Kazakhstan is one of the world leaders in coal production and consumption. The State Balance Sheet lists 49 coal deposits and coal-bearing areas. According to available data, coal reserves under categories A+B+C1 (which is equivalent to the category of "proven and probable" reserves) amount to 29.3 billion tons. Kazakhstan ranks tenth in the world in terms of coal reserves, which will last for more than 250 years at current production rates. The largest coal basins - Ekibastuz (10.1 billion tons), Karaganda (7.0 billion tons) and Turgai (5.9 billion tons) - are located in central and northern Kazakhstan.

Ekibastuz Basin coal mines are particularly notable for their low production costs: the coal beds are thick and close to the surface, which facilitates the use of traditional open-pit mining methods. However, coals of Ekibastuz basin, containing 45.8% of Kazakhstan's power generating coal reserves, are characterized by very high ash content (42-44%), and the ash is highly abrasive, which leads to increased wear of boiler heating surfaces when burning coal in dusty state. Coals of Ekibastuz basin belong to low-enriched coals, which limits the possibility of its enrichment by traditional methods.

Reserves of coals suitable for coking are concentrated mainly in the Karaganda basin (90.5%). Most of the coals of the Karaganda basin due to their high technological properties are classified as high quality raw materials for the coke-chemical industry.

Unlike coals of Ekibastuz basin, coal of Shubarkol deposit is characterized by lower ash content (5-15%) and sulfur content (0.5%) and high calorific value (5,600 kcal/kg).

7.4 Coal extraction

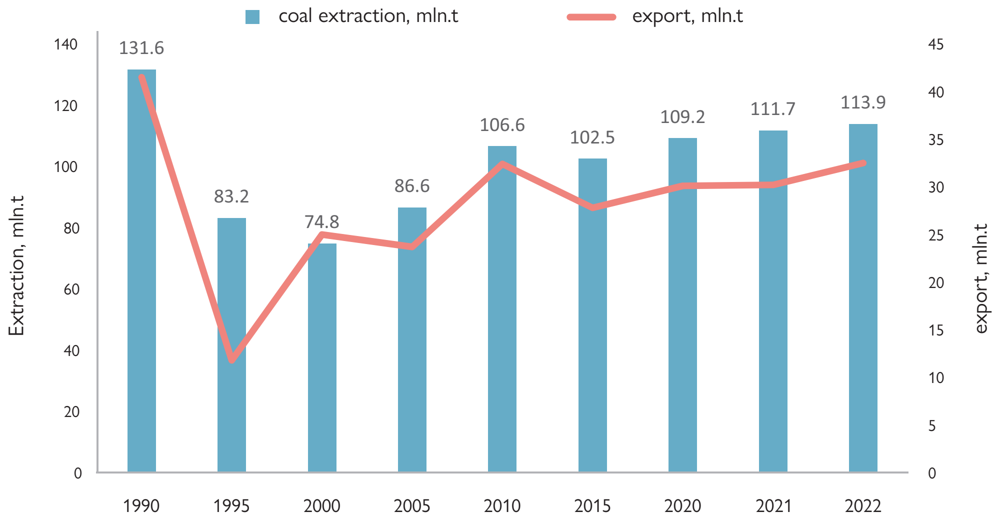
In 2022, Kazakhstan ranked ninth in the world in terms of coal production with a cumulative production of 113.9 million tons, up 2% from the 2021 level. The 2022 production level is the highest production level in the last ten years. 70-75% of Kazakhstan's coal production is focused on the domestic market, but due to the energy crisis in Europe, demand for coal has increased significantly, however, logistical problems have arisen.

According to the Ministry of Industry and Infrastructure Development, there are 25 coal mining enterprises in the country, with three quarters of national production concentrated in four enterprises: Bogatyr Komir LLP, Eurasian Energy Corporation (ERG), Shubarkol Komir JSC and ArcelorMittal Temirtau JSC.

The largest coal producer in Kazakhstan is Bogatyr Komir LLP, which is developing the giant Bogatyr open pit mine in the Ekibastuz basin. In 2022, the company's production volume amounted to 42.5 million tons or about 40% of the national production. In 2022, the company introduced a new cyclic-flow technology (CFT), which enabled the transition from coal transportation by rail to conveyor transportation. The transition to the cyclic-flow technology increased the degree of averaging of coal from different-quality coal beds using crushing equipment and will ensure the stability of the quality of shipped coal due to the automation of control processes. The project increased the design capacity of the Bogatyr open pit mine by 8 million tons and significantly reduced dust generation and operating costs.

The second largest coal producer is Eurasian Resources Group (ERG), which accounts for about a quarter of the country's total coal production through two holdings: Eurasian Energy Corporation JSC (EEC) and Shubarkol Komir JSC. Slightly more than 1/5 of production is accounted for by three other producers:

Figure 7.2 Coal extraction in Kazakhstan



Source: Office for National Statistics.

the Coal Department of ArcelorMittal Temirtau JSC, Kazakhmys Coal LLP and Maikuben West LLP. Karazhyra JSC, which operates in the East Kazakhstan region, produces around 6% nationwide.

In 2017 - 2022, large coal mining companies increased production by 8%, at the same time the companies have reached their design capacity and further increase in production volumes will be associated with significant investments. It is impossible to attract investments for coal projects from a wide range of international financial organizations due to restrictions imposed on investments in hydrocarbon fuel production.

In recent years, the Kazakhstan industry has seen a trend towards the introduction of dry coal preparation plants. The pilot introduction of this technology began in the 2010s at the Karazhyra deposit, now a number of coal mining companies are planning to introduce dry coal preparation technology, including the construction of a dry coal preparation complex at the Bogatyr deposit at the Severny open pit mine with a capacity of up to 2 million tons of coal per year.

Large coal mines could increase coal production by 2030 by 12 million tons, out of which:

- 4 million tons of increased coal production by Bogatyr-Komir LLP to supply coal to the planned new coal-fired power units;
- 2 million tons of increased production at Maikuben West JSC will be directed to the domestic market and increased supplies to Russia and Uzbekistan;
- 2 million tons of coal production at JSC Karazhyra will probably be directed to the domestic market;
- 2.2 million tons of coal production at JSC Karazhyra will probably be directed to the domestic market;
- it is also planned to increase production at Shubarkol Premium JSC by 2 million tons.

An important factor affecting the development of the industry is prices in the domestic market and the policy of price restraint, which affects investment in the industry and modernization of production. Given the transition to BAT and the implementation of environmental protection measures, a tangible price increase will be required. Unlike the prices of other fuels, coal prices in Kazakhstan are not directly regulated. However, the government retains oversight over pricing and trading in the coal industry.

In Kazakhstan, the transportation of utility coal by railway infrastructure is also subsidized, so price restraint occurs both at the production level and at the level of transportation costs.

The National Energy Report 2021 gave a forecast for coal production until 2050: a decrease in production to 69 million tons by 2050 and a decrease in consumption to 56 million tons in 2050. This forecast can be considered as one of the options for the development of the sector but in general the situation with coal consumption depends on the availability and prices of natural gas and the decision on the construction of nuclear power plant, subject to the referendum outcome referendum in the near future.

7.5 Domestic coal consumption

Coal plays a critical role in Kazakhstan's economy: in 2022, it still accounted for 52% of the country's total primary energy consumption.

The main consumers of coal are coal-fired power plants, whose consumption in 2022 accounted for 57.5 million tons of coal, while boiler houses consumed 6.9 million tons of coal. Industrial sector coal consumption amounted to 6.0 million tons of coal, the municipal sector and population accounted for 11.0 million tons of coal.

Coal from the Ekibastuz basin is the main source for 10.9 GW, 1.9 GW of coal-fired power plants operate on coal from the Karaganda basin, and another 0.6 GW of coal-fired power plants operate on coal from the Karazhira deposit.

Despite the fact that Kazakhstan continues to implement the gasification program and is actively introducing RES, coal will

Table 7.1 Coal production at large deposits, million tons

	2018	2019	2020	2021	2022
Bogatyr-Komir	44.9	44.9	43.3	44.6	42.5
EEC (Vostochny open pit)	17.1	15.5	17.4	17.2	17.4
Shubarkol Komir	11.6	12.0	11.5	12.7	12.5
ArcelorMittal Temirtau	10.0	12.0	11.5	12,7	12.5
Karazhyra	8.1	8.2	8.0	7.8	8.4
Maikuben West	4.0	4.3	4.1	3.8	4.1
Shubarkol Premium	1.0	1.2	1.3	1.7	3.0

Source: company data.

remain a significant source of energy for the economy until 2040, especially in electricity generation.

Until 2035, despite the conversion of Almaty CHPPs to natural gas, there is a plan to build four new coal-fired units (GRES) with a total capacity of 2136 MW and a coal-fired CHPP in Kokshetau with a capacity of 240 MW as well as the expansion of a number of coal-fired CHPPs.

As a result, coal consumption by the energy sector may increase by 5 million tons. Increase in the design capacity of Bogatyr mine allows to fully offset this increase in coal consumption.

Commissioning of new coal-fired capacity will be accompanied by gradual decommissioning of GRES power units with a high level of wear and tear and long service life, besides, in case of NPP construction, coal-fired generation at GRES will be gradually displaced.

After 2035, the growth of coal capacity will be offset by the gradual retirement of coal-fired generation with long equipment service life. The peak of domestic coal consumption is forecasted until 2035, then the consumption will decrease, which will depend more on the commissioning of NPP capacities.

In industry, especially in the mining and metallurgical sector, coal consumption will decrease, so the implementation of the "Hydropolymet" project at the Ridder metallurgical plant will lead to a significant reduction in the consumption of coal and coal coke.

Kazakhstan's development of direct iron reduction technologies using natural gas will also reduce coal consumption. For example, SSGPO JSC is implementing a project in the city of Rudny to build a plant for direct reduction of iron from iron ore raw materials, with a total capacity of 1.8 million tons of metal per year.

Gradual gasification of regions and population will affect the reduction of coal consumption, however, the high cost of natural gas compared to coal will be the main deterrent to the substitution of coal with natural gas in the housing and utilities sector.

An important factor of the domestic coal market is the actual restraint of coal sales prices from mining enterprises and cross-subsidization of railroad transportation of coal. If measures to administratively restrain coal prices are lifted, the price of coal on the domestic market could increase by an estimated 30-40%. It is unlikely that coal price regulation and cross-subsidization of coal transportation at the expense of other commodities will be terminated in the coming years.

The Agency for the Protection and Development of Competition in the Republic of Kazakhstan regularly inspects any unusual coal price spikes for residential consumers. The government periodically discusses direct regulation of power generating coal prices on the domestic market, but this measure would have negative consequences for the development of the coal industry.

7.6 *Coal export*

Although Kazakhstan has impressive coal reserves, most of coal is characterized by high moisture and ash content, which significantly limits its export opportunities.

The main export markets (China and EU) have ash and sulphur content requirements, so most of the coal mined in Kazakhstan is not competitive on the global market. Most coal is exported to Russia from the Ekibastuz basin, as coal-fired power plants in the South Urals and Western Siberia were designed to burn Ekibastuz coal.

Over the past decade, Kazakhstan has exported about a quarter of its annual production but this figure has been gradually declining. In 2010, exports accounted for about 31% of production, but its share fell to about 25% in the middle of the decade, and from 2018 to only 20-21%. However, in 2020, coal exports rose to 28% of production.

The export structure has changed over the past five years, while Russia used to account for 78-80% of Kazakhstan's coal exports, Russia's share has fallen to 70% in 2021. Coal exports to Uzbekistan increased to 1.2 million tons (5% of exports), and the share of exports to non-CIS countries increased to 18% (5.5 million tons), the increase in exports was to Switzerland (up to 4.3 million tons - 14%).

The situation with coal exports has changed significantly in 2022, as a result of the energy crisis, the volume of coal exports to non-CIS countries increased to 9.3 million tons, the largest increase occurred in Switzerland (up to 6 million tons), Poland, Cyprus, Turkey and Belgium.

Table 7.2 Coal exports by country 2017 - 2022, mln tons

		2017	2018	2019	2020	2021	2022
	H ard coal (total), incl.	2 7526	2 4170	2 3143	2 6552	2 6617	2 9710
EA EU	Russia	21292	19734	19777	19594	18913	18972
	Kyrgyzstan	1080	1033	754	958	486	450
	Belarus	160	239	389	951	495	450
CIS	Uzbekistan	65	113	121	339	412	488
	Ukraine	404	371	790	905	793	90
Other	China	0	0	39	173	86	15
	Belguim	0	0	0	0	9,8	226
	Bulgaria	0	0	0	0	23,3	140
	Latvia	0	0	12	2	0,0	735
	Poland	0	41	22	53	156	1530
	Great Britain	18	0	0	11	166	30
	Turkey	0	0	11	5	541	856
	Cyprus	181	190.5	447	0,0	30,0	753
	Switzerland[2]	761	1390	773	3557	4351	4391
	Finland	3450	1034	0	0	0	0
	Estonia	0	0	0	0	0	266
	Other	114	24	8	5	156	320
	Lignite (total), incl.	2231	2757	2693	3564	3587	2790
EAEU	Russia	1824	1983	2249	1956	2338	2000
	Kyrgyzstan	11	3	15	4	15	0
	Belarus	0	105	45	0	0	0
CIS	Uzbekistan	395	666	384	1604	1233	789
	Other	1	1	0	0	1	1

Source: Ministry of Finance of the Republic of Kazakhstan, Eurasian Economic Commission.

The outlook for the European coal market is very significant, with expected demand growth exceeding 40 million tons, while the price level has been maintained at a high level since the outbreak of military actions in Ukraine.

Due to the conflict in Ukraine and the subsequent natural gas supply crisis, there was a record increase in coal prices in 2022. Thus, the key quotation for of API 2 coal imported to Northwest Europe reached an all-time high on March 08, 2022 (438.35 $/t), reflecting more of a panic in the market. By autumn the situation stabilized and a decline was achieved at 267 $/t on October 28, 2022.

The increase in coal demand during winter 2022 and early 2023 in European countries has of course led to an increase in the cost of coal, but in the horizon of the next few years, stabilization in the energy market will be achieved gradually, which will put downward pressure on the coal market.

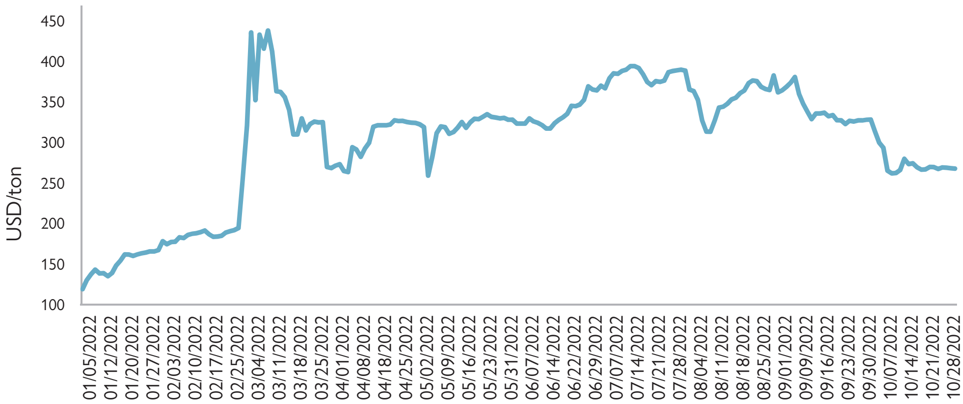
According to McCloskey forecasts, the decrease in coal prices in the European market will be achieved within two years due to stabilization of energy resources supplies. Stabilization of supplies of energy resources even if the military and political crisis in Ukraine drags on, will be achieved by filling coal capacities in the EU and gradually increasing coal imports, including from the USA.

Even with lower prices and stabilization of the EU market, coal supplies from Kazakhstan look very promising. Companies producing Shubarkol coal (Shubarkol Komir JSC and Shubarkol Premium JSC) have already increased coal production by 3 million tons in five years, and will increase production by 4 million tons in the next three years. At the same time, transit through the territory of the Russian Federation is a barrier in this regard, which does not allow to fully realize the export potential of Kazakhstan's coal industry in this direction.

Turkey, which has plans to build coal-fired power plants and imports up to 58% of its domestic coal demand (about 40 million

2 While hydropower is still one of the most important domestic energy suppliers in the Swiss electricity mix, there are no longer any coal-fired power plants.

Figure 7.3 Change in the API2 quotation from January to October 2022.



Source: investing.com, Argus Media.

tons), is also a promising export destination. In addition to the energy sector, Turkey's cement industry is a major consumer of coal - the country is the 7th largest cement producer in the world.

Turkey is one of the largest importers of coal, in view of the plans to develop coal energy, cement industry and other consumers under the current environmental legislation it is possible to forecast further increase of Kazakhstan coal exports to Turkey.

7.7 Coal transportation

Tariffs for railroad transportation in Kazakhstan are regulated by the Committee for Regulation of Natural Monopolies of the Ministry of National Economy of the Republic of Kazakhstan. Tariffs for coal are usually set below the average for all other cargoes transported by rail, taking into account its significant share (25%) in the total volume of railroad transportation and its status as a socially important commodity.

The tariff for railroad transportation consists of three components: mainline railroad network services, locomotive traction services and provision of freight cars (containers). Railway network services are regulated and differentiated by track sections (with a division into electrified and non-electrified) from 2021, while the regulation of freight car services was abolished in 2017. In turn, regulation of locomotive traction services is retained, but differentiated tariffs for different types of traction (divided into diesel and electric locomotive) and fuel are in place as of 2021. According to Kazakhstan's national railway company Kazakhstan Temir Zholy (KTZ), the tariff for locomotive traction using oil products (diesel fuel) is 4.6 times higher than the same tariff for coal.

In December 2020, the Committee for the Regulation of Natural Monopolies approved new tariffs for freight transportation by rail for 2021-2025, indicating that the average tariff will increase by 13% in 2021, while tariffs for coal and grain will only increase by 4-6% (essentially in line with the inflation rate forecast). In addition, KTZ has officially separated freight operations from passenger transportation, and cross-subsidization of passenger transportation is now explicitly outlined.

7.8 Accidents at coal mines

The coal of the Karaganda basin is characterized by high methane content, and mining is accompanied by constant accidents with serious injuries and deaths of miners. Despite the legal requirement to degasify coal beds prior to mining, accidents with human casualties occur annually at ArcelorMittal Temirtau JSC (AMT) coal mines. Thus, on August 17, 2023 at the mine "Kazakhstanskaya", owned by AMT there was a fire at the time when 227 people were underground. The accident at the "Kazakhstanskaya" mine killed five people, and in 2022 the accident at the "Lenin" mine killed five people, in 2021 the accident at the "Abayskaya" mine claimed the lives of 6 miners.

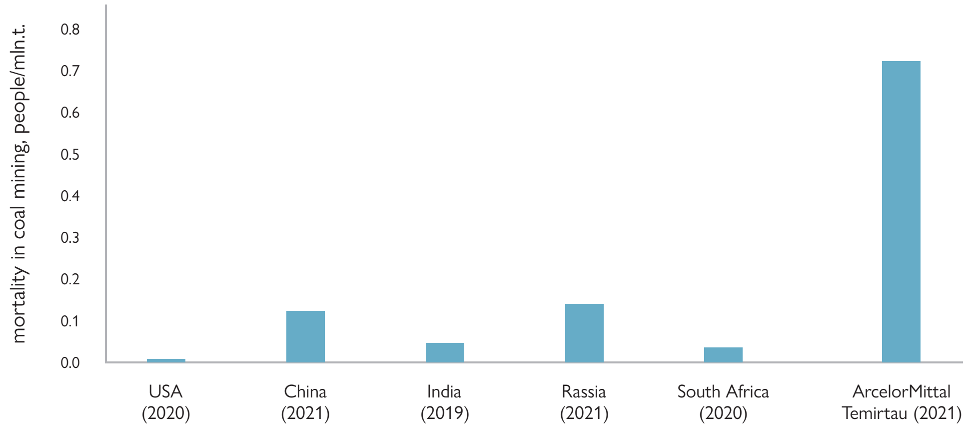
For comparison, according to the US Department of Labor, mining about 590 million tons of coal in 2020 killed 5 miners, and in Kazakhstan 6 miners died in ArcelorMitall Termirtau alone mining 8 million tons of coal in 2022.

The tragedies at the mines are not an exception in the company's practice, according to the parliamentarians, more than 100 people have already died in the 15 years of ArcelorMitall Termirtau's operations.

According to Basin V. B., deputy akim of Karaganda region: - "Investments to replace equipment, to upgrade equipment, to decommission equipment that has exhausted its fleet life, are very few. In the last three years, investments have averaged 100 billion tenge (about $210 million). However, taking into account the size of the plant, its composition, and its coal department - 8 mines, including surface plants, and the ore department with 4 mines keeping in mind problems we have today, this is not enough" [1],

It is characteristic that the data of national statistics shows a significant reduction in occupational mortality in Kazakhstan, but

Figure 7.4 Mortality in coal mining, deaths per 1 million tons of coal production



Source: Energyprom.kz

it is not the case with ATM company - the mortality rate reaches 4 people per year for every 10 thousand employees.

As a result of ongoing accidents at AMT enterprises, the President of Kazakhstan K.-J. Tokayev questioned further operation of this investor in Kazakhstan. Continuous accidents at the above mentioned enterprises owned by the foreign company indicate a serious violation of its investment and other obligations with corresponding consequences for further operation in the Kazakhstan market.

Currently, the Government of Kazakhstan is negotiating with the shareholders of ArcelorMittal the termination of their activities in the country and the sale of their asset.

7.9 Development of the coal industry in Kazakhstan

Increase in coal production is also accompanied by technological development of coal mining enterprises and creation of production facilities with deep coal processing and development of the domestic market of coal products, in particular coal semi-coke (special coke).

In Kazakhstan, coking coal is used to produce coke, which is then used in the production of steel and cast iron. Coke is also widely used in the production of other metals, including aluminum and copper. All coke produced in Kazakhstan is fully consumed by ArcelorMittal Temirtau's metallurgical operations.

Main volume of semi-coke[2] is consumed in the domestic market, while such enterprises as Aksu Ferroalloy Plant JSC (Pavlodar region), Aktobe Ferroalloy Plant JSC (Aktobe region), Kazzinc LLP (East Kazakhstan region) import the main volume of semi-coke from Russia.

Russia is the key supplier of semi-coke to Kazakhstan, however, due to the tightening of environmental requirements in China since 2020 the production of semi-coke is reduced and imports from Russia will increase. Russian producers benefit more from the Chinese and Indian markets than supplies to Kazakhstan, so supplies to Kazakhstan are gradually decreasing from 2020.

The main producer of semi-coke used in the metallurgical industry is Shubarkol Komir JSC, which produced 212.5 thousand tons of semi-coke in 2020. By 2024, Shubarkol Komir JSC plans to build another plant in Karaganda region to produce semi-coke with a design capacity of 400 thousand tons per year and 70 thousand tons of coal tar and oil per year, obtained from coal of Shubarkol deposit. It is also planned to launch Temir Coke LLP with a design capacity of 43 thousand tons of semi-coke per year.

The increase in semi-coke production is promising and enables the Kazakh industry to fully switch to the use of its own products.

In terms of technological development, taking into account the plans for transition to BAT principles, it is currently recommended to consider the following options for the industry:

Dry coal preparation

Dry coal preparation technologies involve coal preparation without the use of water. Such plants include pneumatic, magnetic and electromagnetic coal preparation equipment [3].

The principle of operation of the pneumatic coal preparation plant is separation of particles by density in the upward air flow. During the separation process the particles are separated according to the set density boundary. The plant allows to separate waste rock and high ash coal from low ash coal. Pneumatic coal preparation plants can be quite compact, so in the future they can be installed directly at open-pit mines or in mines.

Dry coal preparation is applied at Karazhyra deposit at FGX-24A preparation complex (capacity of 240 tons/hour), which allowed to increase the production volume by 300-400 thousand tons of coal per year. Dry coal preparation unit is planned to be put into pilot operation at Bogatyr Komir LLP.

3 In Russia, 2 out of 62 large coal preparation plants operate on dry enrichment technology.

Conveyor transportation

Conveyor transportation is characterized by the lowest labor costs among all types of quarry transport.

Belt conveyors are used to transport coal, waste rock and rock from tunneling, stripping and mining faces along horizontal and inclined workings inside mining enterprises, to lift them to the surface and to further move them to the preparation plant, to the loading point of external transport or directly to the consumer, while rock is moved to the dump. It is a structure consisting of support legs, drive and tension drums, drive equipment, intermediate support rollers and a circular belt on which the loads are directly moved.

Implementation of conveyor lines allows to significantly reduce transportation costs and reduce pollutant emissions and dusting.

Digital model of the deposit

When developing coal deposits, an important factor is the availability of an up-to-date model of the deposit, its structure, dumps, embankments, etc.

To increase the efficiency of surveying works it makes sense to use geodetic UAVs for airborne surveying and appropriate software that allows to interpret the images and point cloud into a 3D model.

The use of UAVs in combination with modern software for modeling of coal mines will increase the efficiency of surveying works, reduce the time for their implementation, increase their frequency and accuracy. In turn, the availability of an up-to-date model of the mine, knowledge of its geology, structure and sizes of embankments and dumps will increase the efficiency of field development planning.

Industrial safety systems

Ensuring occupational and production safety is the most important task, as human life is the most important value.

Coal mining is associated with round-the-clock movement of a large number of machinery and transport, the latest technologies to ensure industrial safety are:

- Driver fatigue monitoring system allows to recognize the driver's concentration level, detect smoking, use of mobile devices while driving. If any abnormalities are detected, the system warns the driver and transmits information to the control center.
- Proximity warning system allows to minimize the risks of machinery collision with a person by signaling the proximity both to the person and to the driver or operator of the machinery.
- Surround-view cameras make it easier to maneuver quarry equipment and vehicles, and video recorders increase driver vigilance and allow for accurate identification of violations in the event of an incident.
- Personal GPS trackers with a SOS alarm button allow monitoring the location of people at the open pit, and enable employees to signal the control room in case of emergency cases threatening life and health.

In terms of technologies that can be attributed to BAT, it is recommended to consider the following areas:

Dust suppression

During mining operations, the impact of air and noise pollution on workers and local communities can be minimized by using modern mine planning techniques and special equipment.

Dust levels can be controlled by spraying water on roads, stockpiles and conveyors. Other steps can also be taken, including equipping drilling rigs with dust collection systems and acquiring additional land around the mine as a buffer zone. Trees planted in these buffer zones can also minimize the visual impact of mining operations on local communities. Bogatyr Komir LLP is taking measures to reduce dust emissions from its open pit mines, as they directly harm the health of employees. The company has installed a pilot fogging unit that converts drainage and fresh water into fog using a high-pressure pump. This mist then captures and precipitates coal dust, preventing it from spreading. The company plans to introduce six more of these units.

Wastewater treatment

Coal mining generates large quantities of pit water.

Enterprises are working to improve water management in an effort to reduce demand through efficiency, technology and the use of lower quality water and recycled water. Water pollution is controlled by carefully separating water runoff from undisturbed areas from water containing sediment or salt from mine workings. Treated wastewater and pit water can be discharged to surrounding water bodies, and it is possible to reuse it in processes such as dust suppression and irrigation of forest plantations.

There are mine management practices that can minimize acid mine drainage (AMD), and effective mine design can prevent water from entering acid-forming materials and help prevent AMD.

Methane emission control

While coal accounts for the majority of total GHG emissions and air emissions in Kazakhstan due to its combustion in the production of electricity and heat, coal mining (both mine and open pit) also has significant environmental impacts - including air quality, solid waste disposal and wastewater discharge. The most significant GHG emissions from coal mining are not so much related to fuel use at facilities, but rather to methane (CH_4) emissions that are released from mines and dumps during coal mining, transportation, and preparation.

Yet measuring methane emissions during coal mining remains problematic. The International Energy Agency (IEA) estimates that coal mining accounts for about 40 million tons of methane emissions worldwide each year, making it the largest single source of such emissions in the energy sector (although this figure is lower than the share of the oil and gas sectors combined).

Attention should be paid to the use of thermal oxidation technologies to reduce the concentration of ventilation air methane (CMM) that can also play an important role in reducing emissions. Although this is not a new technology: the commercial application of regenerative catalytic oxidation (RCO) and regenerative thermal oxidation of CMM first took place at BHP Billington's West Cliff plant in 2007.

The most effective way to control mine methane emissions is to degasify coal beds with drilled boreholes before methane enters the mine workings. The requirement for degasification of coal beds before they are mined is a requirement of Kazakhstan legislation. Thus, Article 153 "On Subsoil and Subsoil Use" prohibits the development of coal deposits with an increased level of natural methane content of coal beds without taking the necessary measures for early degasification, ventilation programs and formation degasification with subsequent use of the resulting methane, the reduction of methane content in coal beds to the established standards.

7.10 Key findings and recommendations

- Coal will remain paramount to Kazakhstan's economy over the next ten years;
- Export potential, taking into account the growing demand in the EU and Turkey, remains high, which allows to increase the volume of coal production from the Shubarkol deposit;
- The policy of price restraint in the domestic coal market limits the ability of coal mining companies to develop and modernize;
- Taking into account the developed metallurgical complex, the development of low-temperature semi-coke production is promising;
- Transition of coal deposits to the BAT principles will require investments and growth of coal prices, it is necessary to raise public awareness of the necessary price increase.

CHAPTER 8

ELECTRICITY

8. ELECTRICITY

AVANTGARDE ADVISORY AND SEEPX ENERGY

8.1 Key points

- In 2022 - 2023, several major accidents occurred at Kazakhstan's energy facilities. In the city of Ekibastuz, an emergency situation was declared due to an accident in the heat supply system; significant problems were also observed in the operation of the Ridder combined heat and power plant (CHP). A number of other incidents involving power plants and power supply systems resulted in curtailing operations of industrial consumers. Based on the analysis of accidents, the government of Kazakhstan decided to legislate the eventuality of seizing energy facilities from their owners in case of their improper condition or operation.
- In 2023, the Ministry of Energy of the Republic of Kazakhstan completed a large-scale technical audit of all Kazakhstan's power plants (including CHPs), based on which international consultants determined that wear and tear of CHP's main equipment was extremely high. However, the audit methodology and the results obtained raised questions among experts. Based on the data collected during the preparation of this report, the situation with the main equipment does not look as critical as the audit results suggest. More than 47% of turbines have been commissioned after 1991, but the power plants' main problems stem from the high wear and tear of auxiliary equipment and infrastructure,[1] the modernisation of which is not covered by the capacity market mechanism at present.
- Heat energy tariffs, constrained by government regulation, do not cover the full extent of required replacement of the heating networks, impacting negatively the frequency of accidents and level of losses in the heating networks. Most heating networks are on the balance sheets of municipal authorities with a share of repairs (up to 50%) directly covered by the city budgets. As a result, heating networks that are privately owned cannot be modernised properly due to tariff restrictions; namely 14% of heating networks that are privately owned are worn out by more than 77%. Notably, the heating networks in the cities of Ekibastuz and Ridder belonged to private companies, whilst at Petropavlovsk CHP-2, where out of seven turbines three have been installed after 2013, the accident occurred on the auxiliary equipment - the chimney.
- The issues with tariff restrictions also affect the electric power transmission and distribution sector, where the level of wear and tear of the grid assets operated by regional electricity companies (REC) in 2022 exceeded 65%. The production and transportation of the heat energy, as well as the transmission of electricity fall within the natural monopolies regulation, where, despite the introduction of a regulated asset base (RAB) methodology[2] the cost-plus approach governs in practice. Moreover, according to the current tariff-setting rules the allowed profit cannot be paid to the shareholders in the form of dividends, but must be used to fund investment programs. As a result, the network companies operate with virtually zero profits for the owners, who, in some cases, receive income through non-transparent business and procurement schemes. Moreover, due to the deficiencies of the cost-plus tariff methodology used in most cases, the network companies' approved tariffs do not account for the corporate income tax payment, as a result the companies are forced to pay for it from the profits intended for investments. The investment sources depleted in this way compromise the delivery of investment commitments and would result in penalties.
- Despite the government's efforts to modernise both generating and network facilities, the industry is characterized by a significant degree of depreciation of fixed assets, relatively low efficiency (33-35%) of power production, high electricity losses during power transmission (8%), as well as the shortage of flexible capacity to balance the daily schedule and renewable output.
- Forecasts for electricity shortages that arose in the wake of the cryptocurrency mining growth, as well as the relocation of industrial production and companies from Russia in 2022, are most likely premature, given the capacity reserves, including those in the energy-deficient Southern Energy zone, where Zhambul GRES'[3] capacity factor remains quite low (20-34%). The commissioning of Ekibastuz GRES-1 unit 1 515 MW after modernisation in 2024 in Northern Energy zone will offset the anticipated load growth in the energy system. The reliability of power supply in the Western Energy zone could be partially resolved by involving Tengiz field gas turbine power plants' (with the total installed capacity of 488 MW) in the power system's frequency control. The technical re-equipment of MAEK and the construction of highly efficient CCGT units would also help resolve the issues with the power supply in the Western Energy zone
- A fundamental change in the electricity and capacity market model in Kazakhstan has been the 2023 transition to the Single Buyer mechanism, discussed in the previous edition of this report. The Single Buyer purchases electricity from the power plants daily on the basis of competitive selection and sells electricity to the consumers at averaged hourly prices daily. Whereas in a free market the selection of supply is driven by a single factor – the price, the free market mechanisms prevent the selection from becoming more detailed and complex to achieve the energy system effects. In comparison, the Single Buyer mechanism makes it possible to implement the principles of multi-criteria optimization using digital technologies,[4] which in the future can produce significant

1 Boiler houses, cooling towers, fuel oil (mazut) facilities, buildings and structures, etc.

2 Method of incentive tariff setting based on the profitability of the Regulated Asset Base (RAB). Tariffs are formed based on profits and operating costs, while profits directly depend on the value of assets directly involved in the provision of services. This approach stimulates investment.

3 Installed capacity of the power plant is 1,230 MW, available capacity is 1,107 MW.

4 Multicriteria optimisation is a mathematical programming aimed at finding the best (optimal) solution that satisfies several criteria that are irreducible to each other.

systemic effects and surpass the efficiency of free market mechanisms. Simultaneously with the launch of a Single Electricity Buyer Mechanism Kazakhstan launched its balancing market in real time.

- When it comes to the long-term development of the electric power industry 2023 signaled a major political step forward - the decision to hold a referendum on the construction of a nuclear power plant. Nuclear energy could become the foundation for replacing the coal-fired generation, which dominates electricity production in Kazakhstan. In addition, the gasification of the regions and possible additional gas supplies from Russia could affect the replacement of coal-fired boiler houses and CHPs in central and eastern Kazakhstan significantly. The energy transition for Kazakhstan denotes not only the development of renewable energy sources, but also the expansion of gas-fired generating capacity and the construction of nuclear power plants.
- The development of new generation, whether those are nuclear, highly efficient combined cycle gas-fired or new coal-fired power units, will require tariffs sufficient to recoup long-term investments, as well as transparency of the tariff-setting process itself. Acceleration of modernisation and renewal of electric power facilities' fixed assets also require reforms, and this chapter will examine not only the problems in the industry, but also propose changes to the legislation.

8.2 Information about the electric power industry

Kazakhstan's electricity industry is the largest in the Central Asian region. The installed capacity of power plants in Kazakhstan as of 1 January 2023, according to the System Operator (KEGOC JSC), has amounted to 24.5 GW with the thermal power plants (TPPs) as a backbone of generation (over 79% or 19.4 GW), represented by coal (13, 4 GW) and gas (6.0 GW) capacity.

There are 64 thermal power plants in operation in the country, of which: 37 are CHPs, that provide heat energy to the population and industrial consumers, 6 condensing power plants (GRES), 11 gas turbine, 8 gas piston, and 2 combined cycle gas units (CCGTs).

The development of the oil and gas complex in the west of the country has led to a gradual increase in the share of gas generation in the energy balance, whilst the legislative framework adopted since 2014 to support renewable energy sources (RES) has made it possible to increase the share of renewables, which, according to the law, include wind, solar, small hydroelectric and biogas power plants.

Currently, 130 RES with a total capacity of 2,388 MW have been commissioned in the country, of which 46 are wind power plants (WPP), 44 are solar power plants (SPP), 37 are small hydroelectric power plants[5], and 3 are biogas power plants. By the end of 2025, Kazakhstan plans to increase its renewable capacity to 2,900 MW.

Overall, between 2014 and 2022, there has been a 3.6 GW (17%) increase in the installed generating capacity, with renewables accounting for more than 2.4 GW.

The development of intermittent energy sources, such as wind and solar power plants, dependent on weather conditions, requires balancing by flexible power plants, the shortage of which has been noted in Kazakhstan even prior 2014.

In 2022, Kazakhstan held auctions of flexible power plants' projects with a total capacity of 1,716.5 MW: Kyzylorda CCGT 240 MW, Turkestan CCGT 926.5 MW, Almaty CCGT 480 MW, and Zhezkazgan CCGT 70 MW. Commissioning of these power plants is not envisaged earlier than mid-2026, meanwhile the capacity of intermittent sources (wind and solar power plants) will increase by about 487 MW, which will cause an additional challenge for the energy system balancing.

The total capacity of new flexible energy sources after 2026 would be sufficient to overcome the shortage of flexible capacity, but only partially, and it would be necessary to develop hydroelectric generation as the most effective flexible source of power. According to the plans for the development of hydropower until 2030, Kazakhstan plans to build two re-regulating hydroelectric power stations (HPP): Kerbulak HPP (the counter-regulator for Kapchaigask HPP) and the Bulak HPP (the counter-regulator for Shulbinsk HPP), as well as Semipalatinsk HPP.

The shift to renewable auctions as part of the state support of RES development has turned out to be an affective mechanism to put the downward pressure on renewable tariffs and enabled for the commissioning of 1900 MW of renewable capacity. In addition to supporting RES within the framework of the current legislation, a number of new projects support their development. In 2023, an intergovernmental agreement was signed with France for the construction of a wind farm and an energy storage system with a capacity of up to 1000 MW (a joint project with Total), and a principles agreement was signed for the construction of a wind farm and an energy storage system with a capacity of up to 1000 MW (a joint project with Masdar).The RES tariffs are warranted by the intergovernmental agreements, whilst balancing is managed by the energy storage systems (ESS) provided for in the projects.

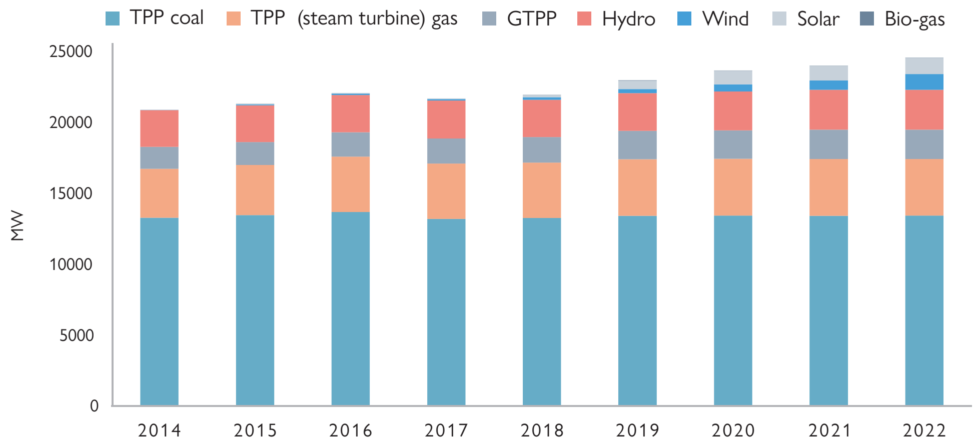
The 2021 amendments to the legislation, effectively equalized waste incineration power plants[6] to RES. In the same year, auctions for the construction of waste-incinerating (waste-to-energy) power plants were held with a plan to commission 100.8 MW. Auctions with one participant were recognized as valid and confirmed the electricity tariff of 172.71 tenge/kWh (without VAT), which was several times higher than RES tariffs. If waste-to-energy power plants had been built, the cost leading to their support would have amounted to 130 billion tenge annually, which would have been comparable to the total cost of renewable energy sources' support in Kazakhstan. However, in April 2023, the government renounced its plans to build waste-incinerating (waste-to-energy) power plants.

On the whole the current support of renewable generation has enabled for the commissioning of 1,100 MW of wind and 1,085 MW of solar generation dependent on weather conditions. Due to the intermittent nature of this generation their output requires balancing by flexible power plants or energy storage. The

5 Hydroelectric power plants with an installed capacity of up to 35 MW, whilst other hydroelectric power plants, according to the law, are not classified as renewable energy sources.

6 In legislation these plants are called "energy waste recycling."

Figure 8.1 Changes to capacity and structure of electricity production by fuel type.



balancing costs associated with renewable output are the hidden costs associated with their support. The use of energy storage systems to balance wind and solar power plants is not the most optimal solution, due to high costs of storage systems and technical limitations to their operation. Ideally, this unstable generation could be balanced by hydro generation if such could be purposely built in Kyrgyzstan and Tajikistan within the framework of regional energy cooperation, but such a solution falls more within politics and the integration processes in the Central Asian region in general.

In terms of regional structure, the energy system of Kazakhstan is divided into three Energy zones - the united Northern and Southern Energy zones, connected by three 500 kV lines, and the Western Energy zone, which operates independently. The Energy zones generation mix is subject to the type of available fuel, and is as follows:

- Only gas-fired thermal power plants operate in the Western Energy zone, the location of the country's key oil and gas fields. Notably, some power plants are the oil and gas fields' own sources of electricity and do not supply electricity to the grid. The region also has the opportunity to meet part of its consumption by importing electricity from the Unified Energy System of Russia (UES Russia). Thus, the Atyrau energy hub has connections with UES Russia's IPS South (Astrakhan energy hub) via a 110 kV overhead line, and West Kazakhstan region has connections with UES Russia's IPS Middle Volga via three 220 kV overhead lines;
- The main coal mining deposits are concentrated in the Northern Energy zone, including the world's largest coal mine Bogatyr. The backbone of the surplus Northern Energy zone is coal-fired generation, including all coal-fired CPPs[7] (traditionally called GRES), as well as hydroelectric power stations in eastern Kazakhstan. About 70% of the country's total generating capacity is concentrated in the Northern Energy zone. The developed electricity network of 220-500-1150 kV lines, including one connecting the Unified Energy System of Kazakhstan and the IPS Siberia of UES Russia, makes it possible to transmit electricity both to the Southern Energy zone and to exchange flows with UES Russia. The Northern Energy zone is a home to the main industrial consumers of electricity, including the mining and metallurgical industries;
- The Southern Energy zone is energy deficient. In terms of electricity consumption, this is the area with the largest share of population, whilst the generation mix is diverse, and consists of both coal-fired and gas-fired generation, as well as some hydropower. Notably, this zone is a country leader in the development of small hydropower generation. The Southern Energy zone's power deficit (11.5 billion kWh) is met by the flows from the Northern Energy zone. Due to climatic conditions, it is most suitable for the development of solar and wind generation. However, the lack of flexible capacity reserves and related existing regulation and balancing issues prevent Kazakhstan from tapping into this environmental capital. The largest gas-fired power plant Zhambyl GRES, is located in the Southern Energy zone as well. Since 1992 it has been operating inefficiently at a reduced load due to issues with the supply of natural gas (initially from Uzbekistan). At the same time, the commissioning of Beineu-Bozoy-Shymkent gas pipeline in 2015 did not solve the issue of low capacity utilization. The consequence of price competition from the coal-fired CPPs in the Northern Energy zone is significant underutilization[8] of gas-fired generation even in the energy-deficient Southern Energy zone. Naturally, investment into modernisation will be required to launch all units at Zhambyl GRES, but the downtime of such a powerful source in an energy-deficient area greatly reduces the reliability of power supply.

Notably, the Energy zones' imbalance is primarily caused by the distribution of generating capacity. In the Northern Energy zone the installed capacity of the power plants is 16.4 GW, whilst in the Southern Energy zone it is only 4.5 GW. The deficit of the Southern Energy zone is met via three 500 kV North-South transmission lines, but this route is characterised by a regular overload of the power lines.

Currently, there is a plan for the complete unification of all three Energy zones by the means of constructing a 500 kV Atyrau-Aktobe overhead line with a length of about 500 km.

7 Condensing power plant (CPP) - a thermal power plant that produces electricity only.

8 The deficit of the Southern Energy Zone is about12 billion kWh, loading the Zhambyl State District Power Plant to 80% capacity can reduce the deficit by 6 billion kWh.

Kazakhstan ranks ninth in the world in terms of territory, so the electricity transmission over long electricity networks is characterized by relatively high losses. The power grid infrastructure of the national operator of the main electric networks KEGOC consists of the networks with a voltage of 500 - 220 kV with a total length of more than 26 thousand km and networks of regional power grid companies with a voltage of 220 - 10/6 kV with a total length of more than 250 thousand km. This long-distance of the power grid contributes to high (>8%) losses of electricity during transmission.

The electric power industry in Kazakhstan also includes the production and transportation of heat energy. The sources of heat energy supply are 37 CHPs, 63 large and 2,200 small boiler houses, with thermal power plants meeting about 60% of centralised heat energy supply. The heat energy is transported via heating networks (main and district) with a total length of more than 12 thousand km. The industry is characterised by high losses during the transportation of the heat energy, which can reach 30% (17% as per the official statistics), low efficiency of heat energy sources and a high degree of wear and tear of the main equipment. On average, country-wide wear and tear of the heating networks is more than 60%, while the wear and tear of privately owned heating networks is more than 77%, which are caused by significant tariff restrictions.

8.2.1 *Power generation*

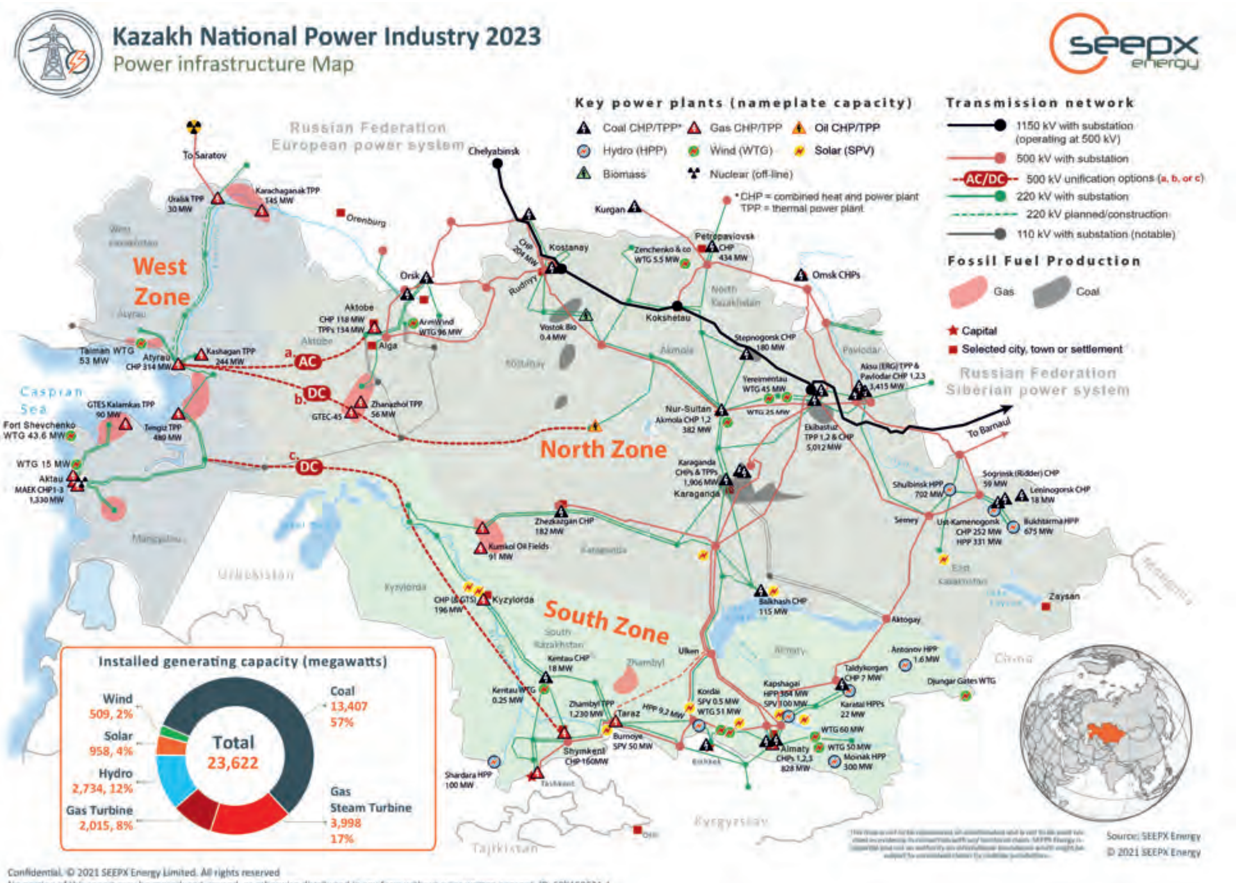
According to the System Operator (KEGOC JSC), electricity production in Kazakhstan in 2022 amounted to 112.9 billion kWh, which is 1.3% less than in 2021. Notably, the Northern Energy zone accounts for the decrease in power production (3.9 billion kWh).

The structure of electricity production in Kazakhstan is dominated by coal-fired generation, which accounts for 68.2% of the total electricity production in the country. Gas-fired power plants produce 20.1% of electricity, hydroelectric power plants produce 8.1%, and wind and solar power plants account for 2.1% and 1.6% of electricity production, respectively, see Figure 8.3.

Since 2014, total electricity production has increased by 20% (18.9 billion kWh), while the share of coal-fired generation has decreased from 72.9% to 68.2% due to the development of renewable energy sources and gas-fired generation. Notably, in 1990 the share of coal-fired generation was more than 80%. At the same time, the industry accounts for more than 60% of electricity consumption in Kazakhstan.

The operation of thermal power plants includes consumption of electricity for the plants' own needs; whilst for coal-fired thermal power plants electricity consumption for own needs is estimated

Figure 8.2 Kazakhstan's energy infrastructure map.



at 5-6%, for CHPs, that also supply heat energy, the electricity consumption for own needs is about 11-17%. Updating equipment and optimising operation help reduce electricity consumption for plants' own needs.

As part of their investment commitments Kazakhstan's thermal power plants constantly update fixed assets, but mainly turbine equipment, see Figure 8.4. Thus, the total thermal power plants' turbine capacity installed after 1991 is 9.1 GW or 47% of the thermal power plants' total installed capacity .

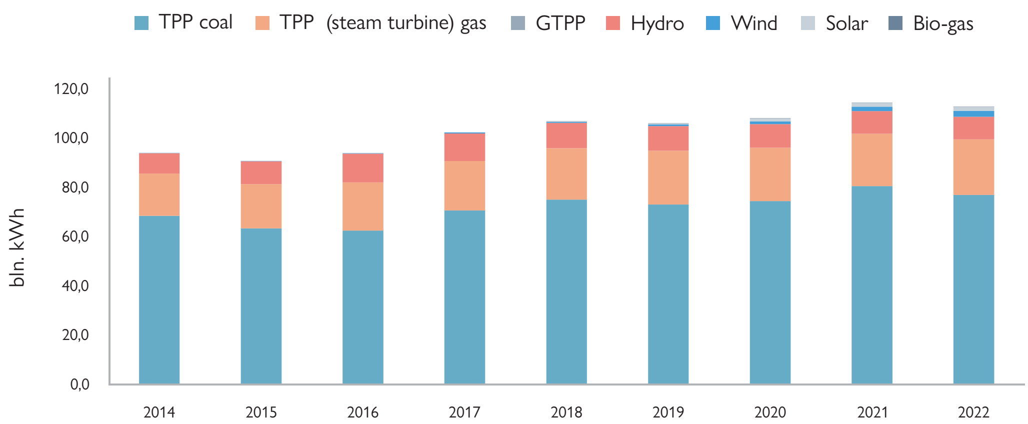
The volume of investment into modernisation through the capacity market mechanism is still significantly less compared to the annual investment into industry during 2009–2015.

The renewal of CHP's fixed assets is not carried out to the full extent, especially when it comes to the auxiliary equipment. A high share of the thermal power plants' wear and tear is attributed to the auxiliary equipment. The capacity tariff does not cover modernisation of auxiliary equipment, it is prohibited to include auxiliary equipment into modernisation programs covered by the capacity payment. The accident with the collapse of a chimney at Petrovavlovsk CHP-2 in 2022 occurred precisely because of the lack of major repairs of the pipe belts. Notably, there is no uniform methodology for calculating the capacity tariff for the power plants' modernisation programs, and tariffs are calculated differently subject to projects, which does not warrant the return on investment.

45%. As a result, the technical re-equipment of coal-fired power plants with the power units with the ultra-supercritical steam parameters, the per unit fuel costs will reduce by 15-20%. The efficiency of coal-fired power plants' units in Kazakhstan does not exceed 35%, while some power units operate with a lower efficiency due to resource depletion. The planned construction of coal-fired units at Ekibastuz GRES-2 and Ekibastuz GRES-3 in Kazakhstan must be accompanied by the planned decommissioning of obsolete and depleted units at Ekibastuz GRES-1. An assessment of replacing one 500 MW coal-fired unit with a new unit with the efficiency of 42% with the comparable power generation (at 80% capacity factor) will lead to a reduction in greenhouse gas emissions by approximately 560 thousand tons of CO_2.

Another important issue for the energy sector in Kazakhstan is the future of the large power plant in the Western energy zone - MAEK (Mangistau Nuclear Energy Plant). Since its launch in 1968, MAEK's objective has been to supply regional industry and population with electricity, heat energy, and desalinated water. Until 1999, MAEK operated the BN-350 nuclear reactor, used to produce electricity and desalinate salt water. After the nuclear reactor has been shut down gas has been used for desalination purposes. MAEK's installed capacity is 1,330 MW, the wear and tear of MAEK's turbine equipment exceeds 86%, and by 2025 the plan is to decommission 205 MW (CHP-1 - 25 MW and CHP-2 - 180 MW). MAEK's electricity production is characterized by an extremely intensive use of gas for the production of power and low capacity factor (for comparison, the CCGT units' gas consumption is approximately twice as lower).

Figure 8.3 Structure of electricity production 2014– 2022

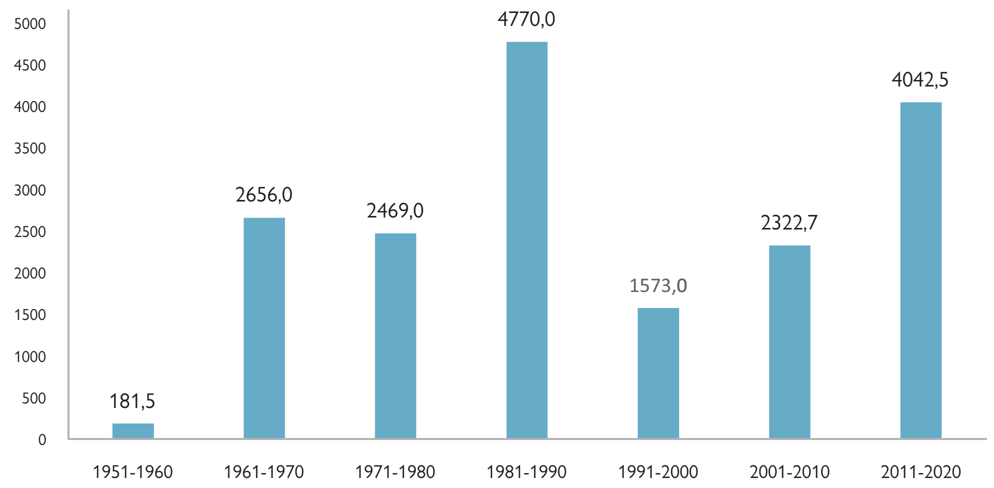


In accordance with the requirements of an environmental legislation, apart from modernisation, coal-fired power plants are required to shift to the best available technologies (BAT) with the introduction of relevant systems for reducing emissions of dust, nitrogen oxides and sulfur, and, starting from the next year, to establish a financial fund to eliminate the consequences of their operation after decommissioning.

Another direction for the evolution of coal-fired generation is the integration of highly efficient generation with the efficiency exceeding 41%. The power units with the ultra-supercritical steam parameters (USCP), pressure above 30 Mpa, and temperatures of 600 °C and higher have been actively introduced over the past 10 years in a number of countries around the world, but primarily in China. The efficiency of such power units reaches

Given the planned retirement of MAEK's capacity in 2026–2027 it would be worth considering a project for the construction of combined cycle gas units with the capacity of 250 MW. Following this, we recommend to replace MAEK's retired capacity gradually with the combined cycle gas units. MAEK's site has sufficient space for the construction, the availability of electricity and gas infrastructure, and the grid connection is designed for the output of 1,300 MW. Given extremely intensive levels of gas consumption for the power production at MAEK the shift to the highly efficient CCGTs will facilitate reduction in gas use when compared to the current levels.

Figure 8.4 Turbine launches, MW



8.2.2 *Electricity transmission and distribution*

The national electricity grid (NEG) infrastructure with a voltage of 500 - 220 kV is a backbone for the electricity connections between the country's regions and the energy systems of the neighboring countries. KEGOC is the operator of the NEG. Domestically, in the regions the electricity is distributed via the networks of 196 energy distribution companies (abbreviated in Russian as EPO), including 19 regional electricity grid companies (REC), and 301 energy supply companies (abbreviated in Russian as ESO) that supply electricity to the retail consumers.

EPOs could be companies that use their own industrial networks to supply energy to consumers, for example, KazTransOil JSC and NC Kazakhstan Temir Zholy JSC (KTZh). The national electricity grid ensures the electricity transmission from the power producers (who have a grid connection for the power output to NEG) to the wholesale consumers (electricity distribution companies, large consumers) connected to this grid. KEGOC provides services for the use of the NEG.

The total volume of electricity transmission in 2022 through KEGOC networks amounted to 58.6 billion kWh, while REC networks distributed 43.3 billion kWh; the total volume of electricity losses amounted to about 7.5 billion kWh, see. Table 8.1.

When it comes to RECs' electricity grid infrastructure the main issues are high losses of electricity and depreciation of fixed assets. In 2022 electricity losses during transmission via KEGOC networks amounted to 2807.7 million kWh (4.9%), while losses in RECs' networks were 4739.5 (10.9%), see Figure 8.5. At the same time, the degree of wear and tear of electrical grid equipment in RECs' networks remains high (on average above 65%) despite the fact that, according to companies, annual investments amount to about 30% of income.

RECs' tariff policy is a limiting factor when it comes to investments; the shift to the incentive tariff regulation specified in Kazakhstan's legislation has not taken place by the majority of RECs and the cost-based methodology is still widely used. The transition to the incentive tariff in the current version of the legislation is not beneficial for REC's owners, since the calculation of tariffs becomes more complicated, additional obligations are introduced to achieve target indicators, and all profits must be directed towards investments in full.

The international experience has demonstrated that besides increased efficiencies and quality of operations the transition to incentive tariff regulation has created conditions for the companies to reduce their impact on the environment, owing to the incentives for the integration of distributed energy sources (including RES) and demand response. At the same time, given high depreciation of the power grid assets, the network companies simultaneously have been able to address the issues with updating the fixed assets and attracting investment into new assets and technologies, whilst maintaining the end consumer tariffs within the range established by regulators. As part of the incentive tariff, in addition to modernization goals, additional targets relating to environmental impact and energy efficiency can also be set in Kazakhstan. However when it comes to setting tariffs within the incentive methodology framework it is important to guarantee a minimum rate of return for the network companies, which will help encourage regional energy companies to switch to incentive tariffs and accelerate the modernisation of the power grid infrastructure.

Digitalisation of the power networks and infrastructure is a promising pathway for reducing losses, optimising operational modes and improving the reliability of energy supply. According to KEGOC the company has already embarked on “Automating the Unified Energy System of Kazakhstan Management”, that focuses on three areas: the automated frequency and capacity control (abbreviated in Russian as ARChM); the centralised automatic emergency response system (abbreviated in Russian as CSPA); the synchrophasor WAMS/WACS technologists.

Within the scope of Western Energy zone unification with UES Kazakhstan KEGOC has embarked on a feasibility study for the construction of a 500 kV North-West AC line, most likely Atyrau-Aktobe route, with a length of 500 km. The project 's completion is estimated by 2030.

9 https://ec.europa.eu/commission/presscorner/detail/en/MEMO_11_125.

Table 8.1 Length of KEGOC's and some of RECs network infrastructure.

	length, km	
Voltage	**KEGOC**	**REC**
1150 (in 500 kV mode)	1421.2	0.0
500 kV	8288	0.0
330 kV	1864.1	0.0
220 kV	14890	1428.2
110 kV	352.8	22857.2
35 kV	44.1	27082.2
10 kV	110.2	51315.9
6-0.4 kV	13.1	47613.1

Overall, the construction of new power transmission lines, the goals of reducing the wear and tear of the power grid infrastructure, and the challenge of digitalisation (for losses reduction amongst other things) will require increased levels of investment and a tighter control over the efficiency of spending. In this regard, the industry reform with the subsequent transition to the incentive methods of tariff setting (warranting profitability and return on investment for the companies in this sector) must be accompanied by an ***increased independent control over the efficiency and effectiveness of spending.***

8.2.3 Electricity consumption

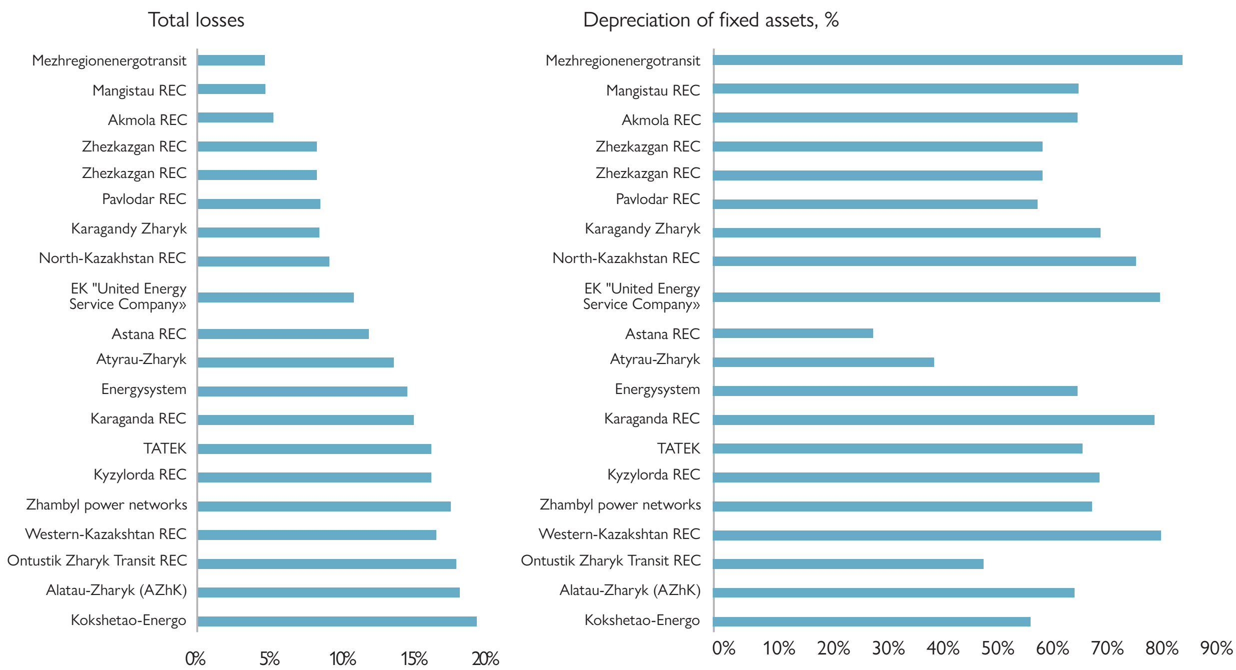
The power consumption in Kazakhstan exceeded 1990 levels only in 2018, see picture 8.6. Notably, during the soviet era, a substantial share of power supply originated from Russia and Central Asian countries, whereas at present Kazakhstan meets almost all of its power needs with its own generation.

According to the System Operator, Kazakhstan's electricity consumption in 2022 amounted to 112.9 billion kWh, which is 0.8% lower than in 2021.

Between 2014 - 2022 the largest increase in electricity consumption was registered in the Northern Energy zone and amounted to 9.53 billion kWh, whilst in the South Energy zone the increase was 3.43 billion kWh, and in the Western Energy zone it was 2.59 billion kWh, see Table 8.2.

Notably, industry accounts for the largest share (57.9%) in the structure of electricity consumption with housing and communal services (abbreviated in Russian as ZhKH from zhilicshno-kommunalnoye hozyaistvo) accounting for 22.3%, see Figure 8.8. Aksu Ferroalloy Plant is one of the largest producers and suppliers of ferroalloys in the world and is the largest consumer of electricity in Kazakhstan accounting for about 4.6% of the country's total electricity consumption.

Figure 8.5 Losses in REC networks (left) and depreciation of fixed assets (right), 2022



The power consumption by large industrial consumers accounted for more than 33.6 billion kWh in 2022; compared to 2021 electricity consumption increased for the following large consumers: Kazakhmys Smelting LLP, Tengizchevroil LLP, Kazakhmys Corporation LLP , UKTMK JSC (Ust-Kamenogorsk Titanium-Magnesium Plant), NK Kazakhstan Temir Zholy JSC, Pavlodar Aluminum Plant JSC, AZF TNK Kazchrome JSC.

The growth in electricity consumption in Southern Kazakhstan (Almaty and Turkestan regions) is mostly associated with the growth of region's population; particularly in Almaty and the Almaty region.

At the moment, the power consumption in Kazakhstan largely depends on the pace of industrial growth and the situation at the global commodity markets, since the main exported products are raw materials and semi-finished products, namely oil and petroleum products, natural gas, metal ores, and alloys.

At the same time, Kazakhstan's electricity consumption could find support from the emergence of new industries and consumption formats. For example, in 2021, Kazakhstan ranked third in the world after China and the United States in cryptocurrency mining with a total share of 8.2%,[10] which continued growing thereafter. In 2023, according to the Kazakhstan Blockchain Technology Association, the country's share in global mining fell from 18.3% to 6%, as a result of increased control and disconnections of illegally connected mining farms. Notably, the cryptocurrency mining in most countries is a shadowy area and it is very difficult to determine the volume of electricity consumption by this industry. Kazakhstan's policy on digital financial assets and currencies has been defined in a new law “On Digital Assets”.[11] From 1 January 2022 the government of Kazakhstan has introduced a special tax on cryptocurrency mining.[12] Moreover, separate tenders for the power supply to the miners are held by the Single Electricity Buyer. Sanctions against Russia resulting from the military conflict in Ukraine have resulted in the decision of a number of Russian companies to relocate their production sites to Kazakhstan. This important factor should be accounted for when forecasting the power demand.

An uneven distribution of generating capacity by Energy zones, the issues with the North-South transit congestion, and the unevenness of consumption growth by energy systems bring to the forefront the importance of efficient energy system planning. The challenges associated with demand forecasting also include changes to the duration and nature of peak power consumption as a result of temperature and anomalies variations, duration and frequency caused by climate change.

8.2.4 Industry regulation

Based on the recommendations from *The National Energy Report 2021* Kazakhstan has introduced the Single Electricity Buyer model, which was a significant change in the design of its electricity market. Other recommendations for electricity regulation have not been implemented yet. The effectiveness of the mechanisms for regulating the industry by the state is critically important for the development of the electric power industry. With this regard the key proposals of how to reform the power sector are listed in section 9.3 of this report. . The key government bodies responsible for regulation and price-setting policy in Kazakhstan's electricity industry are:

The Government of the Republic of Kazakhstan

The operation of the electric power industry in Kazakhstan is governed by the norms of the Law of the Republic of Kazakhstan “On the Electric Power Industry”, the Law “On Natural Monopolies”, and the Law “On Support of Renewable Energy Sources”. The laws define the principles of the electric power sector and the renewables sector operation, approaches to

10 Based on an estimate by the University of Cambridge, electricity consumption for cryptocurrency mining in the world is about 130 billion kWh, therefore, the industry's consumption in Kazakhstan could be up to 10 billion kWh, however, this estimate seems overestimated, and the consumption for mining is much less.

11 Law of the Republic of Kazakhstan dated February 6, 2023 No. 193-VII ZRK.

12 The tax is calculated on electricity consumption per 1 kWh of electrical energy consumed during digital mining, depending on the cost of electricity.

Figure 8.6 Electricity consumption and peak load in 1990-2022

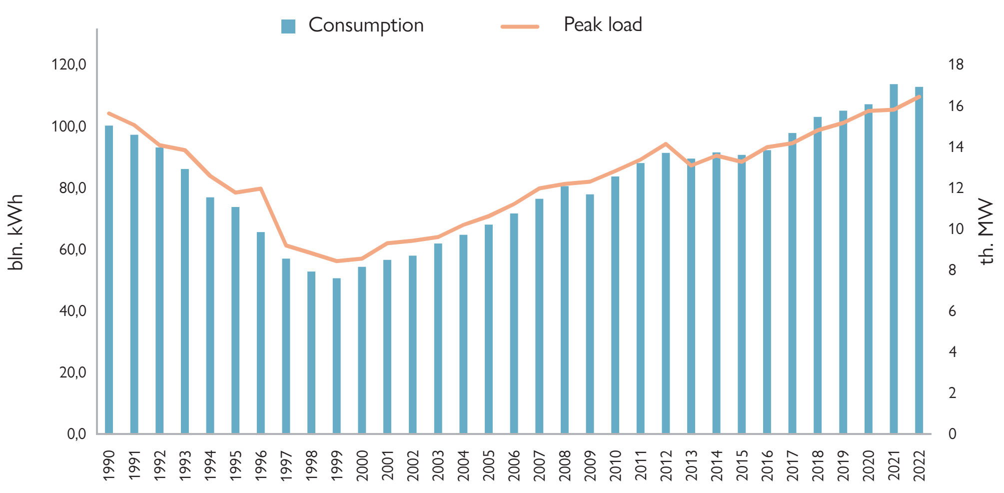
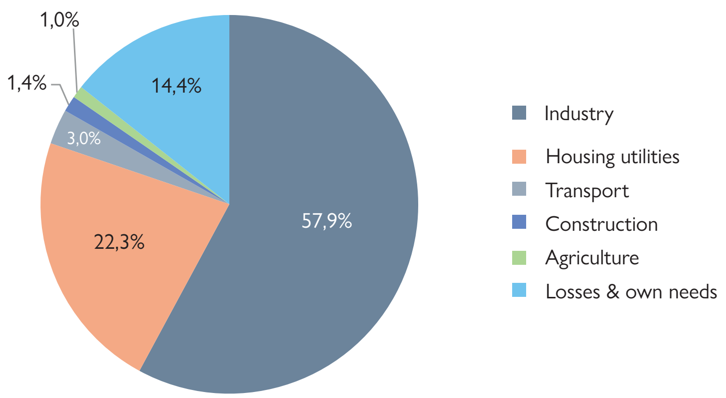


Table 8.2 Growth in electricity consumption by region in 2014–2022

	Regions	2014	2015	2016	2017	2018	2019	2020	2021	2022	Change 2022/2014
Northern	East Kazakhstan/Abai	8664	8523	8530	8563	9080	9339	9204	9640	10310	**+11.9%**
	Karaganda/Ulytauskaya	15433	15712	15786	16695	17319	17991	18460	19000	19080	**+23.6%**
	Kostanayskaya	5473	4688	4599	4689	4782	4786	4615	4810	4590	**-16.1%**
	Pavlodarskaya	17363	16975	17611	18654	19433	19527	20731	21480	19400	**+11.7%**
	Akmola	7996	8061	8285	8645	9141	9209	9196	10310	10690	**+33.7%**
	North Kazakhstan	1704	1643	1685	1731	1800	1764	1665	1730	1610	**-5.5%**
	Aktobe	4232	4798	5272	5900	6301	6437	6647	6890	6940	**+63.9%**
South	Almaty/Zhetysu	10168	9917	9960	10446	10977	11351	11367	12450	12850	**+26.4%**
	Turkestan	4148	4090	4270	4646	4953	5097	5211	5760	6010	**+44.8%**
	Zhambylskaya	3898	3782	3191	3802	4321	4473	4948	5320	4980	**+27.8%**
	Kyzylordinskaya	1642	1605	1592	1658	1689	1760	1760	1950	1940	**+18.1%**
Western	Mangystau	4898	4978	5011	4956	5237	5111	5023	5270	5300	**+8.2%**
	Atyrauskaya	4251	4272	4711	5537	6185	6350	6255	6670	6690	**+57%**
	West Kazakhstan	1791	1804	1808	1931	2009	1998	2256	2610	2550	**+42%**

Figure 8.7 Structure of electricity consumption by industry (2018 estimate).



setting prices for energy producing companies (conventional and renewable), energy transmission and power supply companies, design of the electric power and heat energy markets, and establish the functions of market entities in the sector.

In accordance with the Law "On the Electricity Industry", the government of the Republic of Kazakhstan develops the main direction for state policy in the electric power industry.

The Ministry of Energy

According to the legislation, the Ministry of Energy (with more than 80 scopes of duties) is charged with the implementation of state policy in the electric power industry as set out in the Law "On the Electric Power Industry".

When it comes to price and tariff regulation in the electric power industry, the Ministry of Energy is responsible for setting the power price caps for electric power, the price caps for balancing, and the price caps for capacity. In addition, the Ministry of Energy sets individual capacity tariffs for existing and newly commissioned power plants.

The Committee for the Regulation of Natural Monopolies (CREM) of the Ministry of National Economy

The Committee performs the state regulation and control of natural monopolies.

The Committee sets tariffs for the services of natural monopolies:

- transmission and/or distribution of electricity;
- production, transmission, distribution and/or supply of heat energy;
- technical dispatching to the network and consumption of electrical energy;
- power production and consumption balancing.

Renewables policy support in Kazakhstan

Wind and solar power plants, which form the basis of renewable energy capacity, require government support due to their relatively high cost of electricity and the unstable nature of generation. Industrial and other consumers require a reliable source of energy supply rather than weather-dependent intermittent generation. Therefore, both in Kazakhstan and throughout the world, renewable energy sources are being integrated into the energy system upon receiving various types of support. The hidden costs associated with renewable energy sources are the costs of their integration into energy systems.

Since 2014, Kazakhstan has been constantly improving legislation supporting renewable energy sources. As a result, the following RES support mechanisms are currently in effect:

- a single buyer of renewable energy (RFC for RES) purchases the entire volume of renewable output;
- the purchase of the entire volume of renewable output at auction prices is warranted for 20 years under an agreement with RFC RES;
- RES tariffs are indexed annually, and adjusted to the currency exchange rate in the event of devaluation of the national currency;
- for the auction winners, starting from 2022, tariffs are indexed during the construction of renewable energy sources from the moment the agreement with RFC RES is signed;
- RES producers are exempt from paying for transmission services;
- there is priority RES connection to the electricity networks;
- RES get land reservations during auctions, subject to grid infrastructure;
- RES developers enjoy tax preferences provided for them by the law

This level of government support creates high level of stability for investors, which in turn made it possible to introduce renewable energy capacity in such a short period of time.

However, the calculation of the auction price might be insufficient to attract investors to auctions. In addition, more information is required about Kazakhstan's hydro potential and reservation of sites large hydropower plants. For new hydropower projects, the issue of reserving and allocating land plots is the most problematic.

8.2.5 Electricity market and Single Electricity Buyer

The Republic of Kazakhstan was the first of the post-Soviet countries to launch a free competitive electric power market in 2004 with the adoption of the Law "On the Electric Power Industry".

The wholesale electricity and capacity market includes:

- decentralized market (market of bilateral agreements);
- centralized market (day ahead and intra-day trading);
- system services and auxiliary services market;
- balancing market (until 1 July 2023 it operated in a simulation mode);
- capacity market, launched on 1 January 1 2019 to facilitate return on investments into modernisation and re-building of existing power plants and construction of new conventional generation.

The wholesale power market liberalisation as it had been envisaged in the Law "On the Electric Power Industry" has not been fully completed, and the market has operated on the basis of bilateral agreements between wholesale consumers and generating companies trading power at free prices (later at capped power tariffs).

The Government of Kazakhstan has created a regulatory, technical, and organisational structure for the operation of a centralized power market, including the spot market for day ahead and intra-day trading. However, despite the noticeable progress during the initial stage of the power sector reform any further progress stalled.

When it comes to the structure of the power market, the number and affiliation of its participants Kazakhstan's market represents an oligopoly.[13] Under such a model, the limited number of producers prevents the market mechanisms from being effective and sufficient for the competitive regulation of electricity prices, whilst the limited number of buyers at the electricity market, some of whom are affiliated with the power producers (RECs, ESOs), do not put sufficient competitive downward pressure on the electricity price.

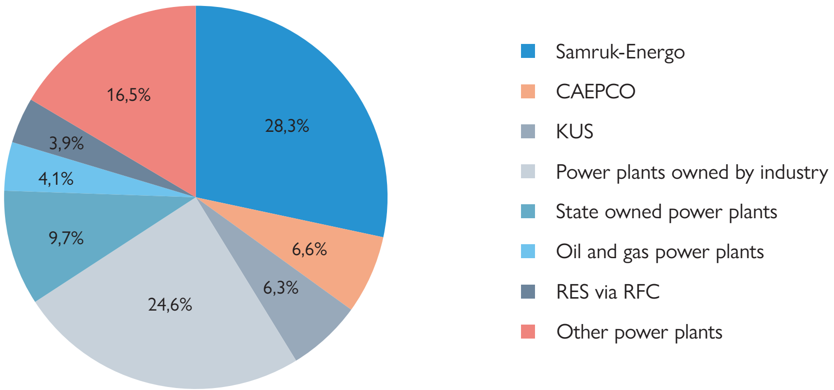
On the other hand, the power plants have different net costs and cost structures limiting the effectiveness of market mechanisms..

Since 2009, Kazakhstan has been unable to find the necessary balance between market liberalisation and the resources intended for modernization and expansion and required for the energy companies (generation and electric networks). In addition, the excess generating capacity that used to be in the energy system in the past obscured the urgency and need for a serious long-term power industry development forecasting.

The significant surplus generating capacity that the country inherited after gaining its independence and the during the decline in economic activity has been exhausted as the country's economy grew. The energy system has already faced electricity shortages in 2007-2012. The "Tariff – for- investment" scheme that introduced marginal tariffs for electrical energy has become the answer to the issues then. As a result, the emerging deficit has been eliminated and a medium-term power reserve has been created by launching 1.2 GW of new capacities and restoring 1.7 GW of existing ones.

At present, Kazakhstan faces a challenge of attracting investments into large infrastructural projects that envisage the expansion and modernisation of generating assets and the power grid. To attract significant investments into the power industry it would be necessary to develop a long-term tariff policy that would enable to balance the interests of the state, consumers, and energy companies.

Figure 8.8 Structure of electricity production by plant owners.



The first significant step in establishing a new market structure that would enable to resolve these complex issues has been the transition from a competitive power market model to the model of a Single Electricity Buyer from 1 July 2023. This shift has been preconditioned by the following:

- a highly concentrated electricity market structure (60% of electricity is supplied by five energy companies);
- the inability for a genuine competition between the power plants due to difference in technology and respective difference in production costs, for example, CHPs (combined heat and power plant), GRESes (condensing power plant) or HPPs (hydroelectric power plant);
- State price regulation and the introduction of power price caps has led to the allocation of power plants to either "cheap" or "expensive" groups. At that, all consumers could not get access to "cheap" power due to limited supply and the sale of power at cheap prices under free bilateral agreements on terms dictated to by the energy producing companies. Notably, almost the entire wholesale market volume (more than 99% since 2020) has been sold under bilateral agreements;
- non-transparency of power sales and supply;
- Illiquid centralized electricity market; lack of power price volatility due to state price regulation and capped tariffs for generation.

Financial Settlement Centre for the support of renewable sources of energy (RFC for RES), an organization subordinate to the Ministry of Energy, has been appointed a Single Electricity Buyer.

When purchasing electricity, the Single Electricity Buyer:

- purchases planned RES output in full (those that have signed an agreement with RFC for RES);
- purchases planned capacity from the power plants that have entered into long-term capacity contracts with the Single Electricity Buyer in full;
- purchases planned electricity output from the energy producing companies that comprise of CHPs, in full;
- purchases the remainder of the electric power from the energy producing companies regardless of their type (GRES, HPP, etc.) based on the results of a centralised trade on a competitive basis;
- if necessary, imports electricity and capacity.

The Single Electricity Buyer sells:

- electricity at fixed prices to the consumers with the targeted support;
- electricity at renewable tariffs to the industrial groups ("conditional" consumers);
- electricity to the digital mining companies following the rules of upward price bidding;
- electricity at settlement daily price to all other market consumers.

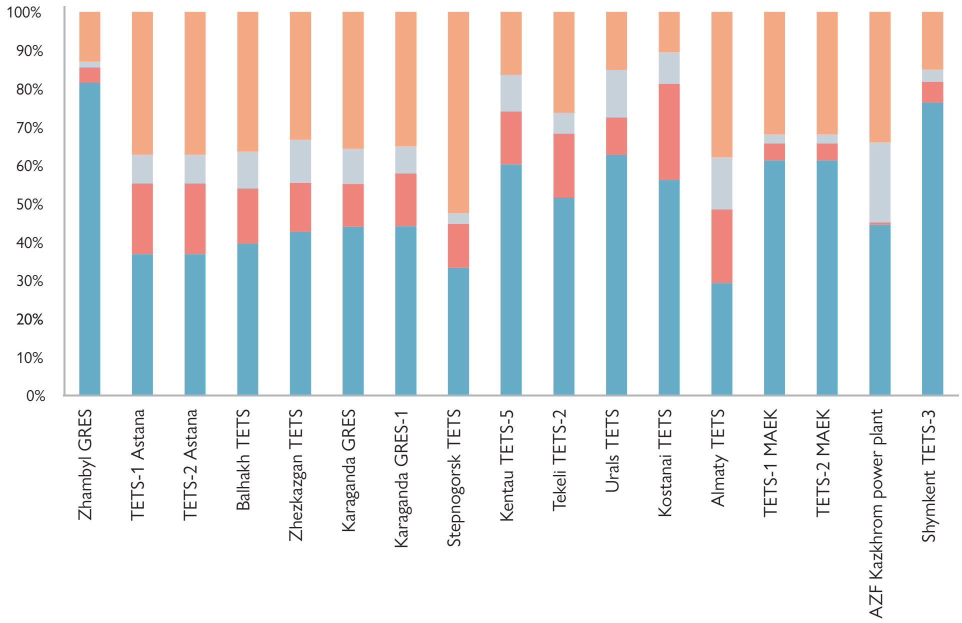
It is premature to draw conclusions about the success of a new Single Buyer model, due to the very short time of its operation at a time of publication. However, the mechanism of a Single Electricity Buyer may turn out to be more effective when compared with the earlier model in the context of anticipated growth of generating capacity, need for a competitive selection of electricity suppliers, the requirement to guarantee returns on investment for the new power projects, as well as the possibility of using internal reserves for balancing.

The risks and issues of a Single Buyer model are:

1) The immaturity of regulatory framework at launch of a Single Electricity Buyer model creates difficulties for the wholesale electricity and capacity market participants. In particular, the standard agreement between the Single Buyer and conditional consumers (industrial groups) has not been approved yet;
2) The legal acts have not clearly defined or attributed the areas of responsibility to the following infrastructural organisations: RFC for RES, KOREM, KEGOC, which also creates difficulties for the market entities when it comes to disputes;
3) The decision to introduce a single power tariff for all consumers has been postponed indefinitely, including consumers with targeted support that purchase electricity at prices lower than the Single Buyer's settlement price. On the one hand, this would help prevent a sharp increase in electricity tariffs, including those for the residential

13 Oligopoly refers to a type of imperfectly competitive market structure in which an extremely small number of product suppliers/sellers predominate.

Figure 8.9 The thermal power plants' costs structure.



consumers; on the other hand, this could result in price subsidies of some consumers at the expense of the others, which would subsequently lead to consumer discontent;

4) The most significant risks of a Single Buyer model are associated with potentially poor payment discipline and possible cash gaps. This is due to the fact that some of the wholesale electricity market participants, namely ESO GP (suppliers of last resort), do not make advance payments for electricity (the share of such consumers in the market is about 30%). For the energy producing organisations (power plants), this means that they will receive full payments for the produced electricity (provided that all consumers meet their financial obligations) within 45 days after the cut-off date of the current billing period (a calendar month). Therefore, it is unclear how the energy producing organisations are expected to fund their business activity during these periods, including purchasing fuel in advance and making the required repairs, etc.

Moreover, the legislation on the electric power industry does not envisage a working mechanism to support the Single Buyer if it defaults on its commitments towards energy-producing organisations. Since the sustainable performance of an entire electric power industry depends on the financial health of a Single Buyer and its ability to make timely payments to the wholesale market participants, it is important to consider setting a fund supporting the Single Buyer. With this regard, one can study the experience of setting and operating a reserve Single Buyer fund insuring against non-payment to the renewable producers.

The operation of a Single Buyer model in the context of administrative price regulation for generation should be largely aimed at addressing the energy system task of achieving an optimal load and committing the most cost-effective units. It would be possible introduce multi-criteria optimisation methods of unit commitment based on many input parameters, such as greenhouse gas emissions reduction, minimisation of fuel consumption for the production of 1 kWh of electricity, minimisation of the final cost of electricity for the energy system as a whole, etc., rather than a single price-based unit commitment.

As a result, the transition to the mechanism of a Single Electricity Buyer could make it possible to create a fundamentally new alternative to the free market and a more efficient energy system built on mathematical principles and information technology in the future. Alongside the Single Electricity Buyer Kazakhstan launched its balancing market in real time in July 2023. However, there is not enough data to analyze its effectiveness due to limited time since its launch.

8.2.6 Approaches to return on investment in modernizing power plants

Since 2009, Kazakhstan applied price caps to the price of electric power. The introduction of price caps for power generating companies has been an attempt to resolve the challenge of generating capacity inadequacy by modernising the country's generating assets in the shortest possible time. In exchange for receiving a higher price cap each power plant committed to a 2009–15 investment plan. Maximum tariffs were subject to annual adjustment, taking into account the need to ensure the investment attractiveness of the industry. The price caps were subject to annual upward adjustments so to maintain the investment attractiveness for the industry. In 2009–15, under this "tariff-for-investment" price-cap scheme, the power sector attracted about USD 6.8 billion into expansion, modernisation, and overhaul of existing power plants. The "tariff-for-investment" scheme was successfully completed at the end of 2015 adding about 3,000 MW of generating capacity to the energy system .

The "tariff-for-investment" price-cap scheme was replaced by capacity market that was launched in Kazakhstan in 2019. Following the launch of the capacity market and subsequent changes to the wholesale market legislation, the consumers' power price changed to accommodate the two variables: the price cap for the electric power set by groups of energy producing companies (the tariff for electric power) and the price for the services of maintaining the capacity “ready to generate” (the capacity tariff).

The capacity tariff for the wholesale consumers is made up of the following averaged costs:

- The cost of the newly commissioned capacity
- The cost of modernised capacity or of the capacity undergo-ing expansion
- The cost of CHPs capacity in the volume necessary to meet the heat load schedule
- The cost of capacity selected during the centralised annual trade
- The Single Buyer's costs

The sum of the total costs, accounting for the Single Buyer's commission (RFC RES from raschetno-financoviy tsenter podderzhki vozobnovlyayemykh istochnikov energii), are divided by the total amount of absolute peak consumption load for the coming year (calculated from the total amount of consumption during the peak hour). A single capacity price that derives from these calculations is set in tenge/MW/month. Notably, there is lack of transparency and market mechanisms for selecting and determining the capacity tariff for modernised and expanded power plants.

The terms of such projects, as well as the price for power, are established individually by the Ministry of Energy based on the recommendations of the Council of the Kazakhstan Electric Power Association, appointed by the decree of the Ministry of Energy as the Market Council. The Market Council includes representatives of energy companies only, thus the Market Council executive committee cannot be fully objective when making decisions, including those on the power plants' investment projects, that in the end of the day would be paid by the end consumers.

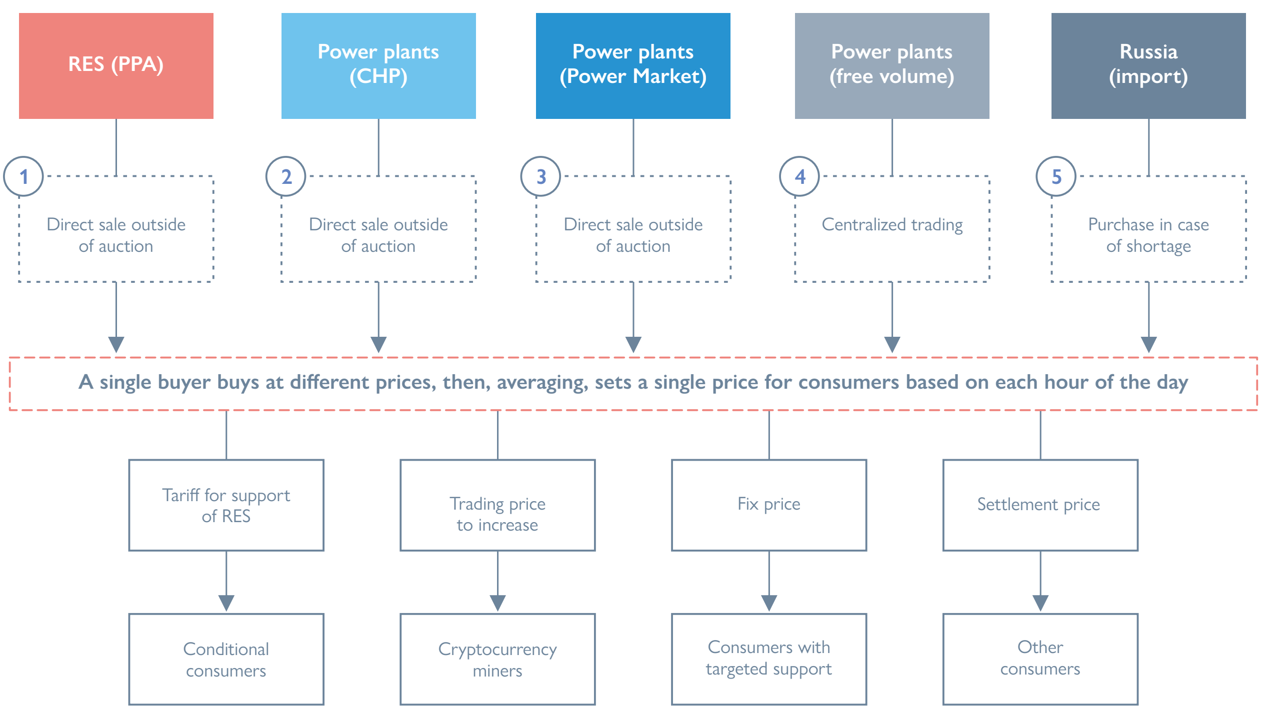
The capacity tariff for power plants undergoing modernisation excludes the costs of modernising the auxiliary equipment, which ultimately negatively affects the operation of power plants and the number of emergency outages. A major accident at Petropavlovsk CHP-2 occurred precisely because of the lack of major repairs of the chimney.

The launch of the capacity market was accompanied by the adoption of the Ministry of Energy's decision to reduce the capacity price cap to 590 thousand tenge/MW per month instead of the previously announced capacity tariff price cap of around 700 thousand tenge/MW per month. In addition, the electricity price caps in 2019–20 excluded profit margins. Altogether, these decisions had a negative impact on attracting investment into Kazakhstan's generating assets.

The effect that the centralised capacity trade has had on the capacity price reduction is limited to 0.1%, which generally makes competitive capacity selection meaningless, see Table 8.2. The lack of capacity market vision and goal setting reduces this mechanism to the re-distribution of capacity revenue between the power plants.

In February 2023, the Agency for the Protection and Development of Competition (abbreviated in Russian as AZRK) analyzed capacity trade and concluded lack of competition based on auctions' results.

Figure 8.10 Single Buyer electricity trading model



The decision to launch the capacity market with the price constraints described above, as well as the administratively capped annual amount of funds[14] that could be used for the modernisation and overhaul of the power assets at individual tariffs have resulted in a significant reduction in the level of investments into the power plants since 2019.

An alternative to the current situation in the capacity market could be an increase in the electric power price caps and competitive capacity selection, for example, with the required characteristics and technological parameters of equipment operation.

Over the past decade, the power generating sector has been the testing ground for a variety of tariff policies: from the free market price formation to the introduction of the "tariff-in-exchange for investment" scheme, from setting the price cap without profit margins to the inclusion of the cost of renewable energy into the price caps, and finally singling out the allowances within the price caps that support the use of renewable energy.[15]

To ensure the progressive development of the electric power industry it is important to define the long-term tariff policy and assign the powers relating to the setting and approval of all tariffs in the electric power industry to a single state body. For this reason, it seems logical to create a single Industry Regulator that would combine the functions and set the tariff policy for all energy sectors: electric power, heat energy and heat energy supply.

8.2.7 Cooperation with adjacent power systems

Currently, the energy system of the Republic of Kazakhstan operates in parallel with the Unified Energy System (UES) of the Russian Federation (UES Russia) and the Unified Energy System of Central Asia (Kyrgyzstan, Uzbekistan and Tajikistan).

Taking into account Kazakhstan's plans to develop generating capacity, including renewable generation, as well as accounting for the current lack of sufficient volume of flexible generation the development of regional cooperation with adjacent energy systems is critical for the country's energy security.

Currently, Kazakhstan's power shortages are met by Russia; power supplies from the Kyrgyz Republic in summer traditionally take place in exchange for water for the irrigation of the southern regions of Kazakhstan.

Notably, when it comes to exploring the opportunities for regional cooperation and the cross-border power trade Kazakhstan is already participating in the creation of following two markets:

1) The common electricity market of the Eurasian Economic Union (EAEU)
2) The regional electricity market of Central Asian countries (CAREM - Central Asia Regional Electricity Market).

The common electricity market of the Eurasian Economic Union is being formed as a regional market of five EAEU member states (the Republic of Armenia, the Republic of Belarus, the Republic of Kazakhstan, the Kyrgyz Republic, and the Russian Federation). Considering that the EAEU member states have quite different designs of the wholesale electricity markets the parties agreed to preserve the existing national electricity markets when forming the EAEU common electricity market. It is planned that the common EAEU electricity market will be launched on January 1, 2025.

The power trading between the common EAEU electricity market participants will be in a form of:

Table 8.3 Capacity market 2019 – 2023

	billion tenge				
	2019	**2020**	**2021**	**2022**	**2023**
Modernisation and expansion	9.3	22.5	20.5	19.4	23.1
Purchase from CHP	17.6	16.7	17.1	18.1	20.2
Centralised trading	35.2	43.3	41.9	48.9	48.6
Total purchase volume	62.1	82.5	79.6	86.4	91.9
Cost reduction as a result of a centralized trading, bln. tenge	2.86	0.97	0.30	0.09	0.04
As a percentage of the market	8.2%	2.2%	0.7%	0.2%	0.1%

1) free bilateral agreements;
2) centralized trading of derivative contracts (week, month, quarter, year) and day ahead;
3) hourly settlement of the real time power balance flows from the planned values.

Medium-term EAEU member states energy balances' forecasts to 2030 show the Kyrgyz Republic electricity shortages (according to the Ministry of Energy of the Kyrgyz Republic, the annual electricity shortage in the country is about 3 billion kWh).

14 The National project for the development of the electric power industry Measure 1. Increasing the limit on the permissible volume of attracting investments within the framework of investment agreements of energy producing organizations for the modernization, expansion, reconstruction and (or) renewal of power plants within the framework of the electric capacity market from the level of investment in the electric power industry in 2015.

15 The transition to a Single Purchaser of Electricity eliminated the need to introduce surcharges for renewable energy sources into marginal tariffs.

When it comes to assessing the prospects for the development of this regional association, it is important to emphasize that its infrastructure (the interstate power transmission lines) which is used as a foundation for this market has not received significant development, which may become an obstacle to increasing the power supply along UES Russia-UES Kazakhstan – UES Central Asia (Kyrgyzstan) route in the future

The development of regional power trade amongst the Central Asian countries has its own specifics as the countries in the region have different primary resources to meet the energy load. Thus, the Kyrgyz Republic and the Republic of Tajikistan have significant water resource potential, the Republic of Kazakhstan and the Republic of Uzbekistan have both traditional resources to meet the load – coal and gas, as well as ambitious plans to increase renewable generation.

The following circumstances hinder the full development potential for regional cooperation and scaling up of electricity supply between the countries:

- Currently, Kyrgyzstan's power industry is energy-deficient and it would be necessary to increase the power supply from the neighboring countries in the medium term. The government of the country believes that the energy supply problem would be resolved by building hydroelectric generation (small and large hydroelectric power stations), as well as the development of renewable energy. According to experts, the construction of large hydropower plants (for example, Kambarata HPP-1) will take approximately 10 years, subject to stable financing;
- Tajikistan is currently a power exporter in the region and supplies electrical energy to Uzbekistan and Afghanistan from spring to autumn. The only power sector project which could significantly affect the development of its export potential is the construction of the Rogun HPP;
- The capacity mix in Kyrgyzstan and Tajikistan is not balanced, the power production depends on the water regime. This presents a challenge with the power supply in the autumn-winter period;
- Tajikistan continues to operate in isolation from the Central Asian UES (the country exited the agreement on the parallel operation in 2009), which negatively affects the possibilities for the power exchange. It is worth noting that work to restore the parallel operation is in its active phase. August 2023 marked the completion of the works in the southwestern direction. It is expected that full parallel operation will be restored in April 2024;
- The Southern Energy zone Kazakhstan's energy system is currently energy deficient and, according to the approved forecast balance, will remain deficient in the coming years. Notably, the Southern Energy zone is a leader in the development of renewable generation in the country. Given the lack of flexible generation in Kazakhstan, the country is potentially interested in expanding cooperation with the neighboring countries to solve the problem of reliable energy supply to its consumers;
- Uzbekistan has set ambitious goals to increase its renewable generation. The country's leadership has aims at increasing RES capacity to 15 GW by 2030 and bringing their share in the total power production to more than 30 percent. At the same time, according to the data provided in the “Concept of supplying the Republic of Uzbekistan with electrical energy in 2020-2030,” the average power production growth in 2012–2019 registered 2.6 percent per year. However, the power demand has not been met fully registering 9.4 percent supply shortage. Another aspect that creates difficulties in ensuring a reliable power supply in Uzbekistan is the inability of the country's gas transportation system to meet the demand from the power companies at any time;
- the most difficult issue in energy cooperation between the countries of the Central Asian region has traditionally been the interdependences between the water sector and the electric power complex.

One of the most important and promising projects in this direction is the construction of Kambarata HPP-1 (Kyrgyz Republic). In January 2023, the heads of the energy departments of the Kyrgyz Republic, the Republic of Kazakhstan, and the Republic of Uzbekistan signed a joint roadmap for the construction of Kambarata HPP-1. Summer 2023 demonstrated the importance of joint efforts in implementing this project, when due to abnormally high temperatures and low water periods, agricultural crops were “lost” in the south of Kazakhstan and in some regions of Kyrgyzstan.

In the context of stalling of the regional dialogue on water and energy issues, the solution to the problem of functioning of the Lower Naryn hydro cascade (Kyrgyz Republic) could be the commissioning of new generating capacities, namely Kambarata HPP-1 and HPP-2 in Kyrgyzstan. Located in the middle course of Naryn river above the Toktogul reservoir, these hydro power stations will be independent from the irrigation restrictions and would be able to operate in energy mode all year round. It is believed that this will allow the Toktogul hydroelectric complex to return to normal irrigation mode of operation and accumulate winter water for the needs of the growing season in the neighboring republics.

Based on the current state of the electric power industries of the adjacent energy systems one of the most promising directions for Kazakhstan's power supply could be the Kyrgyz Republic.

Based on the above, there are clear prospects for the regional cooperation in the Central Asian region, moreover, the countries themselves express such interest. Based on the current state of the power industries' development in these countries, the most promising areas of cooperation in the region may be:

1) resolving the water and energy issues through the implementation of joint investment power projects - the construction of new large hydro power plants capable of providing electricity and flexible energy, which is a necessary requirement accounting for the plans to develop renewable energy in the region, but also ensuring water supply in the required volume for the needs of irrigation in the region;
2) strengthening the energy connections in the region is a necessary factor for increasing the volume of electricity supply between the countries. The interstate power network infrastructure needs to be modernized, and accounting for the large power generation investment projects at the regional level it is necessary to identify the projects facilitating reinforcement of the interstate power lines;
3) existing possibilities for the development of regional trade will

Table 8.4 Number of employees by age in the industry.

Age	16-24 years old	25-28 years old	29-34 years old	35-44 years old	45-54 years old	55-64 years old
Qty	7093	9120	30189	41130	30648	22826
%	5%	6%	21%	29%	22%	16%

contribute to the development of market mechanisms between the countries; among the promising areas, in addition to the traditional supply of power between countries is the development of intersystem services, which might become a necessary condition for increasing the variable RES generation in the region.

8.2.8 Heat energy supply

In Kazakhstan the electric power industry[16] also includes the heat energy sector, since 60% of the heat energy is produced by the power plants (CHPs). The cogeneration of electricity and heat energy by TETs in Kazakhstan falls under dual regulation by both the Ministry of Energy (that sets the price caps for the electric power) and by KREM that sets the heat energy tariffs.

Due to the social significance of prices for the heat energy, the state, through KREM, curbs the tariffs growth by setting tariffs lower. At the same time when CHPs heat energy tariffs are capped they face the price competition from the coal-fired CPPs (GRES). The electrical efficiency of electricity production at CPPs (GRES) is physically higher than that at CHPs, but the fuel energy utilisation ratio at CHPs is 70–80% due to the associated heat energy production. The efficiency of using CHPs instead of a combination of a boiler house and a CPP(GRES) has been proven scientifically and empirically by the fact that the total resource costs at CHPs are lower for heating and power supply purposes in the northern cities with a population of more than 100 thousand people.

Unlike the electric power industry the heat energy supply involves three variables: production, transportation (inclusive of the distribution and supply of heat energy) and consumption of heat energy.

The heat energy market operates at the retail level only, at that, in practice consumers are unable to choose their heat energy suppliers. The heating networks and the boiler houses tend to be on the balance sheets or under management of municipal authorities. This way they are forced to make direct investments into updating the heating networks infrastructure.

A separate law "On the Heat Energy Sector" has been under development for more than two years. It aims at singling out the regulation for this industry and optimizing the planning of heat loads and operating modes of the heating networks.

Setting heat energy tariff caps at cost or below production costs means that power plants lack resources to implement energy efficiency and modernization projects (unless the latter are included into investment projects through the capacity market).

The seven-year tariff caps should send long-term price signals to investors; instead they are constantly revised and fail to account for the inflationary growth in costs for fuel, equipment and wages. In general, these issues are common to the regulation of natural monopolies, although the heat energy tariff appears to be suppressed most.

It is necessary to understand that the increase in the volume of repairs and level of heating networks modernisation requires either direct government funding, as municipal budgets are insufficient, or raising heat supply tariffs to their true values. To offset the consequences of rising heat supply tariffs for the residential consumers (population) it would be important to introduce a system of preferential tariffs. As an option, the introduction of a "social housing norm" (about 45 m2 per person) can be considered. If a household, accounting for the number of residents, falls within this norm the heat supply tariff is less than the approved one, and if it exceeds, then the tariff is correspondingly higher than the approved one. Other approaches to differentiation of heat supply tariffs are also possible.

8.2.9 Workforce policy

One of the systemic problems that negatively affects the state of the industry is the lack of qualified workforce. The reasons for this situation in the industry are both the retirement of existing professionals and insufficient intake of new workforce wishing to become professional power sector employees. According to the official data, the staff turnover rate in the 2nd quarter of 2023 in the power supply sector was 8.5%. In comparison, the same figure for the related sector Mining and Quarrying is 5.2%.

For a long time, one of the main reasons for staff turnover was low wages, which contributed to the outflow of specialists to other industries. However, the draft law "On introducing amendments and additions to some legislative acts of the Republic of Kazakhstan on the implementation of certain instructions of the Head of State", made changes to Article 22 of the Law of the Republic of Kazakhstan "On Natural Monopolies" in 2022. In particular, paragraph 1) was supplemented by subparagraph 9-1) with the following content:

«9-2) changes to the average monthly salary by type of economic activity, formed, according to the statistics, for the year in the region (region, city of republican significance, capital), in which the subject of a natural monopoly provides regulated services provided for in subparagraphs 3), 4) and 14) paragraph 1 of article 5 of this Law;».

16 The efficiency of electricity production of CPPs is always higher than that of CHP plants, however, due to additional heat production, CHP plants have an extremely high fuel utilization rate.

By mid-2023, the majority of the country's network companies took advantage of this amendment, which was regulated in more detail in a derivative legal act.

At the same time, the influx of new workforce is limited as the poor financial prospects deter young specialists from choosing the energy sector as a field of study, or, after graduating, they work outside their specialty.

See below statistics[17] for 2022 on the people employed in the electricity and gas supply, and air conditioning , by age:

Notably, about 70% of industry workers are aged 35 years and older, despite the fact that the average age in the sector is 41-42 years.

One of the possible solutions is to increase the number of educational grants in the energy industry by 30%, as well as the introduce requirements for personnel optimization under incentive tariff regulation, and simultaneous introduction of special rates applicable to the growth of employees' salaries. Salaries in the electric power industry should be one and a half to two times higher than the average salaries in the corresponding region or city.

8.3 Industry reform and energy transition

Since 2014, renewable energy has been at the core of Kazakhstan's "energy transition" with a reduction in the share of coal generation, however the focus on the development of wind and solar power plants over time have lead to the imbalances and an increase in the need to balance the operation of unstable energy sources by the Russian energy system. To ensure energy security capacity adequacy and availability of reserves to cover the load as well as to self-balance the energy system would be essential.

In 2022 Kazakshtan announced plans for the construction of two power units at Ekibastuz GRES-2 and the construction of a new power plant at Ekibastuz GRES-3. In 2023, President K. Tokayev proposed to hold a national referendum on the construction of a nuclear power plant in Kazakhstan. If the referendum takes place and the people of Kazakhstan decide to commission nuclear generation in Kazakhstan, there is a possibility to commission two nuclear units with a total capacity of up to 2800 MW.

The plans for the construction of the second line of Beineu-Bozoy-Shymkent gas pipeline and the construction of a number of flexible gas energy sources in the south of the country[18] are the first stage of the energy system gasification.

The international stance on Russia and the EU sanctions against it means Russia is gradually re-routing natural gas transportation from Europe to the Asia-Pacific region. One of the consequences of this re-routing could be the construction of a gas pipeline from Russia to eastern Kazakhstan with the subsequent gasification of coal-fired boiler houses and CHPs, for example the gas pipeline project "Barnaul – Rubtsovsk – Semey – Ust-Kamenogorsk with a branch to Pavlodar".

In reality, the main focus of the power sector transformation is already shifting from the intermittent energy sources (wind and solar power plants) to gasification of coal power plants and boiler houses and the construction of nuclear power plants, as well as the replacement of coal power units with new coal technologies.

To implement new energy projects and modernise the industry, it is necessary to reform the industry.

Proposals for the industry reform:

Power generation

- Develop methodology for calculating capacity tariffs for modernised, expanded and newly commissioned power plants;
- Include modernization costs of auxiliary equipment, infrastructural buildings and structures into capacity tariff;
- Include BAT related costs into capacity tariff
- Increase the volume of power plants undergoing modernization by the means of the capacity market.

RES support

- Re-adjust plans for the commissioning of renewable energy sources with higher priority for the commissioning of hydroelectric power stations;
- Update data on the hydropower potential of Kazakhstan's rivers;
- Plan ahead and allocate sites for hydroelectric power station projects during auctions.

Market Council

- Expand the composition of the Market Council to include consumers, industry experts and other stakeholders on an ongoing basis;
- Empower Market Council with the functions of developing and approving regulation on the operation and policy making for the power plants.

Electricity market

- Include other cost items into the power plants' tariff cap (costs associated with the greenhouse gas emissions) to be accounted for during the purchase electricity from them by the Single Electricity Buyer.

Single Electricity Buyer:

- gradual automation and digitalization of the Single Electricity Buyer operations with the introduction of the principles of multi-criteria optimization during unit commitment;
- Single out and distribute areas of responsibility between the infrastructure organizations - RFC for RES LLP, KOREM JSC, KEGOC JSC at a legislative level ;
- create the Single Electricity Buyer Reserve Stabilization Fund as soon as possible to solve the issues with late payments and cash gaps.

17 https://stat.gov.kz/official/industry/25/statistic/5.

18 CCGT Turkestan, CCGT Kyzylorda, CCGT based on the Almaty Thermal Power Plant and the project currently being considered for the construction of a CCGT plant in Shymkent.

Regulation of natural monopolies

To encourage natural monopoly entities to switch to incentive tariff setting, it is necessary to include the following requirements:

- natural monopolies should have the right to retain up to 50% of the profit and use it at their own discretion, while the rest of the profit should be used for ROI purposes;
- profit, following RAB regulation, should be calculated as a product of WACC and the assets base, at that costs of equipment repairs can be partially included in the assets base.
- a uniform minimum WACC rate should be set for all subjects;
- if a natural monopoly fails to achieve the approved target indicators fines are imposed on the entities' own profit, right down to reducing it zero;
- the tariff is approved once every 5 years and is not revised downward, therefore, the cost savings are retained by the entity;
- the ability to interchange cost items.

To ensure the effectiveness of the transition to the incentive tariff it is necessary to strengthen control over natural monopolies and conduct independent audits of the efficiency of costs and investments, as well as operating activities. For KREM to get financing of this activity a special tariff surcharge applicable to all subjects that fall under natural monopolies regulation could be introduced.

An absolute requirement in the implementation of the above reforms and plans for the development of the electric power industry would be the increase in electricity and heat energy tariffs. To smooth out social factors and the consequences of rising tariffs we recommend to use and combine several approaches:

- direct partial payment of electricity and heat energy bills for the most socially vulnerable segments of the population, subject to compliance with energy consumption standards;
- large (more than 3 levels) differentiation of tariffs according to consumption norms which will also incentivise energy saving;
- increased share of costs cross-subsidization for population at the expense of other groups of consumers, primarily state budget funded organizations.

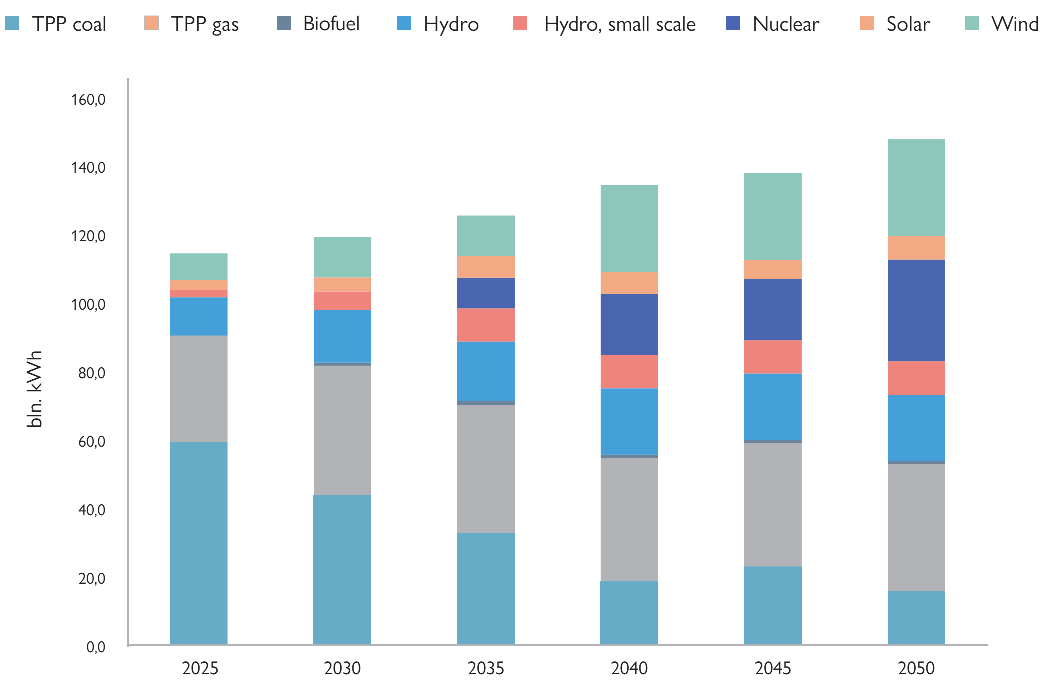
When planning measures to offset costs associated with rising electricity and heat energy tariffs for the vulnerable groups of population we recommend avoiding direct monetization of benefits.

Monetization of benefits has the following disadvantages:

- difficulty with estimating the sufficient amount of compensation for benefits;
- social discontent by the social strata of the population that are not classified as vulnerable but are "borderline" and could feel the impact of rising tariffs significantly;
- lack of guarantees that allocated funds would be directed to their intended purposes;
- rising inflation.

The first step in reforming tariff-setting should be the resolution of social issues and the development of combined approaches to minimise the impact of rising tariffs for socially vulnerable segments of the population.

Figure 8.11 The structure of electricity generation by power plants in Kazakhstan in 2025–2050.



8.4 Electric power industry development forecasts

The forecast for the development of the electric power industry in Kazakhstan calculated in the previous publication of this report (NED 2021) remains generally relevant.

The TIMES electricity forecast was developed as part of the IEA-ETSAP methodology for energy scenarios for an in-depth energy and environmental analysis (Loulou et al., 2004). The forecast made in 2021 assumed a balanced development of generation for the long term, both renewable sources and gas and nuclear generation. The forecast in this report has been adjusted to account for the time it would take to build nuclear power plants and the plans for commissioning coal-fired capacity.

It is important to note that the development of coal-fired generation through the replacement of outdated power units with modern power units with ultra-supercritical steam parameters (USCP) will reduce specific fuel consumption and greenhouse gas emissions by 15-20%.

As a result, in the long term until 2050, we recommend the following balanced approach to the development of power generation in Kazakhstan,:

- replacement of coal power plants with modern coal power units with USCP;
- gradual conversion of coal-fired boiler houses and CHPs to natural gas;
- construction of several nuclear power plants with a total capacity of at least 4 GW;
- development of renewable energy and hydropower, including counter-regulatory hydroelectric power plants.

This forecast is aligned with the low-carbon development goals outlined in Kazakhstan's Carbon neutrality Strategy to 2060.

CHAPTER 9

NUCLEAR ENERGY AND URANIUM INDUSTRY

9. NUCLEAR ENERGY AND URANIUM INDUSTRY

AVANTGARDE ADVISORY AND SEEPX ENERGY

9.1 Key points

► Since the early 2000s, Kazakhstan has increased uranium production twelvefold. Kazakhstan's second place in the world in terms of uranium reserves, availability of technology and effective management of the national company allowed it to attract significant foreign investment in the industry and ensure the first place in the world in uranium mining.

► Kazakhstan currently accounts for about 42% of global uranium production, although it is important to note the overall decline in global uranium production (by 17% over 10 years). Uranium production has also decreased in key mining countries: in Australia by 28% and in Canada by 21%. The decrease in uranium production is compensated for by uranium reserves and the use of accumulated stocks of weapons-grade uranium and plutonium.

► Uranium prices show stable growth. Thus, in September 2023, the spot market price reached US$70 per pound of uranium. The growth of uranium prices is related both to geopolitical unrest against the backdrop of the coup in Niger and the military operation of the Russian Federation, and to the long-term trend towards the expansion of nuclear energy generation capacity in the world.

► According to our estimates, the implementation of plans to build nuclear power plants in the world will lead to a 1.5-fold increase in uranium consumption by 2035, and according to the World Nuclear Association, uranium demand will double by 2040. However, it is uranium that presents an important challenge that is difficult to comprehend in the current market environment - the finiteness of the resource. Despite the fact that Kazakhstan ranks second in the world in terms of uranium reserves, at the current level of production the reserves will be practically exhausted in 25-30 years. Rising demand and uranium prices are stimulating the growth of uranium production in Kazakhstan, where it is technologically easier to increase production, but this makes the problem of depleting uranium reserves even more urgent. In 2022, due to rising uranium prices, the net profit of the national nuclear company NAC Kazatomprom JSC doubled. In our view, it is strategically important to allocate a significant portion of the national company's profits to increase exploration and address long-term planning issues, taking into account the possible transformation of the nuclear fuel cycle.

► As uranium reserves are exhausted and the price rises even more, the nuclear fuel cycle will most likely start to be restructured through more plutonium-fueled fast reactors and the use of thorium.

► 2022, the first batch of fuel assemblies (FA) was shipped and accepted by a nuclear power plant in China. The production of the final components of nuclear fuel is a complex high-tech production process and the construction of a fuel assembly production plant in Kazakhstan is a significant achievement. The commissioned fuel assembly production capacity allows to increase the production load of Ulba Metallurgical Plant for nuclear pellets, the production of which has increased more than eightfold since 2016.

► In 2023, an important political event took place - the President of Kazakhstan K. Tokayev proposed to put the issue of NPP construction to a referendum. If the referendum results are positive, nuclear power could become an important element of the transition to a "green" economy.

9.2 Uranium production and reserves

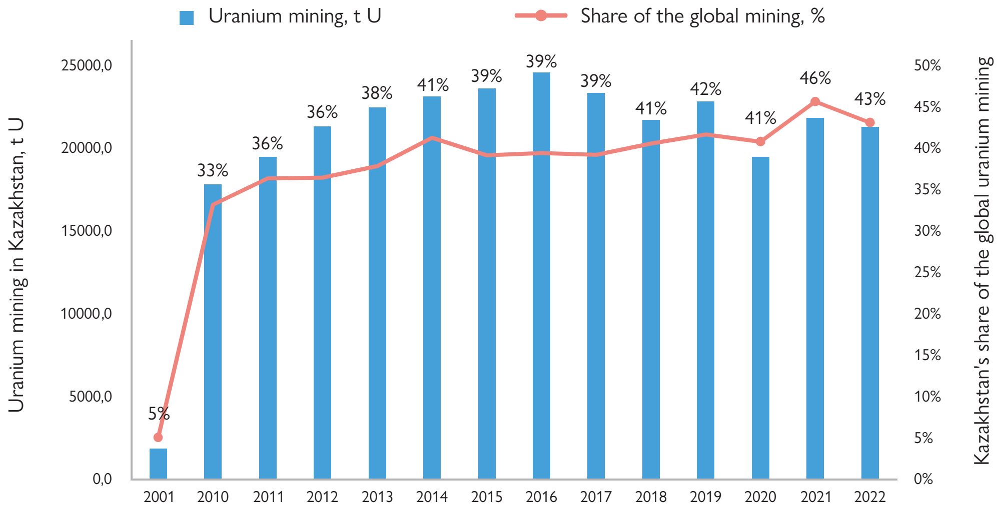
NAC Kazatomprom JSC, a national uranium mining company and operator of uranium and nuclear fuel exports, operates 26 uranium deposits through its subsidiaries and joint ventures. A common feature of all Kazakhstani uranium deposits is that they are mined from sedimentary (sandstone) deposits using in-situ leaching (ISL). This technology was developed independently in the USSR and the USA in the mid-1970s. The ISL technology is a more cost-effective and less environmentally harmful method of uranium mining compared to traditional (mine) methods.

Uranium mining using the ISL method involves injecting leachate (1-2% sulfuric acid (H_2SO_4) solution) into the permeable ore body through a system of injection wells. Drilling is currently carried out to depths of no more than 750 meters, but deeper horizons may be developed in the future. The leaching agent dissolves the uranium and the sulphuric acid "production solution" (containing less than 0.1% uranium) is then extracted through a network of extraction wells and subjected to primary treatment where the uranium is separated using ion exchange resins before it is ready for conversion and enrichment. The ISL technology offers significant advantages over traditional ore mining methods (mine and open pit) in terms of both cost and environmental impact. Since uranium is extracted without removing the host rock and overburden, the capital investment for ore extraction is significantly reduced while minimizing operating costs. This method of mining also has a comparatively lower environmental impact. No dumps or waste rocks are formed, radon emissions are minimized and no toxic dust is generated. There is no need to dispose of the production solution, as it is pumped back into the injection wells for reuse (i.e. re-injection into the ore body) after it has been recovered using an oxidizer and a complexing reagent. This significantly reduces water and sulfuric acid consumption. Groundwater contamination is facilitated by maintaining a pressure differential at the wellhead, ensuring a uniform flow to the deposit or ore body from a nearby aquifer and preventing drilling fluids from entering the mine area.[1] Thus, uranium mining using the ISL method minimizes the environmental impact.

Over the last ten years (from 2013 to 2022), the company's annual uranium production reached 24.7 thousand tons of uranium, and by 2022 it decreased to 22.2 thousand tons of uranium. However, rising uranium prices caused both by the general political instability in Niger (4-5% of global production) and the risks of limiting the supply of nuclear fuel from Russia will

1 Monitoring wells are installed above, below and around the mined layer of the mine and allow monitoring of drilling fluid flows within the allowable development areas.

Figure 9.1 Uranium mining in Kazakhstan and its share in global production



contribute to the increase in uranium production in Kazakhstan.

In September 2023, the uranium price exceeded US$70 per pound of U_3O_8 oxide and approached the price reached before the Fukushima Daiichi accident (US$73 per pound). In September 2023, the uranium price exceeded $70 per pound of U_3O_8 uranium oxide and approached the price reached before the Fukushima Daiichi accident ($73 per pound of U_3O_8 uranium oxide). It is important to note that further aggravation of the conflict in Ukraine brings additional uncertainty to the development of nuclear energy, which is heavily dependent on Russia, whose share in uranium supply is 14%, in uranium conversion (conversion of uranium into UF6) - 27%, and in uranium enrichment - 39%. Political uncertainty determines the volatility of uranium prices, but the long-term trend of demand growth with certain supply limitation will lead to uranium price growth.

The decline in production in the key countries of Australia and Canada in 2013-2022 was due to relatively low uranium prices, which are often unprofitable for uranium mining using traditional methods. Reduced uranium consumption was also caused by the accident at the Fukushima Daiichi nuclear power plant and the shutdown of some reactors in Japan and Germany. However, since then, an increasing number of countries are planning or already building nuclear power plants. As a result, the world market's uranium needs will grow 1.5 times by 2035, and the World Nuclear Association estimates that uranium needs will double by 2040.

Given the current market conditions, growth in profits from uranium exports should be expected. Thus, in 2022, the profit of NAC Kazatomprom JSC more than doubled to 472.5 billion KZT ($1.02 billion), while the revenue from uranium sales increased by 40%.

The prospects for growth in profits from uranium mining, as well as the need to secure uranium supplies, will most likely lead to an increase in Kazakhstan's production to 26,000-28,000 tons of uranium per year. It is important to note the energy value of

Figure 9.2 Price dynamics for U_3O_8 uranium oxide.

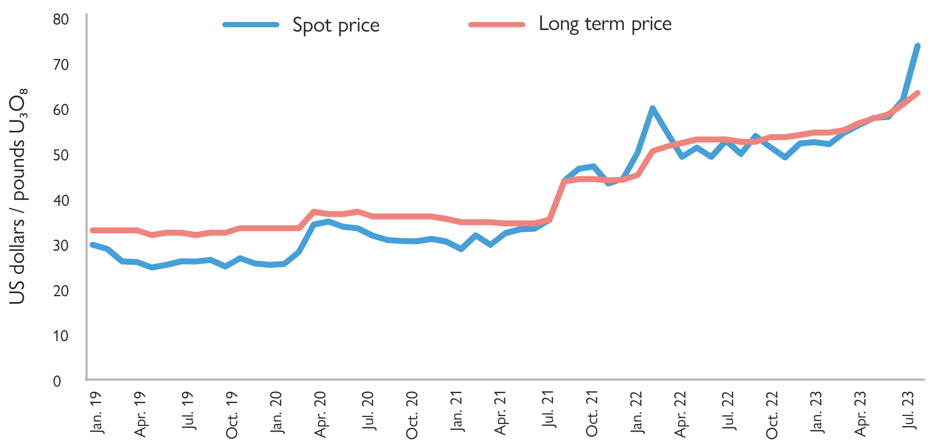
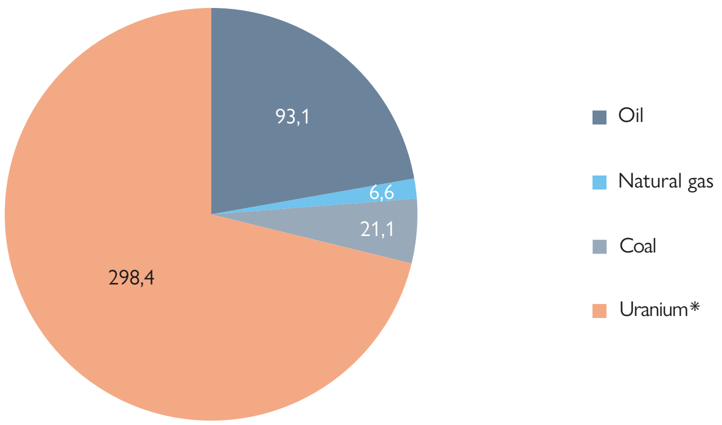


Table 9.1 World uranium production 2013-2022, tons of uranium.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	%
Kazakhstan	22451	23127	23607	24689	23321	21705	22808	19477	21819	21227	-5.5%
Canada	9331	9124	13325	14039	13116	7001	6938	3885	4693	7351	-21.2%
Namibia	4323	3255	2993	3654	4224	5525	5476	5413	5753	5613	29.8%
Australia	6350	5001	5654	6315	5882	6517	6613	6203	4192	4553	-28.3%
Uzbekistan	2400	2400	2385	3325	3400	3450	3500	3500	3520	3300	37.5%
Russia	3135	2990	3055	3004	2917	2904	2911	2846	2635	2508	-20.0%
Niger	4518	4057	4116	3479	3449	2911	2983	2991	2248	2020	-55.3%
China	1500	1500	1616	1616	1692	1885	1885	1885	1600	1700	13.3%
India	385	285	385	385	421	423	308	400	600	600	55.8%
Other countries	4938	4302	3168	2701	2092	1833	1320	1131	748	483	
World production	**59331**	**56041**	**60304**	**63207**	**60514**	**54154**	**54742**	**47731**	**47808**	**49355**	**-16.8%**

Figure 9.3 Estimation of Kazakhstan's export structure by types of energy resources in millions of tons of fuel equivalent.



*Estimation is made on the basis that 1 ton of uranium can be used to produce 40 million kWh of electricity, which was generated from heat energy with an efficiency of 35%.

uranium, namely its predominant share in Kazakhstan's energy exports (in energy equivalent).

Uranium is a valuable energy resource. While oil and natural gas, once used as fuel, are no longer returned to the fuel cycle, the use of depleted or processed uranium is possible in the nuclear fuel cycle.

The growth of uranium production in Kazakhstan raises, first of all, the issue of long-term planning for the development and increase of uranium reserves.

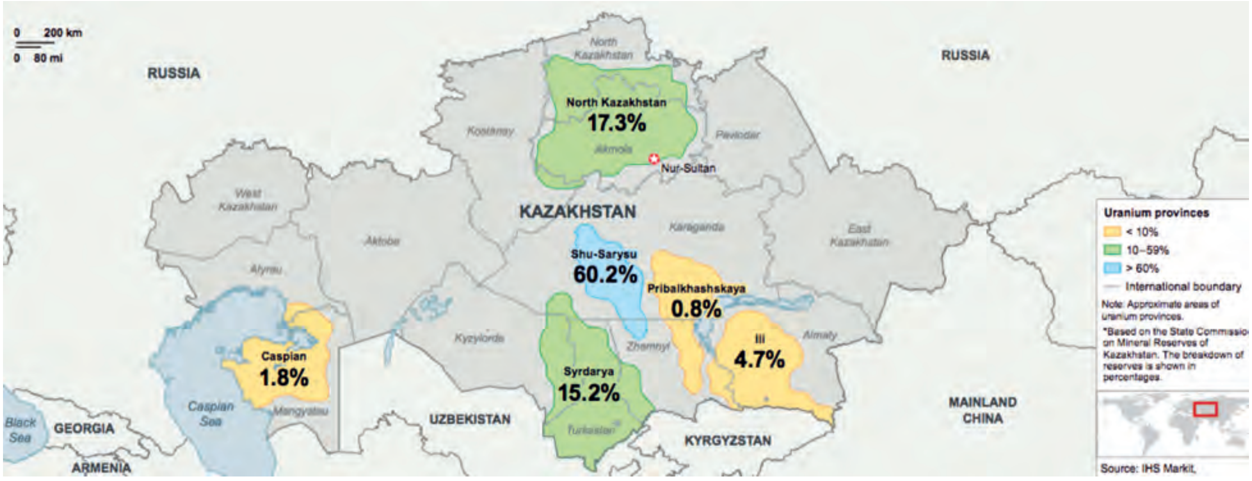
Uranium reserves

The State Balance of Mineral Reserves of the Republic of Kazakhstan lists 56 uranium deposits, of which 6 deposits have only off-balance reserves. Industrial development involves 78.3% of the balance sheet uranium reserves, for which contracts with subsoil users have been concluded.

The division by uranium-ore provinces adopted in the country is shown in Figure 9.4. Within these uranium provinces, the total amount of uranium reserves and resources is more than 1 million tons of uranium. Kazakhstan ranks second in the world in terms of uranium reserves with 13% of the world's uranium reserves.

According to SRK Consulting, ore reserves of all mining enterprises of NAC Kazatomprom JSC as of the end of 2022 amounted to 588.8 thousand tons of uranium, while a year earlier

Figure 9.4 Uranium-ore provinces of Kazakhstan and distribution of uranium reserves.



the reserves amounted to 625.4 thousand tons of uranium. The decrease in uranium ore reserves for the year amounted to 6%.

The table shows that for the majority of NAC Kazatomprom JSC enterprises, mining will be completed by 2050, if there is no increase in reserves. In general, the reduction of uranium reserves is an important fact that should be emphasized, because further increase in production volumes may accelerate the process of uranium reserves depletion.

Delivery diversification

Due to the sanctions pressure on Russia, objective risks of natural uranium transit through the territory and shipment of cargo through Russian ports arose. Therefore, in December 2022, the delivery of natural uranium via the Trans-Caspian International Transportation Route (TITR) to Europe and America was successfully tested. In 2023, uranium shipments via TITR reached 58% in the first half of the year; by the end of 2023, the share of the Company's uranium shipments to Western countries via TITR is expected to reach up to 71%.

Table 9.2 Uranium Reserves and mining in Kazakhstan in 2019 – 2022 by enterprises.

	NAC share, % Uranium reserves, thousand tons	NAC share, % Uranium reserves, thousand tons	Uranium mining, tons U			
			2019	2020	2021	2022
Kazatomprom-SaUran LLP	100%	21.6	1541	1230	1493	1273
RU-6 LLP	100%	12.7	864	660	800	830
JV Inkai LLP	60%	127.7	3209	2693	3449	3201
Katko LLP	49%	51.1	3252	2833	2840	2564
JV YUGHK LLP	30%	75.4	2401	2260	2321	2225
JV Zarechnoye JSC	49.90%	4.2	778	648	655	741
Kyzylkum LLP	50%	34.8	1599	1455	1579	1580
Karatau LLP	50%	35.9	2600	2460	2561	2560
Appak LLP	65%	15.4	800	633	805	803
Ortalyk DP LLP	51%	35.4	1694	1308	1579	1650
Baiken-U LLP	52.50%	15.6	1560	1181	1230	1315
Akbastau JV JSC	50%	36.2	1550	1363	1545	1545
Semizbay-U LLP	51%	8.6	960	753	962	940
Total		**475**	**22808**	**19477**	**21819**	**21227**

9.3 Nuclear fuel production

Nuclear fuel production from uranium includes the following stages: production of natural uranium oxide (U3O8), conversion into uranium hexafluoride, enrichment of uranium hexafluoride to increase the concentration of the U-235 isotope, reconversion of enriched uranium hexafluoride into uranium oxide and production of fuel pellets, and the final stage of the pre-reactor nuclear fuel cycle - production of fuel assemblies. Until recently, the Ulba Metallurgical Plant (UMP) in Kazakhstan had only reconversion and fuel pellet production among these stages of nuclear fuel production.[2]

In 2021, production of fuel assemblies for PWR reactors of French design operated at NPPs in China was launched at UMP. In 2022, the joint Kazakh-Chinese enterprise Ulba-FA LLP producing fuel assemblies delivered the first batch of fuel assemblies containing about 30 tons of low-enriched uranium. By the end of 2023, it is planned to deliver four batches of fuel assemblies to China, which is more than a hundred tons of uranium equivalent, and in 2024 the company plans to reach the full design capacity of 200 tons of low-enriched uranium in fuel assemblies.

Under the cooperation agreements between NAC Kazatomprom JSC and CGN dated 2016, the parties agreed to build a FA production plant located on the territory of UMP JSC. In this case, CGN guarantees the purchase of the plant's products by Ulba-FA LLP, and in return, NAC Kazatomprom JSC agrees to sell a 49% stake in its subsidiary DP Ortalyk LLP in favor of CGN or its affiliated company. The source uranium material for the production of Ulba-FA LLP is UMP fuel pellets, which will allow to utilize UMP's production capacity.

Table 9.3 Volumes of fuel pellets output at UMP, tons

Years	2014	2015	2016	2017	2018	2019	2020	2021	2022
Fuel pellets	10	10	24	75.2	84.3	86	60.3	43.5	198.2

During the Soviet Union, UMP covered about 80% of the fuel pellets demand of nuclear power plants, and the annual production volume was 1200 tons of low-enriched fuel. Since Kazakhstan's independence, the plant's work until 2008 consisted of fulfilling orders from Rosatom to produce fuel pellets for fuel assembly production in Russia. After 2008, Rosatom refused to place orders for the supply of fuel pellets at UMP in favor of its own production. UMP was forced to reorient from high-tech production of fuel pellets to the production of powdered products from various types of raw materials to supply to the fuel element production plants in other countries. In 2011, a Contract for the supply of enriched uranium product (EUP) and the production of ceramic nuclear fuel pellets was concluded with the Chinese company CGNPC; practical implementation of the Contract began in 2016.

Currently, Ulba Metallurgical Plant produces fuel pellets for both Russian-designed VVER reactors and French-designed Framatome PWRs. The production volume of fuel pellets in 2022 amounted to 198.2 tons. Over three years, the production of fuel pellets at UMP increased 2.3 times, which is extremely important to support the production of high-tech products.

9.4 Prospects of nuclear energy in the world

The world's nuclear power plants produced 2,486.8 billion kWh in 2022, which is about 8.5% of global production.

Today, the world's nuclear power industry includes 438 nuclear reactors, which are located in 32 countries and cumulatively produce about 393.8 GW of electricity.

Overall, nuclear power capacity growth has been steady over the past decade, increasing by 20.3 GW(e) between 2012 and 2022, with more than 7.4 GW(e) of new capacity connected in 2022 alone, including 5.8 GW(e) in Asia and 1.6 GW(e) in Europe.[3] In 2022, 3.3 GW (5 reactors) of nuclear capacity was permanently shut down.

The largest fleet of NPPs in the world belongs to the USA. The 93 power units in operation, with a total capacity of 95.5 GW, produce 18.2% of the country's electricity. At the same time, the USA, which is the leader in the nuclear power industry, is practically not planning to build new nuclear facilities, unlike China, which is building the largest amount of nuclear facilities (18.2 GW). As a result, the fastest growing economies in the Asian region, China and India, are taking over the lead in nuclear power.

In recent years, Japan has changed its plans to decommission nuclear power plants and is building new reactors. The government's stated goal is for nuclear power to provide 20-22% of electricity by 2030. In 2011, nuclear power accounted for almost 30% of the country's total electricity production (29% in 2009) with an installed capacity of 47.5 GW, but the accident at the Fukushima Daiichi nuclear power plant halted the development of nuclear power in Japan for a long time and led to the closure of some nuclear power plants.

In general, after the Fukushima Daiichi accident, the requirements for modern reactors were significantly strengthened. "Post-Fukushima" reactors are already so safe that when the cooling circuit is shut down, the reactor stops and cools itself through the action of natural physical principles - passive safety systems.

2 Enriched uranium is supplied to UMP from enrichment plants in Russia: the Ural Electrochemical Plant and the International Uranium Enrichment Center (IUEC) in Angarsk.

Figure 9.5 Capacities (GW) of operating, under construction and planned NPPs.

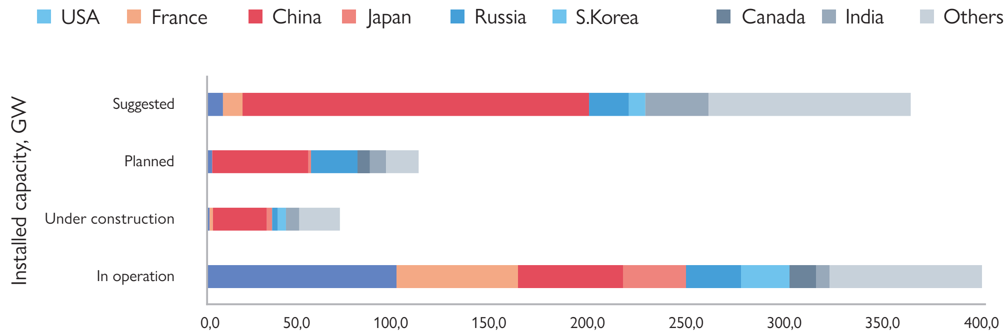


Table 9.4 Types of reactors at NPPs in operation and under construction.

Reactor types	NPP in operation		NPP under construction	
	Capacity, GW	Share, %	Capacity, GW	Share, %
PWR	289.1	78%	52.7	89%
BWR	44.1	12%	2.7	4%
GCR (UK only)	4.7	1%		
HTGR (China)	0.2	0.1%		
PHWR	24.1	6%	1.9	3%
LWGR (Russia only)	7.4	2%		
FBR	1.4	0.4%	2.1	3%

The choice of developing countries towards nuclear power is due to economic and environmental advantages. The environmental impact of NPPs is insignificant compared to coal and even hydroelectric power plants, and their operating life exceeds 60 years, which is many times higher than that of unstable wind and solar power plants. Greenhouse gas emissions during NPP operation are insignificant, so nuclear power is low-carbon.

In terms of reactor technologies, the main focus of NPP construction is on double-circuit thermal neutron reactors with water moderator and coolant (PWR or VVER).

Table 9.4 shows that the share of boiling water reactors (BWRs) at NPPs under construction is much smaller than at operating NPPs. Boiling water reactors (BWRs), consisting of a single circuit, have a number of disadvantages: larger dimensions of the vessels of boiling reactors (by a factor of 2 compared to PWRs), more complex reactor control, as well as radiation contamination of the turbine, and as a consequence, the complexity of repair work.

Due to the low competitiveness of gas-cooled reactors compared to PWRs and BWRs, NPPs with gas-cooled reactors are not planned for construction.

PHWRs fueled by unenriched natural uranium have a number of operational limitations and are also inferior to PWRs and BWRs in terms of their economic performance. New NPPs with PHWRs are being built only in India as part of India's nuclear strategy.[3]

Fast breeder reactors are currently operated only in Russia and in the future are part of the planned construction of a closed nuclear fuel cycle. Currently, NPPs with fast breeder reactors are being built in China and India in addition to Russia. China, like Russia, has plans to build a closed nuclear fuel cycle, and two power units with CFR-600 fast reactor demonstrators are under construction at Xiapu NPP.

Based on operational experience, technical and economic parameters, PWR (VVER) type reactors are the main reactor technology for NPPs under construction. However, the limited resource base is implied by the nuclear power development programs of Russia, China and India. As a result, over time, alternative approaches to the nuclear fuel cycle will become more and more relevant:

- uranium mining from alternative sources;
- transition to uranium-thorium cycle;
- transition to a closed uranium-plutonium cycle.

Seawater, which contains up to 3 mg of uranium in one cubic meter, is also considered as an alternative source of uranium. Possibilities of using depleted uranium with its enrichment are also being considered.

The main limiting factor in these areas is the uranium price. As reserves are exhausted and the uranium price rises, the profitability of alternative sources of uranium will increase.

3 In April 2023, the largest EPR reactor in Europe with a capacity of 1600 MW was launched in Finland, but construction of the reactor had been underway since 2005 and was associated with a number of technical difficulties.

4 the long-term development program of the Indian nuclear power industry focuses on the PHWR (CANDU type), including its subsequent inclusion in the fuel cycle of thorium, of which India ranks first in terms of thorium reserves.

Another approach to replenishing the limited uranium resources is the use of thorium. Thorium is a natural radioactive element. Twelve thorium isotopes are known, but natural thorium basically consists of one isotope Th-232. Thorium reserves are significant and distributed in many countries of the world. Thorium as a fuel for NPPs has an advantage - the possibility of formation of fissile isotope U-233. The transition to the uranium-thorium fuel cycle reduces the need for uranium. The thorium nuclear program is being developed in India, which has significant thorium reserves. Russia has designed a VVER-T reactor using enriched uranium and thorium as fuel. It is possible that the use of thorium as a component of nuclear fuel will help reduce uranium consumption in the future and partially solve the problem of uranium depletion.

Another extremely promising and breakthrough area of nuclear power development is the transition to a closed fuel cycle, which involves the widespread use of fast breeder reactors capable of producing fissile nuclear elements in greater quantities than their consumption. The reprocessing of spent fuel from such reactors makes it possible to replenish the volume of nuclear fuel for both fast breeder reactors and conventional reactors (thermal neutron reactors) with the addition of a small amount of natural or depleted uranium. The need for uranium enrichment would be minimized. According to experts' estimates, in case of transition of nuclear power to a closed fuel cycle, the annual uranium demand will be reduced by more than 200 times.

In terms of creating a closed nuclear cycle, Russia is the closest to these technologies. In June 2021, construction of a nuclear power unit with the innovative BREST 300 fast breeder reactor began in Seversk (Tomsk Region). The new reactor with lead coolant and new mixed uranium-plutonium nitride fuel, optimal for fast neutron reactors, will have an installed capacity of 300 MW. The BREST-300 reactor will be part of a pilot demonstration power complex, which includes three interconnected facilities: a module for the production of uranium-plutonium nuclear fuel, the BREST-300 power unit, and a module for spent nuclear fuel reprocessing. Thus, for the first time in the world practice, a fast breeder NPP and a stationary closed nuclear fuel cycle will be built on the same site. After reprocessing, spent nuclear fuel will be sent for refabrication (i.e., re-manufacturing of fresh fuel) - thus the NPP in Seversk will operate on a closed fuel cycle.

The development of nuclear technologies can solve the problem of depleting uranium reserves and at the same time make nuclear power even safer. Increasing nuclear power capacity will make it possible to replace basic coal-fired power plants in the future and significantly reduce greenhouse gas emissions.

9.5 Kazakhstan's Reactor Selection

In addition to a developed uranium industry, Kazakhstan has substantial experience in operating nuclear reactors. In 1973, Kazakhstan launched a pilot, dual-purpose BN-350 fast breeder reactor with a sodium liquid metal coolant designed to generate steam for both seawater desalination and power generation. Due to the steam generated in the steam generators of the BN-350 reactor plant, the distillate plant fully met the fresh water needs of Aktau city and the region. The design life of the reactor was 20 years, but it was extended and the reactor operated until 1998. In March 1998, the reactor was shut down, and on April 22, 1999, the Government of the Republic of Kazakhstan issued a decree to decommission the BN-350 reactor.

In addition to the decommissioned BN-350 (MAEK) reactor, Kazakhstan's Kurchatov city has a unique research facilities for nuclear research and nuclear power with a large human resource potential. Research centers, including research reactors and test facilities, were built in Kurchatov as part of the Soviet program to develop a high-temperature nuclear rocket engine.

Kazakhstan's leadership since 2009 in the uranium market and the development of uranium industry segments have not yet led to a political decision to build a nuclear power plant (NPP) as the final component of the nuclear industry. However, in the adopted concept of Kazakhstan's transition to a "green" economy, the construction of NPPs is considered on a par with wind and solar power plants as a measure to move away from coal power, the share of which in Kazakhstan's energy sector remains one of the highest in the world. Neighboring Uzbekistan is already planning the construction of the region's largest nuclear power plant with a capacity of 2.4 GW with Generation 3+ reactors and meeting the highest "post-Fukushima" safety requirements.

In 2023, Kazakhstan's President K. Tokayev proposed to put the issue of NPP construction to a referendum. If the referendum result is positive, Kazakhstan will face the issue of choosing reactor technology.

In our opinion, the main criteria for selecting reactor technology should be:

- reactor safety i.e. generation 3+;
- integration into the power system;
- cost and construction time of NPPs with this type of reactors.

Despite the start of the nuclear "renaissance" in the early 2000s, the Fukushima Daiichi accident has affected the development of nuclear technology. Currently, only a limited number of companies have experience in building and operating nuclear power plants with Generation 3+ reactors.

Rosatom has the largest number of operating Generation 3+ reactors. In general, 24 out of 60 reactors under construction are built using Russian technologies, but the sanctions pressure creates certain obstacles to the implementation of NPP projects with Russian reactors.

In terms of integration into the energy system, based on the requirements of the country's energy infrastructure, the construction of NPPs with high-capacity reactors is undesirable, because in case of fuel overload or emergency reactor shutdown, up to 6% of the total capacity will be excluded from the country's energy system. Thus, high-capacity reactors, such as EPR 1600 MW and CAP 1400 MW, are not suitable based on the requirements of reliability and stability of the energy system.

The choice of reactor technology among the remaining three reactor types (AP 1000, VVER 1200 and IPHWR-700) should be made based primarily on technical and economic indicators.

Table 9.5 Generation 3+ reactor technologies.

Reactor name	Developer	Country	Capacity	Number of active reactors
AP 1000	Westinghouse/Toshiba	USA	1117	5
CAP 1400	Westinghouse/SNPTC	China	1400	0
EPR 1600	Orano (Areva)	France	1600	3
VVER 1200 (and other projects)	Hydropress-Rosatom	Russia	1200	7
IPHWR-700	NPCIL	India	700	1

9.6 Nuclear power and low-carbon development

Coal-fired generation dominates in Kazakhstan and unstable energy sources such as wind and solar power plants are not sufficient to replace coal-fired generation capacity as part of low-carbon development. To replace coal-fired power plants, a reliable source of baseload generation with minimal pollutant and greenhouse gas emissions is needed. Nuclear power plants are such a source. Nuclear power plants have a much lower environmental impact than coal-fired power plants.

Despite the fact that coal has been used to generate electricity since the end of the 19th century, it is still the main source of electricity, as it was 100 years ago - the share of coal power in the world balance is about 40%. Of course, it is wrong to compare coal combustion technologies of 100 years ago and now, but nevertheless, there are still factors that have an extremely negative impact on the environment, making coal power the most "harmful" to the environment.

The main negative factor of coal power generation is associated with the emission of sulfur and nitrogen oxides, heavy metals, as well as with the problem of storage of large volumes of ash generated as a result of coal combustion. Emission of sulphur and nitrogen oxides results in acid rain, which has a negative impact on the ecosystem and human health. Emission of heavy metals (including mercury) is a result of their natural presence in fossil fuels. Heavy metals tend to accumulate in the body, producing neurotoxic effects. Radioactive substances present in fossil fuels after combustion of hard coal, lignite or peat remain and are concentrated in the ash. Depending on the coal deposit the concentrations of natural radioactive isotopes in ash exceed the corresponding concentrations in coal by 2 - 15 times, thus, coal ash from some deposits can be referred to radioactive waste. Ash dumps generated as a result of operation of coal-fired power plant with capacity of 1000 MW per year occupy the area of 1.2 - 1.6 million m2 and contain more than 830 thousand tons of solid waste containing up to 90 tons of arsenic and 20 tons of mercury. Ash dumps in combination with arid climate and constant winds, which is typical for Kazakhstan, lead to significant dusting and pollution of adjacent territories. Nuclear power plants, despite the presence of radioactive fuel and waste, are characterized by strict localization of radioactive materials.

From the economic point of view, nuclear power has the lowest dependence of the cost of generated electricity on fluctuations in fuel prices. The economic advantages also include significant operating life of nuclear power plants of more than 60 years, whereas for coal-fired power plants - 40 years, for gas-fired power plants - no more than 30 years. When making a decision to build a nuclear power plant, it is necessary to consider that the nuclear power plant will provide electricity for several generations of the country's residents.

Kazakhstan is considering a wide list of potential sites for NPPs, including the village of Ulken on the western shore of Lake Balkhash, the cities of Kostanai, Kurchatov and Taraz.

9.7 Key findings and recommendations

- Given the increase in uranium mining volumes, it is necessary to increase the share of profits allocated to geological exploration to increase uranium reserves. It is necessary to develop a long-term strategy for geological exploration and uranium reserves growth.
- The launch of the fuel assembly plant is a great achievement for Kazakhstan's industry, and the possibility of increasing nuclear fuel production by expanding production or increasing productivity should be explored.
- The Kazakhstani leadership needs to convince the population of the benefits of nuclear power development, which will be a difficult task given the country's historical experience with the consequences of the extended nuclear weapons tests at the Semipalatinsk test site.
- The choice of reactor technologies is rather limited, but in case of NPP construction the choice should be made only among modern Generation 3+ reactors.

Kazakhstan Association of Oil, Gas and Energy Sector Organizations, KAZENERGY

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