Outlook for natural gas

Blue sky thinking?

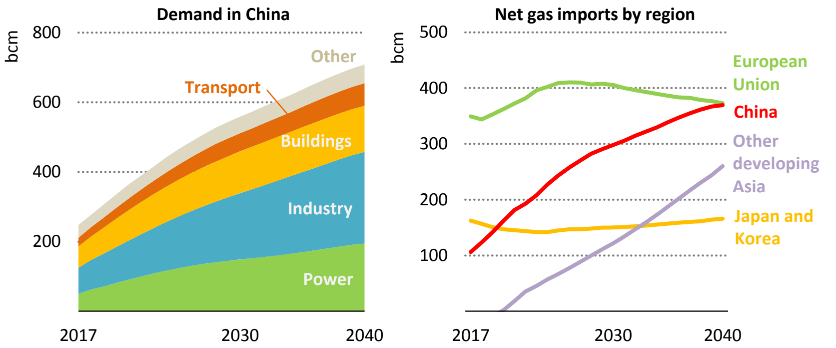
SUMMARY

- Natural gas is the fastest growing fossil fuel in the New Policies Scenario, overtaking coal by 2030 to become the second-largest source of energy after oil. With demand growing by 1.6% per year, gas consumption is almost 45% higher in 2040 than today. Industry takes over from power generation as the main sector for growth.

- China's gas demand triples to 710 billion cubic metres (bcm) by 2040, up 100 bcm compared with our *Outlook* in 2017, mainly due to a concerted coal-to-gas switch as part of the drive to "turn China's skies blue again". China's gas consumption moves from being roughly half that of the European Union today to 75% higher by 2040.

- China soon becomes the world's largest gas-importing country, with net imports approaching the level of the European Union by 2040 (Figure 4.1). It is also on track to surpass Japan as the largest liquefied natural gas (LNG) importer.

Figure 4.1 ▷ Gas demand in China and net gas imports by region in the New Policies Scenario

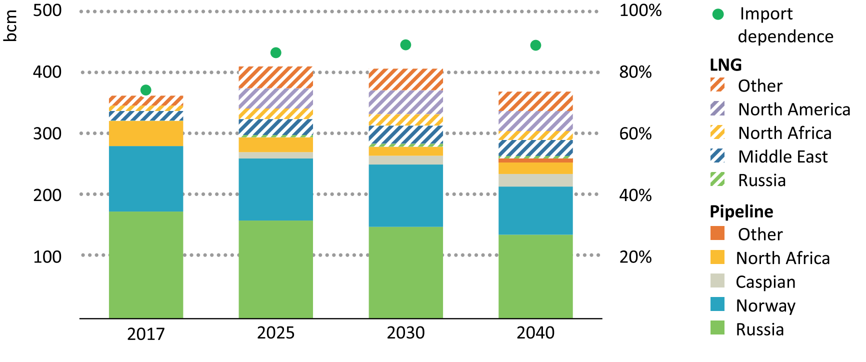


With rising gas demand in all end-use sectors, China's net gas imports approach the level of the European Union by 2040

- In other emerging Asian economies, the prospects for gas differ widely depending on the composition of domestic resources, demand and policies. Demand in India expands steadily to 170 bcm, mainly in power and industry, but the share of gas in the energy mix remains less than 10% in 2040. Demand in Southeast Asia and South Asia doubles, with growth driven largely by industry.

- Emerging economies in Asia as a whole account for around half of total global gas demand growth: their share of global LNG imports doubles to 60% by 2040.
- Unconventional gas increasingly underpins future natural gas supply. Shale gas production expands by 770 bcm in the period to 2040, which exceeds growth in conventional gas production. The United States accounts for 40% of total production growth to 2025. After 2025, additional growth comes from a more diverse range of countries including China, Mozambique and Argentina.
- Growth in global gas trade comes mostly from LNG, with its share swelling from 42% to almost 60% by 2040. LNG import flows continue to go mostly to Asia, while the export picture becomes more diverse with a new roster of suppliers.
- The global gas market comfortably absorbed a recent ramp-up in LNG liquefaction capacity; new LNG investment decisions are starting to come through, but it remains challenging to reconcile buyer expectations of greater flexibility on contractual terms with supplier needs for bankable longer term commitments.
- Gas demand in the European Union has been revised downwards on the back of new targets for efficiency and renewables, but gas infrastructure retains a strong role in ensuring security of supply – especially to meet seasonal peaks in heating demand that cannot be met cost-effectively by electricity.
- Despite lower demand, declines in indigenous production mean that the European Union's import dependence rises to 86% by 2025. Russia remains the largest single source of supply to the region and among the least-cost, but the leverage that this provides is set to wane in an increasingly integrated European gas market in which buyers have access to multiple sources of imported gas (Figure 4.2).

Figure 4.2 ▷ Natural gas imports and dependence in the European Union in the New Policies Scenario



Despite weakening demand, declining gas production suggests increased import dependence in the European Union

Introduction

Surging growth in global gas trade – underpinned by the shale revolution in the United States and the rise of liquefied natural gas (LNG) – continues to accelerate the transformation of gas markets. Although talk of a global gas market similar to that of oil is premature, LNG trade has expanded substantially in volume since 2010 and has reached previously isolated markets. Spot trading, liquidity and flexibility are all on the rise, meaning that gas is more accessible to a wider variety of market players and is more responsive to short-term changes in supply and demand across regions. Together with policy efforts to combat air pollution, these trends have supported growth in natural gas demand in emerging economies in Asia. China in particular has seen very rapid demand growth, overtaking Korea as the world's second-largest LNG importer in 2017, and well on track to surpass Japan.

Asia's emerging LNG importers are varied and are different from more mature markets in the region such as Japan and Korea. China is the closest to the traditional model, securing the bulk of its gas on a long-term basis and receiving it via onshore regasification terminals. Many other importers in Asia seek more flexible, shorter term arrangements to take advantage of current market conditions, and are more reliant on floating regasification to bring gas to market. There is some uncertainty around the position of natural gas in Asia's future energy mix, particularly since several potential new export projects do not look profitable at the price levels that have supported the recent rise in the region's gas consumption. While strong policy efforts may establish gas as a mainstream fuel in the energy system, signs of supply security risks or frequent price spikes could push gas to the margin and increase the prospect of Asian markets relying on a mix of coal and renewables. Uncertainty affects investors too, and only a handful of new liquefaction plants received the go-ahead from mid-2016 until mid-2018. Project approvals have picked up since then, but there are signs that exporters are still searching for commercial models suited to the new market order.

The first part of this chapter presents the key findings on natural gas from the various scenarios, after which we explore three crucial topics for the future of gas in detail:

- What is the outlook for natural gas demand in emerging Asian economies? There is ample scope for further growth in aggregate, but a wide variety of starting points and policy considerations make China, India, Southeast Asia and South Asia quite distinct.
- How will global gas exporters fare in a more competitive gas supply environment? We examine how changes in gas markets are creating new risks and opportunities both for the incumbents and for the burgeoning ranks of new gas exporters.
- What does the future look like for natural gas in the European Union? We explore how the European Union's ambitions for gas security and long-term decarbonisation intersect; what they mean for the future of gas infrastructure; and what the achievement of the "Energy Union" objectives might mean for the gas outlook.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Scenarios

4.1 *Natural gas overview by scenario*

Table 4.1 ▷ Global gas demand, production and trade by scenario (bcm)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Power	907	1 515	1 618	1 981	1 668	2 226	1 602	1 265
Industry	631	872	1 076	1 436	1 089	1 522	1 041	1 221
Buildings	652	802	887	1 014	918	1 133	839	811
Transport	70	131	182	328	168	254	207	408
Other sectors	256	432	531	640	544	712	501	479
World natural gas demand	**2 516**	**3 752**	**4 293**	**5 399**	**4 386**	**5 847**	**4 189**	**4 184**
Share of Asia Pacific	*12%*	*21%*	*25%*	*29%*	*25%*	*29%*	*26%*	*36%*
Conventional gas	2 311	2 918	3 064	3 654	3 153	3 889	3 006	2 899
Tight gas	136	273	238	293	233	302	313	195
Shale gas	22	495	884	1 267	885	1 451	752	919
Coalbed methane	38	74	68	121	75	137	80	112
Other production	-	10	40	63	40	67	38	59
World natural gas production	**2 507**	**3 769**	**4 293**	**5 399**	**4 386**	**5 847**	**4 189**	**4 184**
Share of shale gas	*1%*	*13%*	*21%*	*23%*	*20%*	*25%*	*18%*	*22%*
Pipeline	391	447	491	532	500	657	458	452
LNG	136	323	509	757	518	807	527	627
World natural gas trade	**527**	**771**	**1 000**	**1 289**	**1 019**	**1 464**	**985**	**1 080**
Share of production that is traded	*21%*	*20%*	*23%*	*24%*	*23%*	*25%*	*24%*	*26%*
Henry Hub price ($2017/MBtu)	**6.0**	**3.0**	**3.3**	**4.9**	**3.4**	**5.3**	**3.3**	**3.6**

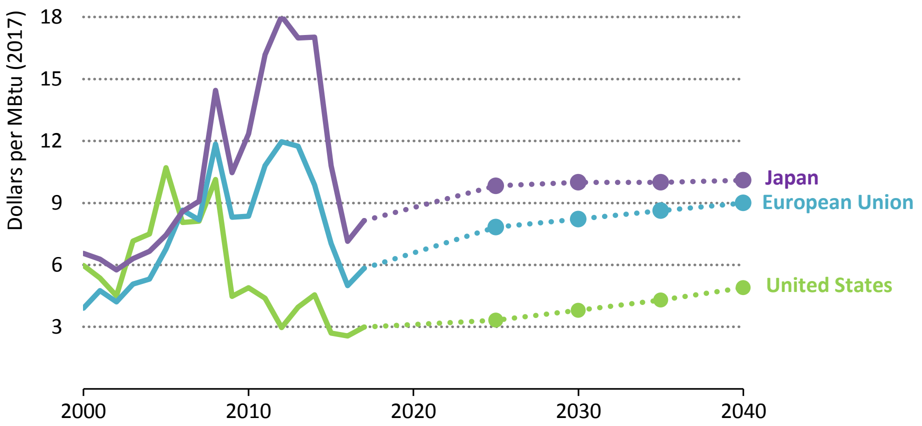
Notes: MBtu = million British thermal units. Unless otherwise stated, use of gas in industry in this chapter includes volumes also consumed in petrochemical feedstocks, own use and transformation in blast furnaces and coke ovens, and gas-to-liquids plants. Historical data for world demand differ from world production due to stock changes. Unless otherwise stated, trade figures in this chapter reflect volumes traded between regions modelled in the *WEO* and therefore do not include intra-regional trade.

In the **Current Policies Scenario**, global gas demand rises by 2% per year, resulting in almost 60% more demand in 2040 than today (Table 4.1). The largest growth in volume comes from the power sector, where gas faces less competition from renewables than in our other scenarios. With higher demand, unconventional gas resources are increasingly called upon. Shale gas production almost triples over the outlook period and increasingly takes place outside the United States, notably in China, Argentina and Canada. As the market resorts to more costly projects, the cumulative required investment in gas supply is 15% higher ($10 trillion) than in the New Policies Scenario, which explains the higher gas prices in this scenario.

In the **New Policies Scenario**, natural gas demand in 2040 has been revised up by almost 100 billion cubic metres (bcm) compared with our 2017 *Outlook*: the bulk of the revision is attributable to China, where gas demand grows rapidly reflecting strong policy efforts to improve air quality. Developing economies in Asia account for half of the total demand growth through to 2040.

The United States accounts for 40% of total gas production growth to 2025, after which sources of growth become more diverse as US shale gas production flattens and unconventional gas production from other regions picks up. Low-cost US production keeps Henry Hub prices relatively low until the mid-2020s, but increasing levels of global LNG trade eventually begin to narrow the gap between regional prices (Figure 4.3). The cumulative required investment for gas supply is about $8.4 trillion, with upstream investment representing two-thirds of the total.

Figure 4.3 ▻ Natural gas prices in key regions in the New Policies Scenario



Growing LNG trade narrows the gap in natural gas prices in key regions

In the **Sustainable Development Scenario**, gas demand continues to grow to 2025 before flattening out at around 4.2 trillion cubic metres (tcm). Gas is the only fossil fuel for which demand in 2040 is higher than today, and it becomes the largest fuel in the global energy mix. The dynamics are different from those in the other scenarios. Gas demand for power generation declines as gas increasingly provides peaking and balancing power rather than baseload generation. Instead, gas increases its share in the industry and transport sectors, where there is a strong impetus to curb the use of more emissions-intensive fuels. Lower demand translates into lower prices as well as lower investment needs for gas supply; the cumulative investment requirements amount to $6.3 trillion.

In more carbon-intensive systems where there is ample scope to displace coal, such as India, gas demand is higher than in the New Policies Scenario. In Europe and North America, demand remains stable to 2025, but declines after that reflecting improved efficiency in buildings and industry, and more rapid decarbonisation of power.

4.2 Natural gas demand in the New Policies Scenario

Table 4.2 ▷ Natural gas demand by region in the New Policies Scenario (bcm)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
North America	800	969	1 078	1 101	1 136	1 170	201	0.8%
United States	669	767	853	869	890	907	140	0.7%
Central and South America	97	174	183	204	236	271	97	1.9%
Brazil	9	36	33	39	51	62	26	2.3%
Europe	606	613	622	611	601	592	- 20	-0.1%
European Union	487	482	472	450	426	408	-74	-0.7%
Africa	56	145	175	211	258	308	163	3.3%
South Africa	1	4	5	6	8	10	6	3.9%
Middle East	174	501	560	646	731	794	294	2.0%
Eurasia	471	575	592	601	617	635	60	0.4%
Russia	388	460	469	468	471	475	14	0.1%
Asia Pacific	313	775	1 073	1 248	1 413	1 579	805	3.1%
China	28	248	464	559	637	708	460	4.7%
India	28	57	94	122	147	171	113	4.9%
Japan	81	120	96	98	102	102	-18	-0.7%
Southeast Asia	88	170	205	229	258	289	119	2.3%
International bunkers	-	0	10	20	33	49	49	32.7%
World	**2 516**	**3 752**	**4 293**	**4 641**	**5 025**	**5 399**	**1 647**	**1.6%**
Current Policies			4 386	4 860	5 366	5 847	2 095	1.9%
Sustainable Development			4 189	4 318	4 298	4 184	433	0.5%

Notes: CAAGR = Compound average annual growth rate. International bunkers are LNG used as a marine fuel.

Global gas demand grew by 3% in 2017, largely driven by strong demand in China. In the New Policies Scenario, demand continues to increase by 1.6% per year, ending up some 45% higher by 2040 from current levels (Table 4.2). Two-thirds of this growth comes from developing economies in Asia and the Middle East.

China accounts for nearly 30% of total demand growth to 2040 in the New Policies Scenario. Demand grows in all end-use sectors, rising almost threefold over the outlook period. As part of the initiative to "turn China's skies blue again", the government has given a strong push to coal-to-gas switching in industry and buildings, and it plans to expand the scope beyond the original "2+26" cities (Beijing, Tianjin and 26 other cities). Gas also plays a bigger role in the power mix to meet surging electricity demand, complementing low-carbon sources. Today, natural gas consumption in China is roughly half that of the European Union, but it overtakes the EU in the mid-2020s and is almost 75% higher by 2040.

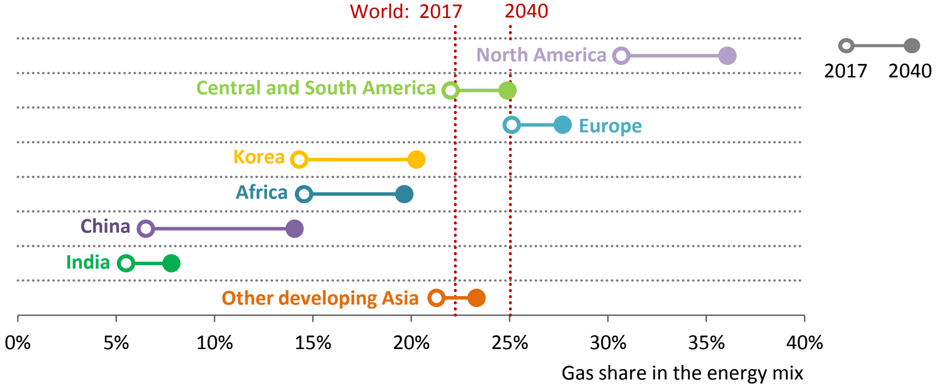
Natural gas demand in **India** expands steadily to 170 bcm, mainly due to the power and industry sectors, but the share of gas in the energy mix remains less than 10% in 2040 in the New Policies Scenario. While the low share of gas today implies huge scope for growth, strong competition from coal and renewables for power generation, the lack of policy measures to push out coal and challenges around infrastructure developments all hamper this potential from being fully realised.

In **Southeast Asia** and **South Asia**, where natural gas already occupies a relatively large share in the energy system, renewables and coal gain shares in the power mix, although gas demand still grows in absolute terms. In particular, demand for gas in industry pushes up overall gas consumption, resulting in gas demand in 2040 almost doubling from today's level (see section 4.5).

The **Middle East** sees growth in gas consumption over the outlook period that is second only to China. A combination of surging electricity demand and scope to displace oil makes the power sector the main source of rising gas demand. There is also substantial growth for desalination and industrial uses. Overall gas demand is 60% higher in 2040 than today.

Natural gas demand in **Africa** more than doubles in the period to 2040. The primary driver is gas use for power generation, followed by desalination and industrial uses.

Figure 4.4 ▷ Share of gas in the energy mix by region in the New Policies Scenario



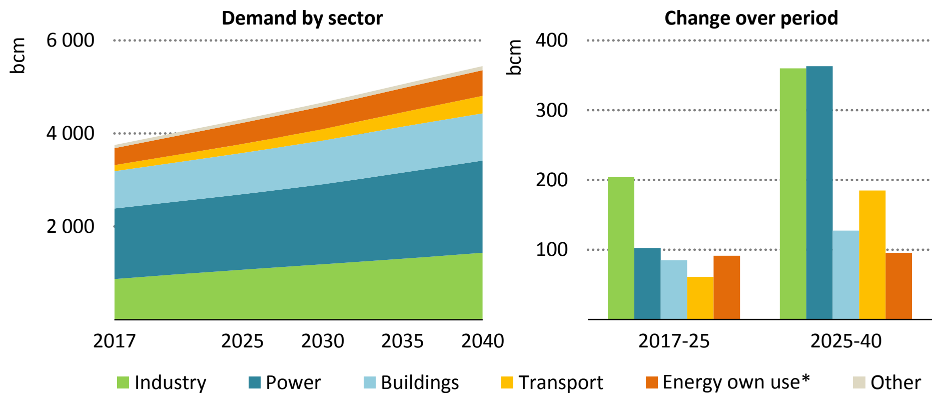
Gas continues to gain share in the energy mix in most regions, boosted by its versatility and environmental advantages

Unlike other fossil fuels, natural gas continues to make inroads in almost all **advanced economies**; the impacts of stagnant or declining primary energy demand are muted by the growing share of gas in the energy mix (Figure 4.4). In the United States, ample availability of gas at affordable prices fosters gas demand growth. In Korea, gas demand increases as the use of nuclear and coal in the power mix declines.

In 2017, over 60% of the global increase in gas demand was in the industry and buildings sectors. This is in contrast to the prevailing trend of the past where the power sector accounted for most of the increase in natural gas consumption (IEA, 2018a).

The **industry** sector is the main source of growth in natural gas demand in the New Policies Scenario, accounting for a third of the total (Figure 4.5). The chemical industry is the largest contributor: it uses gas to generate heat and steam as well as a feedstock to produce ammonia and methanol. Today gas is mainly used in energy-intensive industries that require high-temperature heat. In the New Policies Scenario, it is increasingly also used in light industries where there is strengthening policy impetus to curb emissions.

Figure 4.5 ▷ Global gas demand by sector in the New Policies Scenario



Industry remains the largest contributor to total gas demand growth, although the power sector contributes similarly in the latter part of the outlook period

* Includes energy used in oil and gas extraction, liquefaction, and refining processes.

The **power** sector is the second-largest contributor to increasing natural gas demand in the period to 2040. Prospects vary widely by region, but retirements of coal-fired capacity and strong demand for electricity create space for gas-fired power generation to expand in many developing economies in the latter part of the period. In some power systems, gas also has a role in providing flexibility to facilitate the deployment of variable renewable sources.

Outside China, there is only modest growth in demand for natural gas in the **buildings** sector in the New Policies Scenario. Gas use in this sector in advanced economies is curbed by increasing end-use efficiency and electrification, and – outside China – most developing economies do not have large seasonal heating needs.

Natural gas demand for **transport** nearly triples in the period to 2040, a result of policy-driven efforts to promote compressed natural gas (CNG) and LNG fuelled vehicles, especially in China. LNG use in shipping grows due to International Maritime Organization regulations to reduce the sulfur content in marine fuels, though its share in the overall fuel mix for shipping is modest (see Chapter 3).

4.3 Natural gas production in the New Policies Scenario

Table 4.3 ▷ Natural gas production by region in the New Policies Scenario (bcm)

	2000	2017	2025	2030	2035	2040	2017-2040 Change	2017-2040 CAAGR
North America	763	976	1 185	1 225	1 274	1 328	351	1.3%
Canada	182	184	181	173	175	194	10	0.2%
Mexico	37	32	33	38	50	60	28	2.8%
United States	544	760	971	1 014	1 049	1 074	314	1.5%
Central and South America	102	183	189	212	251	293	109	2.1%
Argentina	41	45	57	77	99	117	72	4.3%
Brazil	7	27	28	39	60	80	54	4.9%
Europe	338	291	227	207	205	203	-88	-1.6%
European Union	265	132	65	49	46	45	-87	-4.6%
Norway	53	128	128	109	107	105	-23	-0.9%
Africa	124	216	280	354	422	498	282	3.7%
Algeria	82	94	99	104	114	128	33	1.3%
Mozambique	0	5	15	42	55	69	64	12.2%
Nigeria	12	43	45	47	63	80	37	2.7%
Middle East	198	620	709	817	925	1 025	405	2.2%
Iran	59	214	241	275	302	315	101	1.7%
Qatar	25	169	188	219	244	264	95	2.0%
Saudi Arabia	38	94	106	121	139	157	63	2.3%
Eurasia	691	886	974	1 016	1 069	1 104	217	1.0%
Azerbaijan	6	18	32	39	44	46	28	4.1%
Russia	573	694	757	767	789	805	111	0.6%
Turkmenistan	47	80	90	114	136	154	74	2.9%
Asia Pacific	290	596	730	810	877	950	353	2.0%
Australia	33	105	158	178	191	208	103	3.0%
China	27	142	222	263	301	343	202	3.9%
India	28	32	41	58	71	85	53	4.4%
Indonesia	70	74	80	82	89	100	26	1.3%
Rest of Southeast Asia	89	151	152	155	154	146	-5	-0.1%
World	**2 507**	**3 769**	**4 293**	**4 641**	**5 025**	**5 399**	**1 630**	**1.6%**
Current Policies			4 386	4 860	5 366	5 847	2 078	1.9%
Sustainable Development			4 189	4 318	4 298	4 184	415	0.5%

Note: CAAGR = Compound average annual growth rate.

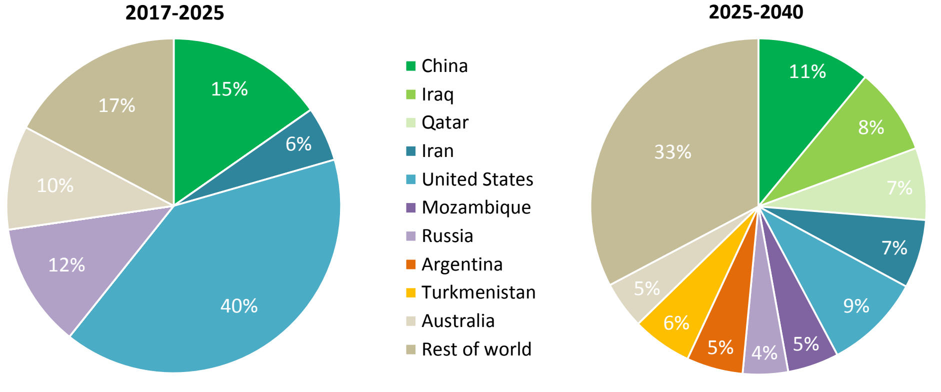
The natural gas supply projection in the New Policies Scenario is increasingly underpinned by unconventional gas production, which provides over half of the production growth in the period to 2040. Shale gas production expands by 770 bcm. The United States accounts for most of the growth to 2025, but other countries come into the picture thereafter, notably Canada, China and Argentina.

Conventional gas represents the majority of current gas production, but its share declines from 80% today to under 70% by 2040. Almost two thirds of production growth comes from the Middle East and Russia. Offshore production, deepwater in particular, accounts for an increasing share of conventional production, rising to almost half by 2040.

The share of associated gas in total gas output stays in a range between 10-15%. The United States remains the largest producer, although output begins to decline after US tight oil production reaches a plateau in the mid-2020s.

Today's major producers dominate production growth to 2025, with the United States taking the lion's share: five countries account for over 80% of total production growth. After 2025, there is a more diverse range of producer countries, with the top-five contributors accounting for less than 40% of the production growth (Figure 4.6).

Figure 4.6 ▷ Share by region in gas production growth in the New Policies Scenario



The supply picture becomes increasingly diverse after 2025; the top-ten contributors share around two-thirds of the production growth

The **United States** is the largest gas producer today and remains so throughout the outlook period. In the late 2020s, the country produces a third more gas than the next largest producer (Russia). Remaining resources of shale gas have been revised up to 34 tcm, a 5.5 tcm increase compared with our 2017 projection, in line with new estimates from the US Energy Information Administration: production in 2025 is now 70 bcm higher than in the *World Energy Outlook-2017 (WEO-2017)*. Today shale gas accounts for 63% of total US gas production; within five years this share reaches 80%. Shale gas production reaches its highest level in the early 2030s, and then declines slowly.

Shale gas production in **Canada** accelerates and by 2040 it accounts for around 70% of Canada's total gas production, compared with less than 5% today.

There have been promising signs from drilling activity in **Argentina**'s resource-rich Vaca Muerta Basin. Argentina also has a well-established gas market and improving conditions for investment. Today shale gas production is less than 3 bcm: after 2025, it expands by over 10% every year to more than 60 bcm in 2040, necessitating a search for new export outlets.

Natural gas production in **Russia** grows steadily through to 2040, maintaining its position as the world's second-largest gas producer. Today nearly all production in Russia comes from fields in Western Siberia and the Yamal peninsula, but the opening of new routes to China leads to production also expanding in Eastern Siberia and in Russia's Far East. Domestic consumption in Russia remains broadly flat, meaning that the rise in output has to find export markets.

Norway remains Europe's largest gas producer. Production is broadly constant until 2025 and then declines by around 1.5% per year due to waning North Sea production. In the **Netherlands**, the decision to restrict further gas production from the giant onshore Groningen field leads to a major decline in production. Groningen produces around 25 bcm today: this will be roughly halved in the next five years and reduced to zero by 2030. By 2040, production in the Netherlands falls to just under 10 bcm.

Natural gas production in **Iran** grew by almost 15 bcm in 2017, but the re-imposition of US sanctions has cast uncertainty over further substantive increases in the near term. The New Policies Scenario sees production expand to over 320 bcm after 2025, most of which is needed to meet growing domestic needs. Most of **Iraq**'s gas is associated with oil in its southern super-giant fields, although an estimated 18 bcm is currently flared. This situation changes in the New Policies Scenario as infrastructure is put in place, with the power sector the main beneficiary. The recent lifting of the moratorium on the North Field in **Qatar** will take some time to feed through into any substantial new gas volumes, and the New Policies Scenario sees production growth remain subdued until the mid-2020s. After 2025, production grows by nearly 80 bcm. The majority of this increase is exported as LNG.

Egypt is emerging as an important gas producer with development of its Zohr and Nooros gas fields and plans to evaluate the Noor gas fields. These lead to a jump in production of over 25 bcm by 2025. In **Mozambique**, the Coral floating LNG project was recently approved. While it does not make a material impact in the near term, production expands nearly fivefold after 2025 as onshore liquefaction plants are added.

China possesses vast shale and tight gas resources, but it faces substantial challenges in developing them, and the government's production projections have been consistently revised downwards. Substantial growth in demand acts as a stimulant to push shale gas production up by around 90 bcm between 2017 and 2040, along with other unconventional sources. China becomes the world's third-largest gas producer by 2040, surpassing Iran.

4.4 Trade and investment

Table 4.4 ▷ Natural gas trade by region in the New Policies Scenario

Net importer in 2040	Net imports (bcm)				As a share of demand			
	2000	2017	2025	2040	2000	2017	2025	2040
European Union	221	349	409	373	45%	73%	86%	89%
China	1	106	243	369	5%	43%	52%	52%
Other Asia Pacific	-65	-56	12	174	n.a.	n.a.	4%	36%
Japan and Korea	97	162	145	166	97%	98%	98%	99%
India	0	26	54	86	0%	45%	57%	50%
Rest of world	46	-27	-11	31	37%	n.a.	n.a.	16%
Net exporter in 2040	**Net exports (bcm)**				**As a share of production**			
	2000	**2017**	**2025**	**2040**	**2000**	**2017**	**2025**	**2040**
Russia	185	234	288	328	32%	34%	38%	41%
Middle East	24	119	148	224	12%	19%	21%	22%
North America	-37	7	106	154	n.a.	1%	9%	12%
Australia	10	60	107	149	31%	57%	68%	71%
Caspian	36	78	94	138	30%	40%	43%	46%
Sub-Saharan Africa	6	33	56	125	35%	51%	60%	53%
North Africa	62	37	48	63	58%	25%	26%	24%
Central and South America	5	9	5	19	5%	5%	3%	6%
World	**Trade (bcm)**				**As a share of production**			
	2000	**2017**	**2025**	**2040**	**2000**	**2017**	**2025**	**2040**
Pipeline	391	447	491	532	16%	16%	11%	10%
LNG	136	323	509	757	5%	5%	12%	14%
New Policies	**527**	**771**	**1 000**	**1 289**	**21%**	**20%**	**23%**	**24%**
Current Policies			1 019	1 464			23%	25%
Sustainable Development			985	1 080			24%	26%

Notes: n.a. = not applicable.

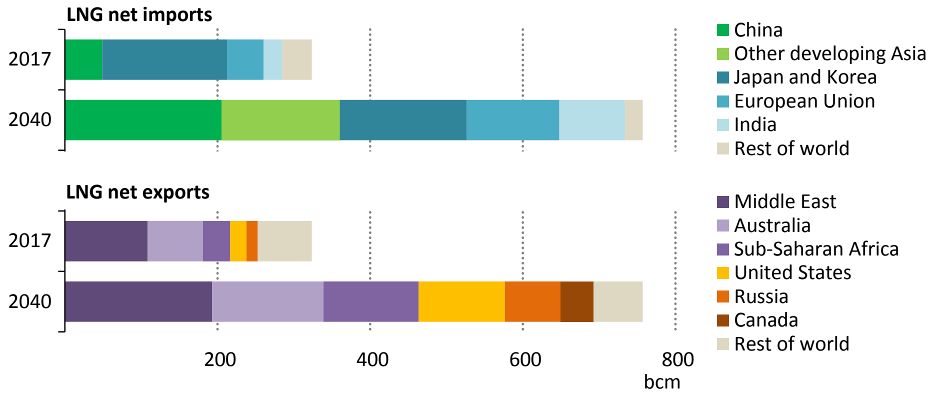
Global gas trade expands at an annual average rate of 2.3% over the course of the New Policies Scenario, much faster than the pace of demand growth (1.6% per year). This outlook underpins a major shift in the importer/exporter landscape. With rapidly increasing demand, China soon becomes the world's largest gas-importing country, and its net imports approach those of the European Union by 2040. With growing import needs in other Asian economies, over 60% of the world's gas trade finds a home in Asia. Russia and the Middle East remain the world's largest gas exporters throughout the outlook period, but their share in global exports gradually reduces with the rise of new exporters.

The growth in trade comes mainly from LNG, lifting its share in global gas trade from 42% today to almost 60% by 2040. Global LNG trade more than doubles to 760 bcm by 2040, making the gas market much more global and interconnected. China is the only region that shows a noticeable growth in trade via pipeline, mostly from Eurasia.

Asia is the primary destination for rising LNG imports. China and India account for over half of the growth in net LNG imports in the period to 2040. With waning production in Malaysia, Bangladesh and Pakistan, other developing countries in Asia increase their import volumes considerably. The Asia Pacific region accounts for around 80% of global LNG imports by 2040.

While the import picture concentrates on Asia, the export one becomes more diverse with a roster of new suppliers later in the outlook period. Today about 60% of LNG exports are from Qatar and Australia. Over the outlook period, first the United States and then sub-Saharan Africa each add some 90 bcm of export volumes and Russia increases LNG exports by 60 bcm. These three regions collectively take up larger stakes in global LNG exports, doubling their share from 23% today to over 40% by 2040 (Figure 4.7).

Figure 4.7 ▷ LNG net trade by region in the New Policies Scenario



Global LNG trade flows show contrasting trends; imports concentrate in Asia and export supply sources diversify

In the New Policies Scenario, around $380 billion of investment is needed each year for natural gas supply: upstream investment accounts for two-thirds, with unconventional plays taking an increasing share. The required investment for LNG infrastructure amounts to $35 billion per year on average. Since its peak in 2014-15, investment in LNG has declined to $20 billion in 2017 (IEA, 2018b). Although there are signs of a pick-up in new project approvals, the lack of final investment decisions in recent years still points to a possible risk of market tightening in the 2020s (IEA, 2018c).

Key themes

4.5 The future of gas demand in emerging Asian economies[1]

In the aftermath of the shale boom in the United States and the parallel LNG investment rush in Australia, there was a general expectation of structural oversupply in global gas markets that has not materialised at the anticipated scale. The rapid growth of gas demand in emerging Asian economies – led by China – has played a central role in challenging this expectation. Emerging Asian economies accounted for most of the increase in global LNG imports in recent years, with their share growing from 13% in 2010 to almost 30% in 2017. China and India accounted for the lion's share of this growth, but other countries were also substantial contributors. A number of countries, notably Indonesia, Malaysia and Pakistan, initiated LNG imports in recent years: Pakistan in particular emerged as the third-largest LNG importer among emerging Asian economies as it faced gas shortages. The share of emerging Asian economies in global LNG imports is set to grow further with additional countries – Bangladesh and potentially Myanmar, Viet Nam and the Philippines – joining the ranks of importers of LNG.

Where does gas demand in emerging Asian economies go from here? There appears to be plenty of room for further growth: the share of gas in the region's energy mix is less than 10%, considerably lower than the global average of 22%. Gas is also a good fit for a rapidly urbanising region with a population that is increasingly concerned about qualitative aspects of economic development, including air quality. However, the considerations vary widely by country:

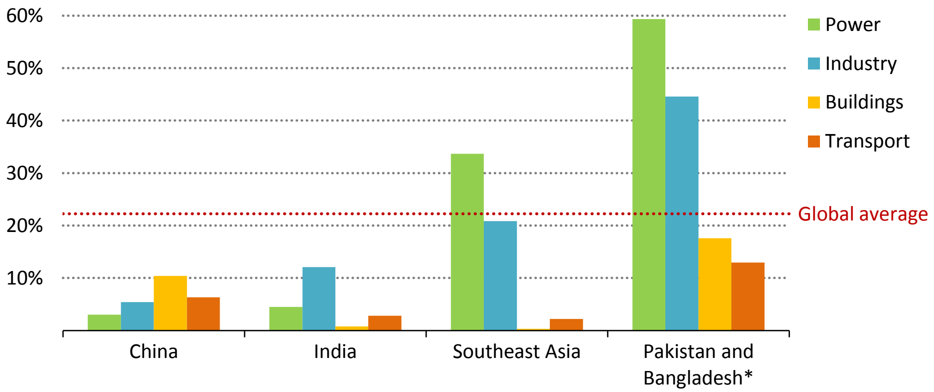
- The price of natural gas, of course, is a key variable and the structure of gas demand in each importing country affects the way in which it responds to changing market conditions. Price sensitivity varies by sector. Demand for gas for use in power generation can be more volatile; depending on relative prices and levels of variable renewable output, the role of gas can oscillate between baseload, mid-merit and peak load, leading to variations in consumption patterns. Demand from industry and transport is generally less sensitive to price, at least in the short term, as natural gas faces less immediate pressure from competing fuels and industrial processes may not be conducive to fuel switching. Natural gas demand in the buildings sector is also less sensitive to prices on an annual basis, but can show large swings in seasonal load.
- Policy measures to promote the use of gas (or to limit the use of competing fuels such as coal) can significantly influence demand levels. For example, in China the government is pushing coal-to-gas switching in industry and buildings to address environmental concerns. The introduction of similar policy measures in other Asian countries would translate into higher gas use; any retreat from policies favouring gas would have the opposite effect.

1. Emerging Asian economies include China, India, Southeast Asia, South Asia and other developing countries in the region.

- Security of supply is a concern. While some markets may have a basket of supply options that include indigenous production and imports via pipeline and LNG, others may rely solely on a limited number of supply sources. Confidence in the reliable operation of international gas markets is an important variable for the future.
- The availability of infrastructure is critical: in markets where gas networks are already well developed, there is an incentive to support their continued use as long as gas is reasonably reliable and affordable. The prospects for gas elsewhere are highly dependent on a readiness to expand gas networks.

Although the region is often dubbed "emerging Asia" as a whole, it is difficult to generalise about its gas demand. Gas has been a niche fuel in some markets (such as India) while it is well established in some others (parts of Southeast Asia, Pakistan and Bangladesh). Understanding the outlook for gas in emerging Asia requires a much more granular approach (Figure 4.8). It also requires a close look at the emerging gas giant – China.

Figure 4.8 ▷ Share of natural gas in the energy mix by sector in emerging Asian economies, 2017



Gas plays a different role and faces varying prospects in emerging Asian markets

* Shares in 2016.

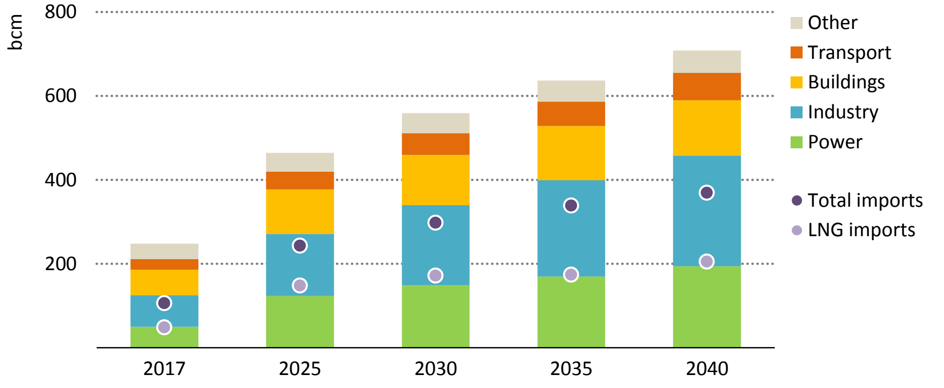
China shakes up global gas markets

Natural gas accounts for only around 7% of China's primary energy mix today, but demand expanded by a notable 16% in 2017 and the indications for 2018 look similarly strong. This is mainly attributable to the strong policy push for coal-to-gas switching in industry and buildings as part of the drive to "turn China's skies blue again" and improve air quality. In 2017, the government set targets for "clean" winter heating in Beijing, Tianjin and 26 other cities (the "2+26" cities) and announced a medium-term target for the whole of northern China to reach 70% of clean heating rates by 2021 (up from 34% in 2016).[2]

The continued push for clean heating is likely to have huge impacts on demand for gas and electricity. So far, coal-to-gas switching has been the main option to meet the target, but winter gas shortages in 2017 suggest that the future pathway is likely to be more diverse. While some regions continue to push coal-to-gas switching (e.g. the "2+26" cities), other regions may pursue electrification (or coal-to-electricity) or cleaner coal-burning technologies (coal-fired boilers retrofitted for low emissions), depending on resources and infrastructure availability. In the New Policies Scenario, we expect strong demand growth for both natural gas and electricity for heating at the expense of direct coal use, especially during the period to 2025.

Partly for this reason, and because of the broader shift towards a consumer oriented economy, electricity demand in China is set to increase by 30% in the years to 2025. Although growing electricity demand is primarily met by renewables and nuclear in our projections, there is scope for gas to contribute. China has also introduced incentives to use CNG for passenger vehicles and LNG for trucks. In the New Policies Scenario, gas makes strong inroads in every sector, taking total demand to 710 bcm by 2040 (three-times higher than today, and accounting for 14% of total energy demand in 2040) (Figure 4.9).

Figure 4.9 ▷ China's natural gas demand by sector and import needs in the New Policies Scenario

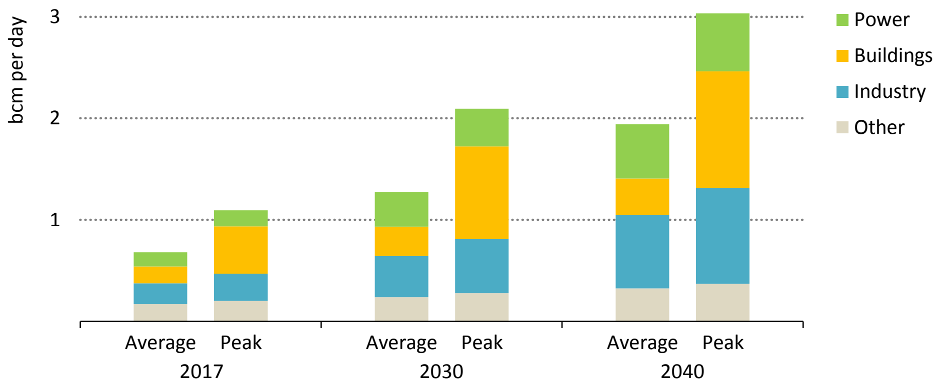


With rising gas demand in all end-use sectors, China's import needs more than triple in the period to 2040, and it becomes the world's largest gas-importing country

2. China's latest Clean Winter Heating Plan defines clean heating rates as the share of natural gas, electricity, geothermal, biomass, solar energy, industrial waste heat, nuclear energy and cleaner coal-burning technologies in total heating demand. In 2016, cleaner coal represented half of the clean heating demand in northern China.

By displacing more polluting fuels, rising gas demand helps to meet important Chinese policy objectives that target a high quality of development. However, it also brings challenges for security of supply as well as infrastructure development. Today, indigenous production meets around 60% of China's gas needs. In our projections, China's gas production increases by 4% per year (almost entirely driven by unconventional gas), but this is insufficient to satisfy soaring gas demand. Increasing volumes of imports are therefore required to fill the gap, especially via LNG. In the New Policies Scenario, China's needs for LNG more than quadruple in the period to 2040, becoming the largest LNG importing country in the world. Securing affordable and reliable gas supply, ensuring supplier diversification and building infrastructure in a timely way are becoming important challenges for Chinese policy makers.

Figure 4.10 ▷ Average and peak daily gas demand in China in the New Policies Scenario



China's peak daily gas demand is almost 60% higher than average daily demand

Infrastructure availability is a major potential constraint, and the recent winter gas shortage highlighted China's limited storage capacity. China's gas demand for buildings and power generation has a large seasonal swing, resulting in a large gap between average daily demand and peak day demand (Figure 4.10). China's current storage capacity, at around 12 bcm, can only cover around ten days of peak demand. In the New Policies Scenario, a significant expansion of storage capacity is required to balance the seasonality of demand. Pipeline capacity constraints and limited interconnectivity – the connection between existing trunk lines and pipelines and LNG import terminals – also hinder the expansion of gas, although small-scale LNG trucks are filling the gap to some extent. In recent years, the government has made serious efforts to expand gas storage and the pipeline network. In 2018, China's State Council issued an order to mandate gas suppliers, city gas distributors and local governments respectively to have storage capacity equal to 10% of supply, 5% of demand and three days of average daily demand by 2020, although there are challenges such as finding suitable sites for storage and addressing pricing issues.

Looking beyond China; Asia's other major gas markets

Although China is the largest, there are many other sizeable markets for gas across emerging Asia with huge room for growth. For instance, in **India**, the penetration of gas is low today (around 5% of the total energy mix), but this does not necessarily mean that it is poised to follow the path that China is taking.

The Indian government is keen to boost the use of gas to combat air pollution and is promoting the expansion of gas infrastructure: four additional LNG receiving terminals are under construction and a number of pipelines are being built to bring imported LNG to new consumers. The government has also made it a priority to expand city gas networks to stimulate demand in urban areas, alongside efforts to promote third-party access to infrastructure and liberalise the domestic gas market. The example of Gujarat state in the northwest shows what can be done: it has an extensive pipeline network and with only around 5% of the country's population, it accounts for almost one-third of national gas consumption. For the moment, though, Gujarat is an outlier. Elsewhere, particularly in states close to the main coal-producing areas, gas has struggled to gain ground.

Gas consumption in India's power sector (with less than a 5% share today) faces strong competition from coal and renewables, and the value of gas-fired plants as a source of peaking power is often not recognised or remunerated by cash-strapped electricity distribution companies. In the industrial sector, gas consumption today is concentrated in subsectors with potential for growth, notably the fertiliser, refinery and chemical industries. Gas might also be an economically attractive option for industries that use oil products for heat. However, the prospects for gas being used on a much larger scale as an industrial fuel depend on a helping hand from policy, without which it is likely to struggle to displace coal. Supportive policies can create an opening for gas as a residential fuel in some major urban areas, primarily for cooking, with the aim of freeing up liquefied petroleum gas (LPG) to replace solid biomass for use as a cleaner fuel outside the cities. Yet the absence of major heating requirements in India limits the potential for gas use in the buildings sector.

The result in our New Policies Scenario is steady, rather than spectacular, growth in gas use in India, with an expansion of around 5% per year bringing consumption to 170 bcm by 2040, mostly driven by the power and industry sectors. LNG imports take most of the strain on the supply side, reflecting slower domestic production growth and the limited scope for pipeline imports (for the moment, we do not see the proposed Turkmenistan-Afghanistan-Pakistan-India pipeline coming to fruition).

Infrastructure will be a crucial determinant of the future role of gas in India. If there is sufficient confidence in the LNG market, one approach to gas market development could be to focus infrastructure development on specific areas near the coast, where there is easy access for LNG and a relatively dense concentration of urban and industrial users.[3] Gas-fired power could then be made more widely available via the electricity grid (the so-called "gas-by-wire" model) if distance, cost and planning issues mitigate against the extension of gas pipeline networks.

Price reforms are also crucial for gas to expand its role in India. Regulated prices for domestic gas are dampening investment in upstream activities while creating distortions in consumption patterns. Sectors with priority access to domestic gas may not be incentivised to use it as efficiently as possible, meaning that other sectors without priority access have to pay more for their gas than they otherwise would, which undermines the potential for demand growth (Boersma, Losz and Ummat, 2017). Several steps have been taken to improve gas pricing in recent years and the direction and pace of further reforms is likely to have a significant impact on the outlook for natural gas.

At the other end of the spectrum from China and India, there are markets in Southeast and South Asia where natural gas already occupies a much higher share in the energy mix. In **Southeast Asia**, a number of countries are highly dependent on gas for electricity: today around one-third of the region's power is generated by gas, and this share is 53% in Thailand and over 90% in Singapore. The question in Southeast Asia is therefore quite different from that in China and India: can gas retain its current position in the mix?

It will be challenging. In many parts of Southeast Asia, domestic gas production is failing to keep pace with demand, leading to a rise in imported gas. In these circumstances, countries may turn to readily available alternatives to gas in order to meet surging electricity demand. In the New Policies Scenario, gas use for power increases in absolute terms but loses share to renewables and coal in the overall mix. The largest growth of gas demand instead comes from industry, as the region adds a host of manufacturing facilities. Gas has fewer opportunities to penetrate into the buildings sector given scattered demand centres, low levels of demand for heating and the absence of distribution networks.

Although Southeast Asia contains major current LNG exporters like Malaysia, Indonesia and Brunei Darussalam, the New Policies Scenario sees the region becoming increasingly dependent on LNG imports over the period to 2040. The rise of 90 bcm in LNG imports is much higher than the growth in India over the same period. Security of supply is therefore a critical variable in shaping the prospects for gas in this region. If policy makers perceive future supplies as secure, gas is set to sustain a large share in the energy mix, but frequent price spikes or perceived security of supply risks could change the picture.

The outlook in parts of **South Asia**, notably in Pakistan and Bangladesh, is different again. The energy mix in both of these countries is highly reliant on gas; growth in indigenous production has helped to push the share of gas in the energy mix up to over 25% in

3. Natural gas compares favourably to other energy carriers as a clean urban energy solution when demand is reasonably concentrated and the region's power system depends on emissions-intensive fuels such as coal. With higher conversion efficiencies, gas boilers require less primary energy to produce heat, thereby incurring less carbon and air pollutant emissions.

Pakistan and almost 60% in Bangladesh. Gas use is highest in the power sector, but (in contrast to Southeast Asia) is also prominent across all end-use sectors. Here too, more limited availability of domestic gas is putting pressure on the system: subdued production in recent years has caused severe gas shortages, which have triggered fuel switching in an unconventional direction, from gas-to-coal and even to oil, alongside the initiation of LNG imports. As in Southeast Asia, confidence in the reliability and affordability of supply will be important in shaping the future prospects of gas. While domestic infrastructure favours continued use of gas, there is an emerging need for additional imports to feed the existing network. In our projections, these supplies arrive in the form of LNG, although an alternative possibility for Pakistan in particular is to source pipeline imports from Iran or from Turkmenistan (both of these routes face sizeable political obstacles, at least in the near term). If either of these projects were to be realised, they would anchor a significant part of Pakistan's gas demand.[4]

Countries in South Asia pursue a diverse set of power generation options in the New Policies Scenario, gradually reducing the share of gas in the power mix and increasing the share of renewables and coal (and nuclear in Pakistan). However, there are still opportunities for gas to displace fuel oil and diesel in the power mix and to meet increasing electricity demand: these put gas demand for power generation on a moderately rising trajectory through to 2040. Gas also continues to make inroads into the expanding industry sector and demand also grows in buildings: unlike in India and Southeast Asia, there is demand for winter heating in parts of Pakistan.

Implications for global LNG markets

In the New Policies Scenario, gas faces varying prospects in each of the emerging Asian economies. Gas makes a rapid transition from a niche fuel to a mainstream fuel in certain markets, while in others it faces intense competition to defend its prime position. Nevertheless, a common feature is their growing need for LNG imports. Emerging Asian economies account for over 80% of the growth in global LNG imports in the period to 2040, and their share in LNG imports more than doubles from less than 30% to 60% in 2040.

The consumers driving the increase of LNG imports have differing demand profiles, which means that their interactions with global LNG markets may vary substantially. To give a sense of these variations, we consider this import demand in three indicative categories.

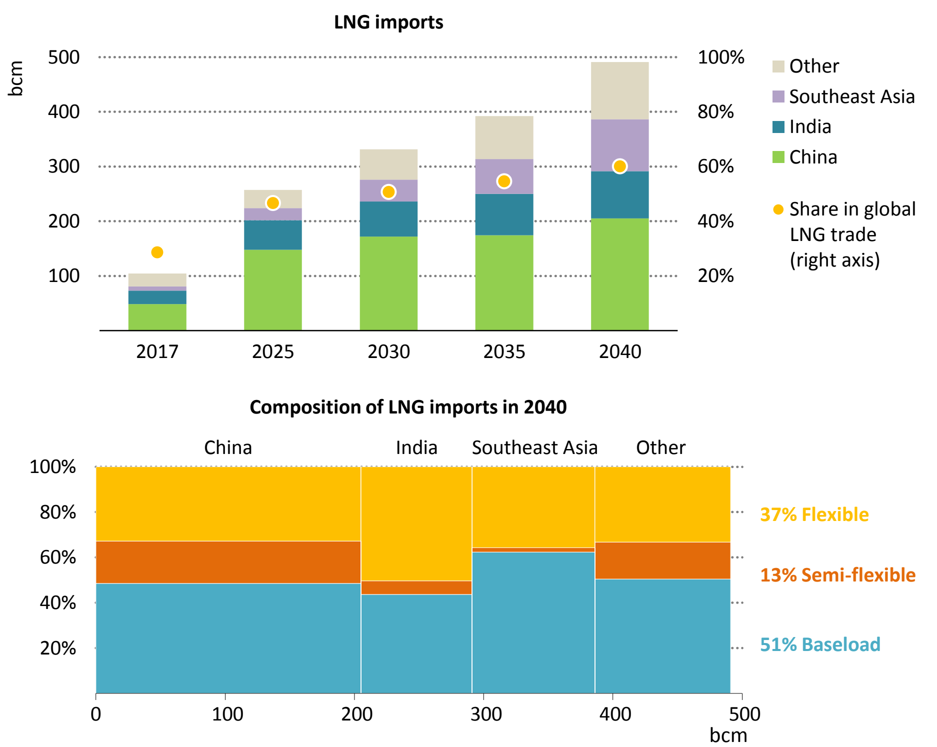
- "Baseload" LNG imports: these include natural gas demand in industry, particularly the energy-intensive segments, and transport which tends to be relatively constant throughout the year. In addition, where gas provides baseload power generation or there is not much excess capacity in the market, demand for gas in power generation could also be well suited to regular shipments of imported gas.

4. For example, the proposed Turkmenistan-Afghanistan-Pakistan-India pipeline has planned total capacity of 33 bcm/year, of which 14 bcm/year is for Pakistan. This volume corresponds to over 40% of today's gas demand in Pakistan.

- "Semi-flexible" LNG imports: include demand in the buildings sector, which can have significant seasonal load variations. When there is insufficient storage capacity to balance seasonality (as in most emerging Asian countries), LNG is an option for dealing with seasonal demand variation, providing flexibility to ramp up and down as needed.
- "Flexible" LNG imports: demand in power generation (especially peak or mid-load demand) is likely to depend on price competition with other available fuels on an annual basis as well as over the long term. This segment is more opportunistic and is likely to value contractual terms that offer flexibility and have shorter duration.

In the New Policies Scenario, the largest increment in LNG consumption between today and 2040 comes from the baseload segment, underpinned by demand growth in industry: this is the largest source of demand growth in all major countries except for India. The baseload segment represents around half of total LNG demand in 2040 (Figure 4.11).

Figure 4.11 ▷ LNG imports in emerging Asian economies in the New Policies Scenario



Emerging Asian economies become heavyweights in global LNG markets, with their share of global LNG trade more than doubling to 60% by 2040

The importance of the baseload segment suggests that Asian importers could provide the sort of longer term offtake commitments that might underpin new upstream and infrastructure developments elsewhere in the world. At the same time, the more price-sensitive flexible segments that may vary their purchases depending on the price of gas, stand to benefit from movement towards a more liquid and competitive LNG market. Aggregators (or "portfolio players") that can provide shorter term volumes on demand promise to be an important source of gas for these more opportunistic consumers.

The way that this market evolves will have implications far beyond Asia. A more flexible LNG market, combined with a price-responsive segment of gas demand in Asia's power sector that can switch away from gas if prices rise too high, would be an important contributor to overall gas security. Such a market could potentially serve as a buffer to absorb any supply or demand shocks to the system, compensating for a loss of flexibility in Europe and the United States as coal-fired capacity falls and reduces fuel-switching capabilities in these regions. This though would depend critically on the progress made in developing well-functioning gas and electricity markets in Asia that allow price signals in international markets to feed into decisions throughout the value chain.

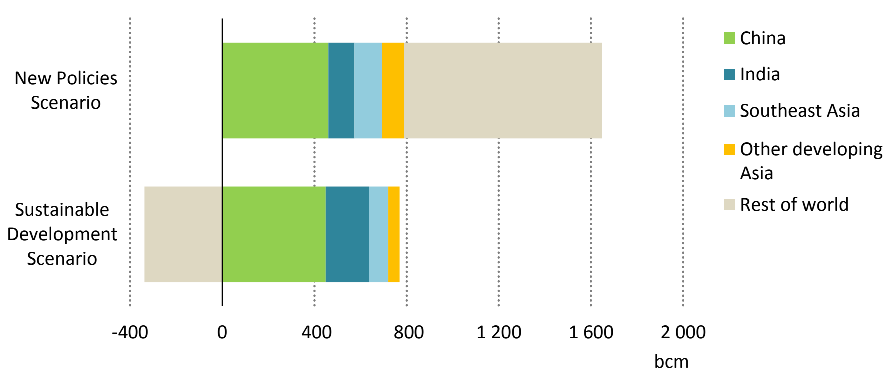
To the extent that policy makers in Asia feel that gas represents a reliable, affordable option that helps to meet their economic and environmental objectives, they will be ready to commit to the policies and the infrastructure necessary for its growth – as China is demonstrating. For exporters and suppliers, this creates an imperative to keep the cost gap with competing fuels as narrow as possible and to develop commercial strategies that are adapted to the demands of Asia's new consumers (see section 4.6). The development of a liquid and competitive LNG market is therefore closely linked with the prospects of gas demand in emerging Asian economies and vice versa.

Box 4.1 ▷ Emerging Asian gas demand in the Sustainable Development Scenario

Gas demand grows in most parts of the world in the New Policies Scenario, but there are strong regional variations in the Sustainable Development Scenario. While gas use comes under pressure from the expansion of renewables and from strong energy efficiency policies in many advanced economies, emerging Asia remains a key source of demand growth to 2040 as gas plays a prominent role – alongside renewables – in displacing more carbon-intensive fuels. In the Sustainable Development Scenario, the share of gas in the energy mix rises to almost 20% in China and 16% in India by 2040, compared with 14% and 8% in the New Policies Scenario. Gas demand also grows in Southeast and South Asia, but less robustly, reflecting its already strong position in the energy mix.

There is a striking similarity in outcomes (in volume terms) for natural gas between the New Policies Scenario and the Sustainable Development Scenario in emerging Asian economies (Figure 4.12). However, this does not mean that a positive role for gas in the region can be taken for granted. If the price, policy, security of supply and infrastructure issues are not overcome, most of the alternative pathways would involve greater reliance on a combination of indigenous renewables and coal, the latter coming with a range of local and global environmental hazards.

Figure 4.12 ▷ Changes in gas demand by region and scenario, 2017-2040



Owing to China and India, growth in emerging Asian gas demand in the Sustainable Development Scenario is largely the same as the New Policies Scenario

4.6 Exporter strategies in a changing gas market order

Global gas markets, business models and pricing arrangements are all in a state of flux. Thus far, increasing LNG supply is being absorbed by robust demand, particularly in Asia. However, an additional 100 bcm of liquefaction capacity is expected to come online by 2023, as the expansion of export capacity continues in Australia and the United States. With a host of new players positioning themselves between buyers and sellers, the market itself is becoming more contestable, with signs of more flexibility in contractual provisions on destination and re-sale, more gas-on-gas competition and a greater share of gas being sold on a spot or short-term basis. However, it is not clear that buyers' expectations of new, more flexible contractual terms are a good match for what sellers will need to underpin major new infrastructure projects, which continue to require long-term commitments. In this section, we examine the implications of changes in the market for suppliers, consumers, and for business models and investment.

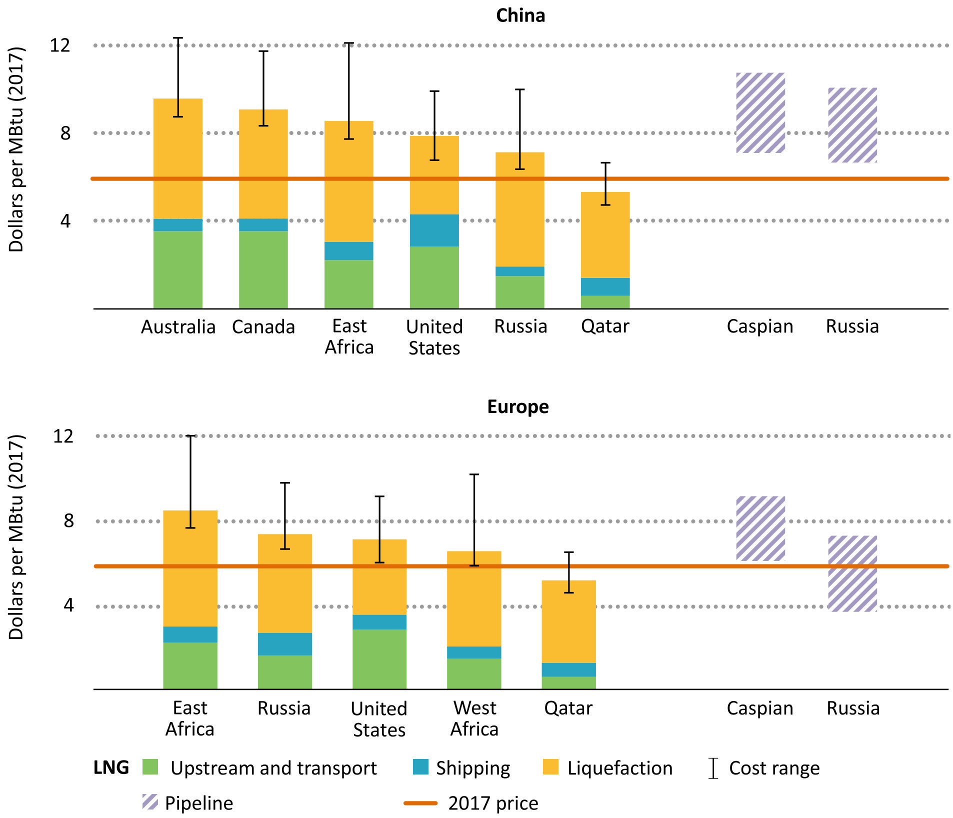
Qatar's plans to expand its LNG capacity are an important test of market sentiment. With a geographical position ideally situated to serve both Asian and European markets, Qatar is in a strong position to develop a sizeable part of new LNG liquefaction projects scheduled to come on stream in the mid-2020s. Its potential to tap into liquids-rich gas and leverage its vast existing infrastructure complex at Ras Laffan means that it sits firmly at the bottom of the cost curve for new supply. Following the lifting of a self-imposed moratorium on further development of the vast North Field, Qatargas announced its intention to add around 45 bcm to its supply portfolio by constructing four new liquefaction trains. The eventual pricing and contracting structures underpinning these future volumes will give some indication of whether traditional exporters are willing to countenance changes to the way the market works. The early indications are that there is still an appetite for longer term arrangements: ten years after its last contracts with Chinese buyers, Qatargas recently announced a new 22-year oil-linked contract with PetroChina, which would follow a 15-year contract signed in 2017 by Qatargas with Bangladesh (IEA, 2018c).

Many other countries are looking to expand or announce their presence in international gas markets. The commissioning of Yamal LNG in Russia on time and on budget in 2017 – against market expectations – has reignited discussions about future prospects in the Arctic, and the Russian government's exemption of Yamal LNG from mineral extraction and export taxes may provide the template for further projects. Mozambique has long been exporting gas via pipeline to South Africa, but its horizons expanded with major discoveries in the offshore Rovuma Basin: the Coral floating LNG project was approved in 2017, and there is now the prospect of larger onshore liquefaction investment to develop these resources at scale. The decision in October 2018 to move ahead with the LNG Canada project in British Columbia is Canada's first large-scale move into LNG, allowing the country to look beyond its regional role as a pipeline supplier to the United States. In West Africa, the gas discovered on the maritime border between Mauritania and Senegal looks destined for export. Although Argentina has no current plans for LNG, it too may well be drawn towards this market as and when it needs to find outlets for expanding production from the Vaca Muerta play.

The likelihood of a second wave of LNG investment in the United States looms large in the investment calculations facing projects elsewhere in the world. New US LNG projects are not the least expensive option for incremental gas delivery into either European or Asian markets; it is highly unlikely that any project will be able to undercut Qatar on this score (Figure 4.13). However the size of US resources, the large number of proposed LNG export projects, the scope for production flexibility, together with an LNG export industry actively seeking arbitrage opportunities, combine to put a ceiling price in the market – a deterrent for any project that requires a gas price higher than the delivered cost of US supply.

The long shadow of US LNG adds to the complexity facing other projects as potential sellers try to align their interests with those of potential buyers. There is, for the moment, little consensus on the appropriate choice of pricing mechanisms, contract durations and degree of flexibility, or on whether the world is still in a buyers' market or is seeing bargaining power gradually shifting back towards sellers. In addition, LNG projects in different parts of the world all carry their own unique challenges. The recently approved LNG Canada project, for example, will require 670 kilometres of new pipeline infrastructure to transport gas to the LNG facility on the coast. In sub-Saharan Africa, the lack of a developed governance framework and undercapitalised market players could lead to delays and financing problems (the latter having already affected Fortuna LNG's deepwater project in Equatorial Guinea).

Figure 4.13 ▷ **Indicative delivered cost of selected new gas supplies to China and Europe in the New Policies Scenario, 2025**



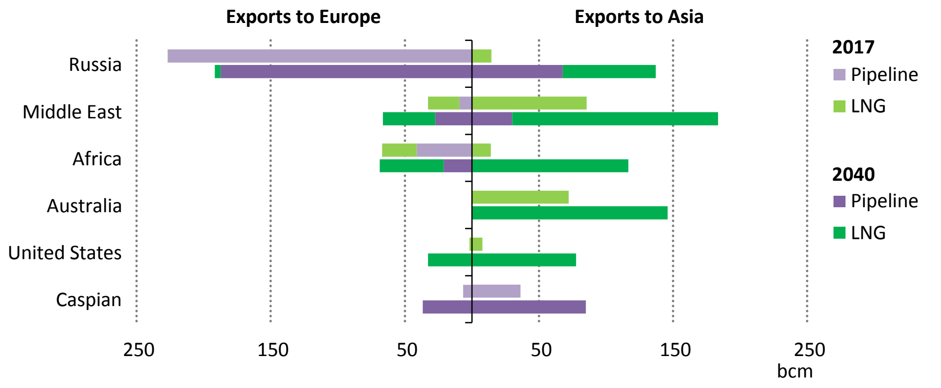
There are up to 1 300 bcm/y of potential new gas export projects; managing costs and securing financing without committed buyers is key to future capacity

Notes: Upstream and transport includes the cost of new infrastructure to deliver feedgas to a LNG plant. Shipping excludes the cost of regasification. LNG cost stacks are indicative benchmarks using generic capital and operating cost assumptions, while the ranges reflect the project- and location-specific uncertainties related to upstream finding and developing, liquefaction and pipeline costs.

For pipeline exporters, which are even more reliant on minimum capacities and firm delivery commitments to justify the considerable upfront costs of construction, the new gas order may create an enduring disadvantage relative to LNG. The Caspian region is emblematic of the current strategic dilemma for landlocked gas exporters. For Turkmenistan, for example, potential export markets are limited by its geographical position between Russia and Iran, both of which are themselves large gas producers and therefore have few incentives to provide transit. Partnership with China has enabled the financing and construction of the first three lines of the 55 bcm/y Turkmenistan-China Gas Pipeline, but reaching other large gas-consuming markets is proving challenging. The most advanced of the current diversification projects is the 33 bcm/y Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline, but its viability is compromised by transit risk through Taliban-held areas of Afghanistan, as well as by Pakistan and India's access to LNG.

In Russia, the vast majority of exports take the form of pipeline supply to Europe, where long-term demand reduction is partially offset by declines in indigenous production (see section 4.7). Russia therefore continues to pursue further large-scale pipeline projects into Europe such as the 55 bcm/y Nord Stream II project and the two-string Turkstream link through the Black Sea (each with a capacity of 15.75 bcm/y). The Power of Siberia opens up a direct route to China, with the possibility of further expansion linked to China's import needs. However, it may become increasingly difficult for a rigid pipeline gas strategy based on exclusive rights for Gazprom to coexist with flexible LNG supplies marketed by competing Russian players. LNG could therefore gradually force changes in Russia's overall approach to gas export.

Figure 4.14 ▷ Selected LNG and pipeline gas exports to Europe and Asia in the New Policies Scenario



Most of the additional growth in gas trade to 2040 is to satisfy demand in Asia

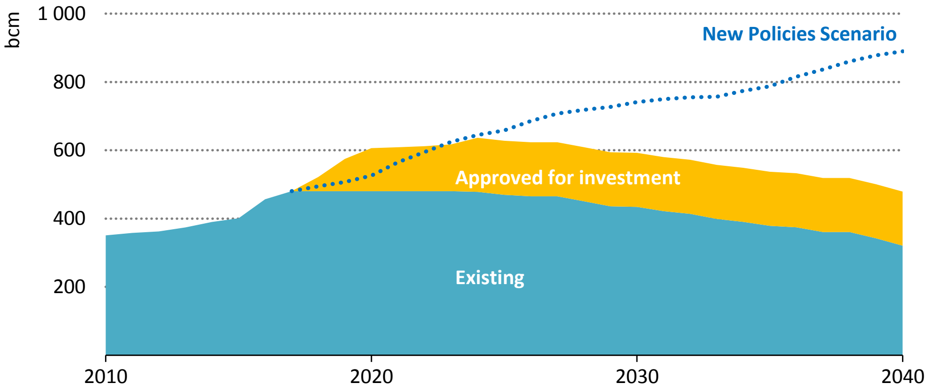
In this *Outlook*, Russia and the Middle East – led by Qatar – retain their position as the top-two net exporters of gas, with a combined market share of 43% of total global gas trade by 2040. However, the overall picture is one of increased diversity and competition. In a globalising LNG market where destination-flexible US volumes provide an upper bound on price in each region, competing exporters sell into markets where they have a competitive geographical advantage. The Middle East, Russia and East Africa in particular benefit from favourable access to the two key importing regions of Europe and Asia; Australian and US LNG exports gravitate towards Asia (Figure 4.14).

Buyers and sellers – never the twain shall meet?

The pickup in new LNG project approvals in the second half of 2018 suggests that the risk of an abrupt tightening in gas markets around the mid-2020s may be easing, although a steady flow of additional projects would still be required to meet demand in the New Policies Scenario (Figure 4.15).

However, there is still considerable uncertainty about what kind of business models and contracting structures will underpin new investment decisions. Projects that can come to market relatively quickly and at relatively low cost are the ones most amenable to the industry's current focus on capital discipline and short-cycle investments. This works in favour of established low-cost exporters such as Qatar. It is likely to work in favour of brownfield projects elsewhere, notably in the United States, where there is already a queue of new projects and expansions with regulatory approvals that are waiting for the right market conditions to move ahead. However, our analysis suggests that large-scale greenfield projects can also find a place in the new gas order. The creditworthiness and risk-sharing arrangements among the players involved in a given project can overcome uncertainty about future market conditions and the need for bankable guarantees for capital-intensive gas supply projects.

Figure 4.15 ▷ Global liquefaction capacity, existing and approved, compared with requirements in the New Policies Scenario



Recent project approvals have narrowed the gap between expected liquefaction capacity and projected demand in 2025

With growth in flexible and spot volumes and the increasing diversity of global LNG supplies, new market players are emerging and starting to challenge the traditional bilateral relationship between buyers and sellers that has underpinned investment in new capacity. Various utilities, national and international oil companies, independent developers and trading houses are increasingly seeking to manage risk or create value from greater optimisation and trading.

The result is an increasingly blurred distinction between buyers and sellers. Larger portfolio players (also known as aggregators) contract capacity at liquefaction and regasification terminals around the world (paying for the upfront fixed costs of doing so) without a specific destination for these volumes. Smaller independents and trading houses take open positions in the market, buying and selling single cargoes to take advantage of arbitrage opportunities. European and Asian utilities have meanwhile developed their own trading capabilities, evolving away from their traditional role as passive off-takers. Their increased ability to access both short- and long-term contract gas in a flexible way widens the opportunities for arbitrage, with the growing spot market providing a handy backstop for contract surpluses. Some have entered into joint venture partnerships with one another for this purpose, such as the recent agreement between EDF, a French utility, and JERA, a LNG buyer in Japan, created from a merger of long-term contracts of Chubu and Tepco, both Japanese electric utilities. The expanding middle ground has helped to underpin the growth of spot LNG sales, allowing for the re-selling, swapping or redirecting of cargoes, utilising a wide variety of short- and long-term contracts.

While this has helped accommodate buyer preferences for greater flexibility around existing supplies, several new projects continue to require long-term commitments to secure the funding necessary to build new liquefaction projects. This is where the mismatch between buyers and sellers is most pronounced.

New solutions for this impasse are beginning to emerge. By leveraging their supply chain presence, large creditworthy portfolio players such as integrated oil and gas majors can underpin new supply capacity on the strength of their balance sheets without necessarily locking in significant long-term volume commitments from buyers. These companies can then break up their contracted output from large-scale projects to match the volume, tenure and flexibility requirements of smaller buyers across multiple markets. Their investment decisions may be driven not just by the stand-alone economics of single projects but also by the value that a project might add to an integrated portfolio of assets (for example by opening up optionality and hedging opportunities). For players with less easy access to credit, LNG developers in the United States are offering prospective buyers equity stakes in new liquefaction terminals in exchange for bearing some of the market risk associated with the commissioning of new capacity. Mid-sized independent players are also experimenting with multiple small-volume, short-term contracts with buyers of various credit ratings, which together can attract enough financing for a larger project, while mid-stream players are adding power generation capabilities to floating storage and regasification units, tempting buyers to sign up to integrated, "plug-and-play" options to use LNG for electricity.

In aggregate, these multiple strategies, which in various ways leverage the expanding middle ground and the opportunities to spread market risks more evenly along the value chain, offer scope to ensure the health of the global gas balance. The final investment decision for LNG Canada in late 2018 is a case in point: a joint venture partnership between Shell, Petronas, PetroChina, Mitsubishi and Kogas, the project is not backed by any long-term contracts. Rather, its partners are responsible for their own gas supply and marketing strategies, implying a greater spread of risk among a diversified, creditworthy ownership pool. Strong government support has also been essential to overcome exceptionally complex land use, regulatory and social issues.

The changes that are taking place should not, however, lead to the conclusion that the old order has ceased to exist, or that every buyer is looking to maximise the flexibility of their contracts. Some buyers, especially in large growth markets such as China, remain keen on firm delivery. Volume flexibility may be useful in an oversupplied market, but the value of firm, guaranteed deliveries will go up if the balance tightens. Market players who have a portion of their supply locked-in with long-term contracts would stand to benefit in such an environment, while buyers relying primarily on short-term contracts would find themselves exposed to price floors set by the relative willingness of competing regions to pay for gas. A buyer's import portfolio is therefore likely to feature a balance of firm, flexible and uncontracted gas in order to match the price and volume sensitivity of their demand profile.

4.7 Natural gas in Europe's Energy Union

Gas is a major element in the European Union's energy mix, and is particularly important for the provision of power and heat to both buildings and industrial processes. Over at least the next decade, many of the European Union's climate and environmental policies provide important indirect support for gas: for example, reforms to the emissions trading scheme, which will become operational in 2019, have the potential to increase the price of carbon emissions, thereby further encouraging fuel switching from coal-to-gas. Other EU policies encourage more gas infrastructure to support competition and security of supply, thus reinforcing the use of gas. In the long term, however, the prospects for gas are less certain in the face of EU policies that support energy efficiency and renewable energy.

The European Union is currently the world's largest importer of natural gas, and continued declines in domestic production mean that reliance on imports is set to increase. The evolution of Europe's gas infrastructure and the operation of its internal gas market have a strong bearing on how these import needs are going to be met, and its implications for the security and diversity of gas supplies. Although there are many moving parts, much of this boils down to a battle for market share between Europe's largest gas supplier, Russia, which is currently setting records for pipeline gas exports to Europe, and the rising international supply of LNG.

The EU's Energy Union Strategy[5] depicts a long-term vision for a more secure, sustainable, competitive EU energy market, one in which gas can flow freely across borders and

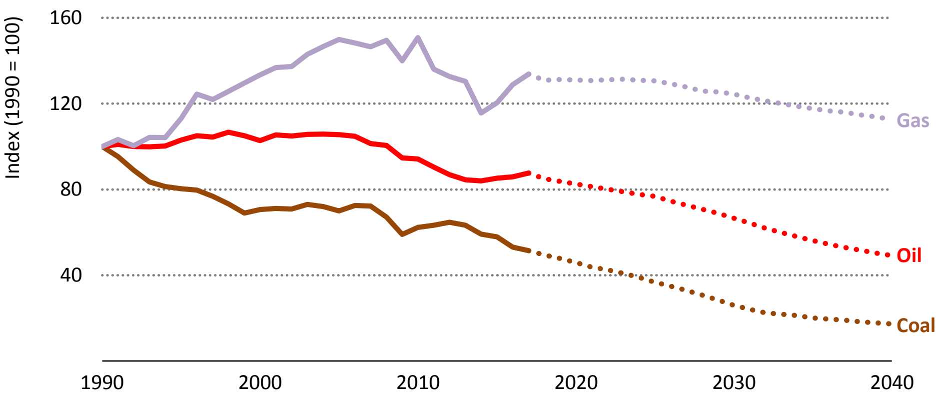
5. A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, presented in 2015. Our projections for the European Union are for its composition as of 2018, i.e. including the United Kingdom.

member states have access to a diversified portfolio of supply options. This builds on the achievements of the Third Energy Package agreed in 2009, which has sought to remove physical and regulatory barriers to a fully functioning internal market. We analyse gas demand, supply and infrastructure in the European Union in this context, employing our scenario projections and a new model of the EU's gas infrastructure to investigate how the EU's policy choices, as it strives for an "Energy Union", might shape the outlook.

Demand – is gas running out of steam in Europe?

There is considerable uncertainty about future gas demand in the European Union. After reaching a peak in 2010 of 545 bcm, gas demand declined for four consecutive years, mainly as a result of falling electricity demand and of competition from renewables and lower cost coal. However, since 2014, lower gas prices have underpinned a partial reversal of fortune in power generation, and the EU's gas consumption has grown by 4-7% per year.

Figure 4.16 ▷ Demand for gas, oil and coal in the European Union in the New Policies Scenario



Gas demand grew substantially in the 1990s and 2000s. As a cleaner burning fossil fuel, its prospects in a decarbonising European energy system are better than those of oil and coal.

In 2018, the European Union reached a political agreement on new, binding renewable energy and efficiency targets: the agreement stipulates a 32.5% increase in energy efficiency across the European Union and a 32% share of renewable energy by 2030. These revised targets have the potential to affect the outlook for gas demand in the European Union, although the effects will not be uniform because the profile and role of gas varies widely across European countries (Box 4.2); moreover, the effects are unlikely to be felt until later in the outlook period. For the next decade, at least, the prospects for gas demand in the European Union look relatively upbeat, compared with other fossil fuels (Figure 4.16).

Box 4.2 ▷ Europe's diversity of gas consumers

The role of gas varies widely across the countries of today's European Union. The six largest consumers of gas are responsible for 75% of total EU demand for natural gas (although in the New Policies Scenario, this share declines to two-thirds). Gas plays a particularly important role in the energy mix of Italy, the Netherlands and the United Kingdom, whereas in other countries, such as Sweden and Finland, the gas share is well below 10% (Table 4.5). Gas is an important fuel for industry in most EU countries, but its role for heating buildings and for power generation varies significantly from country to country. As examined in more detail in the following section, the various consumption patterns in different countries have implications for the utilisation of gas infrastructure: sectors are subject to varying policy pressures and they have varying seasonal characteristics, meaning that they contribute differently to the periods of peak load on the system.

Table 4.5 ▷ Share of gas in overall energy demand by country in the European Union (averages for 2010-2016)

Size of market	Country	Share of gas in TPED	Share of gas in sectoral demand		
			Power	Industry	Buildings
>20 bcm	Germany	20%	13%	35%	35%
	United Kingdom	31%	31%	33%	57%
	Italy	32%	41%	33%	50%
	France	12%	4%	37%	30%
	Netherlands	38%	48%	35%	64%
	Spain	18%	20%	40%	21%
10-20 bcm	Belgium	24%	22%	35%	40%
	Poland	11%	3%	23%	18%
	Romania	25%	20%	40%	33%
5-10 bcm	Hungary	29%	24%	32%	48%
	Austria	19%	21%	34%	19%
	Czech Republic	14%	5%	30%	31%
	Slovak Republic	23%	11%	26%	48%
<5 bcm	Ireland	26%	51%	28%	25%
	Portugal	15%	27%	23%	10%
	Greece	11%	17%	16%	7%
	Denmark	13%	16%	30%	13%
	Bulgaria	11%	8%	31%	4%
	Finland	6%	10%	6%	1%
	Lithuania	31%	58%	31%	10%
	Croatia	22%	29%	34%	20%
	Latvia	22%	58%	20%	11%
	Sweden	2%	1%	3%	1%
	Luxembourg	22%	82%	42%	37%
	Slovenia	9%	4%	34%	9%
	Estonia	7%	7%	20%	8%

Notes: TPED = total primary energy demand. Cyprus and Malta excluded.

The resilience of gas in the **power sector** is primarily a result of the closure of 50% of coal-fired capacity by 2030, and of reductions in nuclear power in European Union member countries. Installed gas capacity in the European Union increases by some 70 gigawatts (GW) to reach over 280 GW by 2040. Despite these capacity additions, gas consumption in power plants declines by 0.5% per year to 2040. With renewables-based capacity set to almost double by 2040, the business case for building new gas-fired power plants in Europe relies less on high load factors and more on the value attached to the firm capacity that gas can provide to electricity systems with high shares of variable renewable sources (see Chapter 10, section 10.4).

Buildings are the single largest consumers of gas in Europe, accounting for 38% of the EU's gas consumption in 2017 (Table 4.6). In our projections, gas demand in this sector declines by an average of 1.2% per year. Overall floor space in most countries increases, and gas benefits from fuel switching in some countries that still have a large number of oil-fired boilers. However, new policies are set to push up the efficiency of the buildings stock, plus new condensing boilers lead to higher efficiency gains. There is also an increase in the use of electricity in buildings, spurred by increased investment in electric heat pumps. These effects vary by region: northwest Europe sees a significant decrease in gas use in buildings, while in central and eastern Europe this drop is not as pronounced, as efficiency gains are offset by increased demand from the growth in floor space.

Table 4.6 ▷ Natural gas demand in the European Union in the New Policies Scenario (bcm)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
Power generation	127	151	153	147	138	135	-16	-0.5%
Buildings	183	185	176	165	153	140	-45	-1.2%
Industry	145	116	114	109	104	101	-14	-0.6%
Transport	1	4	5	6	8	10	6	3.9%
Other	31	26	24	23	22	22	-4	-0.8%
Total	**487**	**482**	**472**	**450**	**426**	**408**	**-74**	**-0.7%**

Notes: CAAGR = Compound average annual growth rate. Other includes agriculture, fishing, transformation and other non-energy use.

Gas demand in the EU **industry** sector peaked in 2000, at 145 bcm. A 20% decline since then can largely be attributed to declines in energy intensity following a shift from heavy to light industry and from industry to services. In the New Policies Scenario, industrial gas demand declines by a further 12% to around 100 bcm in 2040. All energy-intensive branches of industry see their gas demand decline slightly, largely because of economic restructuring and efficiency improvements rather than a shift to other fuels and technologies. Remaining gas demand in industry by 2040 is mainly for light industry (such as food and manufacturing) and for process heat above 400 °C (for example in the chemical industry), where there are fewer readily available low-carbon options. Outputs from energy-intensive industries remain sensitive to global macroeconomic conditions and the industrial competitiveness of Europe in relation to other regions.

Transport is a minor natural gas-consuming sector in the European Union, accounting for less than 1% of demand, but it grows at a rate of 4% per year in the New Policies Scenario. The bulk of the increase in gas use comes from passenger cars, for which promotion programs are already in place today in some EU member states. There is also growth in LNG bunkering for domestic and international shipping, stemming from the implementation of new International Maritime Organization standards on sulfur content of marine fuels in 2020.

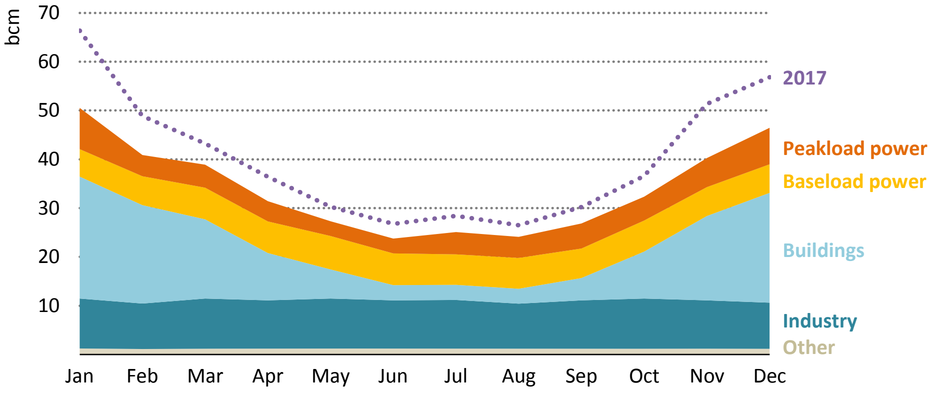
European peak gas demand

The gas infrastructure that is in place today in the European Union was designed to handle marked seasonal swings. The EU's winter gas consumption (October-March) is almost double that of summer (April-September), with the majority of additional demand required for heating buildings. Power generation forms a relatively small part of overall peak demand: deliveries to power plants made up only about one-fifth of the EU's peak daily gas demand in 2017. Whether Europe's gas infrastructure is sufficient to handle seasonal and short-term swings in the future depends to a large extent on the evolution and composition of peak demand.

Examining the evolution of peak demand requires much greater granularity in demand modelling, especially for the power and buildings sectors. For this analysis, we constructed individual peak gas load outlooks for all EU countries, using the results of our hourly power sector model (see Box 8.6) as well as detailed analysis of the outlook for the buildings sector. The results at EU level suggest that the peak in gas demand in the electricity sector increases by an additional 50% in 2040 compared with today. This is the result of a more significant role for gas in balancing an increasing share of variable renewables-based electricity generation (although the peak in gas demand does not necessarily occur during peak load power generation, meaning the contribution of gas to peak power demand declines over the projection period). The increased flexibility requirements, however, are offset by a drop in the role of gas in providing baseload power supply, and the net effect is a modest reduction in overall gas demand for electricity. Meanwhile, the drop in gas consumption in buildings, largely as a consequence of improved efficiency, has a significant effect on the seasonality of gas consumption. By 2040, monthly peak demand for gas overall is a third lower than in 2017 (Figure 4.17).

This trajectory of gas demand has significant commercial implications. The slow erosion of peak demand for heating implies an even more pronounced flattening of the spread between summer and winter gas prices, further challenging the economics of seasonal gas storage. With the anticipated phasing out of coal-fired power plants, there is less potential for commercially driven gas-to-coal switching, and increased need for gas to maintain power system stability, thereby favouring short-term storage. The demand remaining on the distribution grid (for example from households and small businesses) is largely weather dependent and therefore far less responsive to changes in price. Nevertheless, higher operating costs for ageing infrastructure will need to be recovered from a diminished customer base, further reinforcing longer-term fuel switching.

Figure 4.17 ▷ Seasonal gas demand in the European Union in the New Policies Scenario, 2040



Despite a 50% increase in the peak of gas demand in the electricity sector, the efficiency-driven drop in consumption for space heating leads to an overall decline in peak demand

The dilemma for policy makers is that, while the utilisation and profitability of Europe's gas infrastructure might decline, it still fulfils an indispensable role in ensuring security of supply. It might be needed less in aggregate, but when it is needed during the winter months there is – for the moment – no obvious, cost-effective alternative to ensure that homes are kept warm and lights kept on: the amount of energy that gas delivers to the European energy system in winter is around double the current consumption of electricity. Moreover, the importance of this function and the difficulty of maintaining it both increase as Europe proceeds with decarbonisation: that is why options to decarbonise the gas supply itself are gaining traction (notably with biomethane and hydrogen). Further electrification of space heating would naturally reduce direct gas use in buildings, but would transfer that seasonality to the electricity sector, where gas-fired power would again be the fallback option (see Chapters 7 and 8).

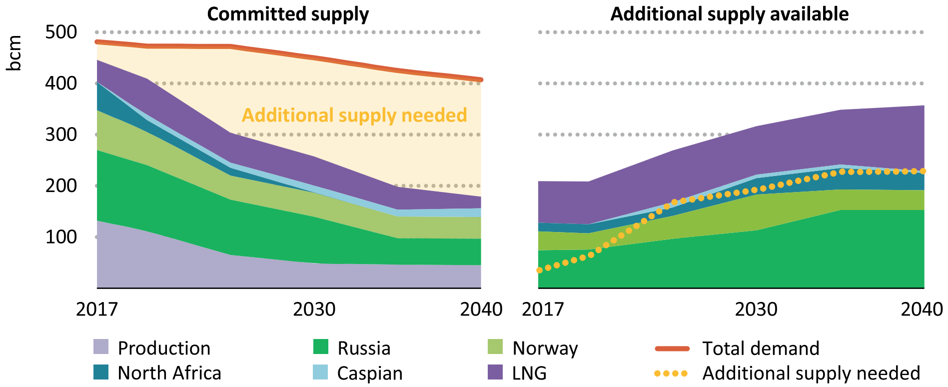
Supply: falling EU gas production keeps imports strong

Natural gas production in the European Union has been on a declining trajectory since 2000. This trend is mainly a result of resource depletion (most notably in the North Sea) and policies to tackle the problem of seismic activity at the Groningen gas field in the Netherlands. Some countries take considerable efforts to counter or decelerate the decline of their domestic gas production. However, the prospects for a significant expansion of domestic production are remote: the maturity of existing offshore fields in the North Sea limits the upside to marginal production additions, and many European countries have decided against pursuing onshore shale gas. Overall, gas production within the European Union is projected to fall from 132 bcm today to 45 bcm in 2040.

This means a high level of reliance on imported gas. The European Union is the largest gas-importing region in the world, and Russia is its largest supplier. In 2017, Russia exported a record level of 174 bcm to the EU countries, nearly half of the EU's total imported gas. The second-largest supplier, Norway, also set a record level of exports to the EU countries at 107 bcm; together, the two countries provided 75% of the EU's total gas imports. Other sources of piped imports into Europe have been limited by supply-side constraints. Algeria's export potential is expected to stagnate owing to robust demand growth and the uncertainty around the depletion of its largest gas field, Hassi R'Mel, while political unrest continues to cast a shadow over gas exports from Libya.

European gas supplies are broadly split between committed volumes and those for which choices remain. Committed volumes are those that flow more or less regardless of changes in natural gas prices. This category includes domestic production, which tends to run at full capacity, as well as the minimum volumes of gas required under long-term take-or-pay import contracts (for both piped gas and LNG). As shown in the left-hand side of Figure 4.18, the vast majority of gas consumed in Europe in 2017 falls into this category. Over time, however, as long-term contracts expire and domestic production declines, Europe requires additional supplies that are either uncontracted or above take-or-pay levels.

Figure 4.18 ▷ European Union committed gas supply and options to supply remaining import demand in the New Policies Scenario



The European gas market can choose from a range of available LNG and pipeline gas supplies to satisfy its remaining import demand

Notes: Additional supply available is: Russian, Norwegian and Algerian contracted volumes above take-or-pay levels, plus remaining export capacity through existing entry points (subject to production constraints); uncontracted capacity on the Caspian route; uncontracted LNG capacity available to the EU internal gas market.

The additional need for imports can mainly be met through a combination of LNG and piped gas from Russia (right-hand chart of Figure 4.18). Other imported pipeline sources are unlikely to be able to offer much optional supply. Norwegian gas supplies to Europe typically run at full capacity and look set to remain relatively stable until the early 2030s, after which declines in the North Sea reduce the volumes available for export. In North Africa, high levels of demand growth and geopolitical instability raise questions over its future export potential. Though strategically important, the Southern Gas Corridor[6] adds only modest volumes to Europe's overall import balance, while potential options to reinforce this corridor are not yet sufficiently advanced to be included here.

Given that the most significant spare import capacity to satisfy Europe's incremental import requirement lies with Russian piped gas and LNG, the stage is set for competition between these sources. In the New Policies Scenario, Russia remains the largest single source of supply to the European Union: even though the volumes supplied decrease from today's record highs, Russia is still projected to supply 140 bcm to the European Union in 2040, or 37% of the total 385 bcm imported in that year.

Nevertheless, there are uncertainties about how this will play out. To a degree, this is simply a question of relative costs: which suppliers can most profitably bring gas to consumers in different parts of the continent? Closely linked to this is the question of world market conditions, especially for LNG: in an increasingly flexible and liquid global market for gas, exporters are not going to look to Europe as a market if there are more lucrative opportunities elsewhere. But strategic considerations also come into play on both sides: these could include pricing and marketing strategies on the part of the sellers, such as a willingness to sell pipeline gas at a level below the long-run marginal cost of most LNG exporters, and strategies on the part of buyers to ensure a diverse mix of import sources. In addition, there are questions of physical infrastructure and regulations across Europe, including the question that we return to in the analysis below: could a poorly functioning internal market and/or infrastructure bottlenecks leave some consumers without much choice when it comes to gas supply?

Gas infrastructure in Europe's Energy Union

Allowing gas to flow more efficiently within the European Union and ensuring that member states have access to a diverse portfolio of supplies requires a fully functioning internal EU gas market, and much effort has been devoted to this objective. Wholesale markets are gradually improving, with an increasing number of buyers and sellers freely trading gas across borders. The Title Transfer Facility in the Netherlands is emerging as Europe's most liquid hub and relevant price benchmark, offering forward trading and hedging options to a growing pool of market participants. Spot trading is growing in other hubs in Europe, leading to prices that increasingly reflect short-term fundamentals across markets. This is supported by shared rules, known as network codes, which set out the conditions for the use of infrastructure, and ongoing efforts to harmonise national approaches to transmission tariffs. Since the early 2010s, there have also been a number of investments in bidirectional pipelines, regasification terminals and pipeline import infrastructure. In addition to

6. The Southern Gas Corridor refers to the set of planned infrastructure projects to diversify the EU's supply mix, by opening up a route for Caspian gas to reach EU markets via Turkey.

improving market liquidity, this infrastructure has reduced Europe's vulnerability to gas supply disruptions.

Improvements in EU market operation are also partly a consequence of market and regulatory pressure on Gazprom, Russia's sole pipeline gas exporter to Europe. A succession of arbitration cases and anti-trust investigations has seen Gazprom's pricing and contracting structures adjusted to the demands of liberalising European gas markets. Gazprom now integrates European spot market benchmarks in its pricing formulas for the majority of its contracts with EU buyers. Controversial elements in its supply agreements, such as destination clause restrictions, have been removed and fixed delivery points have been revised.

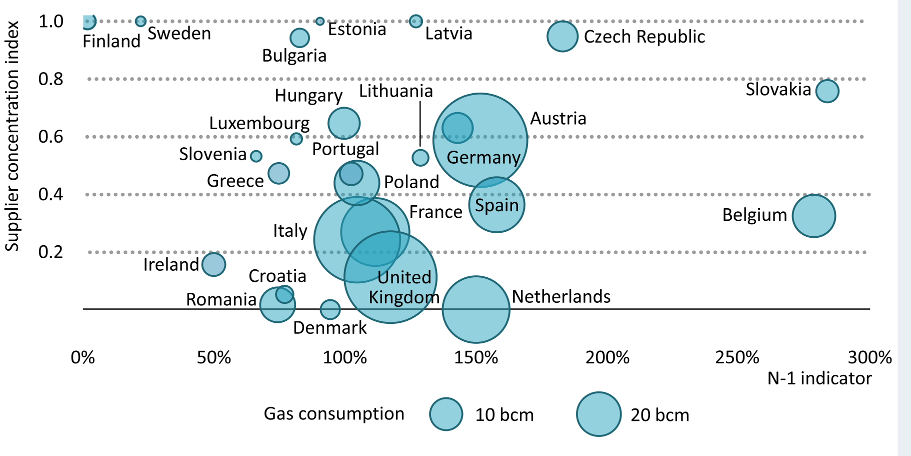
However, despite improvements over the past years, several countries in Europe are isolated from gas hubs and remain sensitive to dependence on single gas suppliers. Persistent wholesale price differences exist between northwest Europe, where liquid gas hubs provide robust price formation that reflects short-term market fundamentals, and central and southeast Europe, where gas flows continue to be largely underpinned by traditional long-term oil-indexed contracts with single suppliers. Tariff "pancaking" – whereby traders incur multiple charges to transport gas across markets – as well as the hoarding of long-term capacity rights remain barriers to the efficient utilisation of existing infrastructure. Meanwhile, regional co-operation related to gas security remains challenging. Political sensitivities and commercial constraints may render member states unwilling or unable to pool their resources with neighbours and, in practice, responsibility for security of supply still rests with national operators and regulators. Many gas infrastructure projects in Europe, particularly those designed to better insulate member states from supply shocks, are either uneconomic or may only provide benefits to a subset of stakeholders; moreover, third-party access rules challenge the way such large-scale infrastructure in Europe is typically financed, i.e. through long-term bilateral commitments between buyers and sellers of gas.

To address the difficulties of implementing projects with wider benefits, the European Commission, supported by pan-European bodies such as the European Network of Transmission System Operators for Gas (ENTSOG) and the Agency for the Cooperation of Energy Regulators, promotes regional initiatives and platforms encouraging gas market actors to work together to identify projects that enhance collective security. Through the Projects of Common Interest (PCI) list and a focus on a number of "priority corridors", the European Union has offered to financially support an additional 10 000 km of gas transmission pipelines, five LNG terminals and five underground storage sites. According to ENTSOG, EU gas infrastructure projects are expected to involve a combined investment cost of nearly $100 billion up to 2030 (ENTSOG, 2017).

Box 4.3 ▷ Measuring Europe's gas security

Two indicators are often used to measure the security and diversity of gas supply in European countries. The first is a supplier concentration index, where lower values indicate higher supply source diversity. The second is an "N-1" value that calculates the capacity available to the market area in case of the loss of the single largest gas supplying infrastructure, with a figure above 100% indicating sufficient alternative capacity to meet peak demand. As shown in Figure 4.19, several EU member states – particularly those on the EU's periphery – rely on only one source of gas and do not possess sufficient infrastructure to remedy this. In some cases, vulnerabilities are partly alleviated by hosting transit pipelines, which are sized to accommodate onward deliveries to consumers with larger gas requirements, though this is not without its own difficulties during periods of supply disruption.

Figure 4.19 ▷ Indicators of gas supplier diversity and infrastructure resilience in EU countries, 2016



Secure, liquid wholesale gas markets in Europe need multiple sources of gas; a number of EU countries rely on a limited number of suppliers

In the New Policies Scenario, the N-1 values for most EU member states comfortably exceed 100%: assuming full implementation of planned infrastructure measures, the N-1 value for the European Union as a whole rises from 130% in 2017 to 170% by 2040, suggesting far stronger resilience. The EU's supplier concentration index, which was 0.33 in 2017, remains broadly flat in the New Policies Scenario, as higher import dependence is offset by increased import diversity. The caveat is that both aggregated values, which notionally suggest sufficient gas security, rely on a fully functioning internal market that is able to efficiently utilise infrastructure to allow gas to be redirected to where it is needed.

The achievement of the EU's efficiency and renewable targets may appear to challenge the idea of further investment in gas-based infrastructure. However, the majority of PCI projects are not aimed directly at meeting growth in demand, but rather at removing physical bottlenecks to the completion of an internal gas market and at enhancing the security and diversity of gas supply (Box 4.3). Moreover, the additional infrastructure could put downward pressure on wholesale gas prices by giving member states stronger bargaining power as a result of their enhanced access to alternative sources of gas supplies, thus also improving the affordability of gas.

As shown previously, EU member countries have a range of potential supply options in the face of dwindling domestic production (see Figure 4.18). The projections in the New Policies Scenario suggest that Russian gas is well placed to maintain a strong position in the European gas import mix: even though LNG imports grow, Russia remains the largest single supplier, capturing over half of the European Union's additional supply requirements in the period from 2017-2040 (defined in Figure 4.18) and maintaining a market share of more than 30% of total EU gas demand. But what matters in practice, both for security of supply and price, is whether consumers – especially in eastern and southeast Europe – are choosing Russian gas as the most competitive among a range of import options, or because they have little choice.

To consider this issue we developed a new European gas infrastructure model, which allows us to examine trade flows and potential bottlenecks on a disaggregated country-by-country basis across the entire European single market.[7] To test the ability of consumers across Europe to access alternative sources of supply, we constructed two contrasting cases, both of which are based on the same supply and demand projections as those in the New Policies Scenario. We consider:

- An "Energy Union" case, where the vast majority of PCI projects are successfully implemented[8], there are no regulatory impediments to the free flow of gas across the single market and solidarity principles are broadly applied during supply interruptions. This applies as well to Contracting Parties to the Energy Community in southeast Europe.
- A "Counterfactual" case, where the majority of PCI projects are not constructed, flows of gas outside northwest Europe continue to suffer from contractual and regulatory congestion, and EU countries do not co-operate with one another, nor with the Energy Community countries, during periods of system stress.

7. EU-28, plus Switzerland and countries of southeast Europe that are contracting parties to the Energy Community Treaty: Albania, Bosnia and Herzegovina, the former Yugoslav Republic of Macedonia, Kosovo, Moldova, Montenegro, Serbia and Ukraine. Georgia is not included in this analysis, although part of the Energy Community, it is not contiguous with the single market; Turkey and Belarus, Iceland and Norway are the only countries in our "Europe" aggregate that are not included.

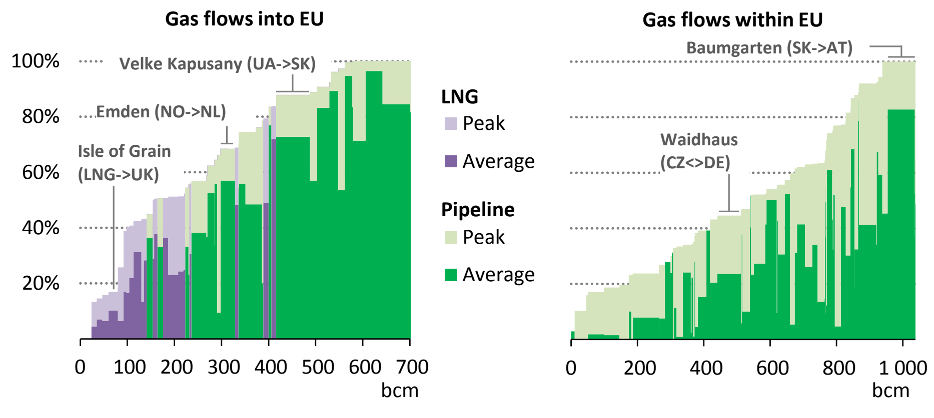
8. We assessed infrastructure development from a bottom-up, project-by-project perspective. Some PCI projects, particularly those competing with one another, are assumed not to go ahead in the analysis. Others had their commissioning dates adjusted to better reflect current market and political conditions.

European gas infrastructure and gas import options

At present, import infrastructure in the European Union is utilised very unevenly (Figure 4.20). Pipeline gas continues to be cost-competitive with LNG, meaning high overall utilisation rates – over half of the EU's import pipelines operate at peaks above 80%. By contrast, the EU's LNG import infrastructure is almost all on the left-hand side of the graph, much of it with utilisation rates well under 50%.

Once inside the European Union, there are few bottlenecks to impede gas travelling through cross-border pipelines, with less than a fifth of volumes running at a peak greater than 80%. Moreover, the spread between peak and average utilisation of infrastructure is wider than for imports, implying more slack in the market. This suggests that much of the EU's gas infrastructure is often under-utilised, with considerable spare capacity across storage and intra-EU transmission pipelines, even when taking into account peak monthly demand requirements.[9] However, there are both physical and contractual constraints within the European Union that prevent some import capacity from being fully utilised: roughly 80 bcm, or 40%, of the EU's LNG regasification capacity cannot be accessed by neighbouring states.

Figure 4.20 ▷ Utilisation of main European Union gas import and internal cross-border capacity, 2017



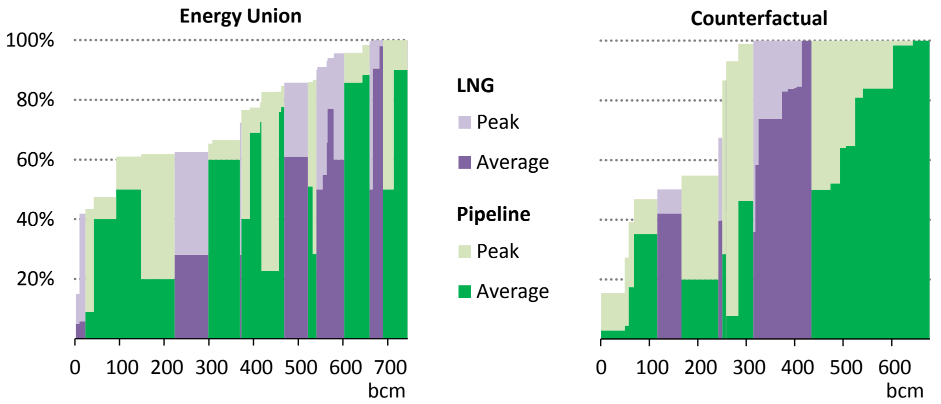
Many import pipelines run at full capacity during peak months, while LNG terminals are underused. Overall, there is ample capacity for gas transmission between EU countries.

Notes: Figure shows average and peak utilisation levels for cross-border infrastructure in 2017, using monthly flow data. "Gas flows into EU" include all entry points from non-EU to EU countries, split between pipeline and LNG terminals. "Gas flows within EU" are those between EU countries and include interconnection points largely reserved for transit pipelines crossing multiple borders. Highlighted interconnection points shown for illustration purposes. <> denotes bidirectional capacity, with flows calculated as the weighted average utilisation in both directions.

9. It is worth noting that more granular stresses may appear when analysing daily demand, as well as significant peak periods (such as those with a 1-in-20 year probability of occurring, as applied in EU regulations on security of supply).

Pursuing additional infrastructure, and maintaining what already exists, may appear to run against the reality that low-cost pipeline gas via traditional supply routes stands ready to satisfy Europe's incremental import requirements. Figure 4.21 shows how the completion of the internal market helps reduce the congestion that would otherwise arise in a Counterfactual case: almost half of the EU's pipeline import infrastructure runs at nearly full capacity in 2040 in the Counterfactual case, compared with only 22% in the Energy Union case. Without planned regasification terminals in Croatia, Greece and Poland, the EU's LNG import capacity can only operate at a peak utilisation rate of 85% before bottlenecks begin to emerge: congestion on north-south interconnections prevents northwest European LNG terminals from transmitting onwards all the gas needed elsewhere, and the resulting congestion rent amounts to almost $40 billion over the period 2017-40.

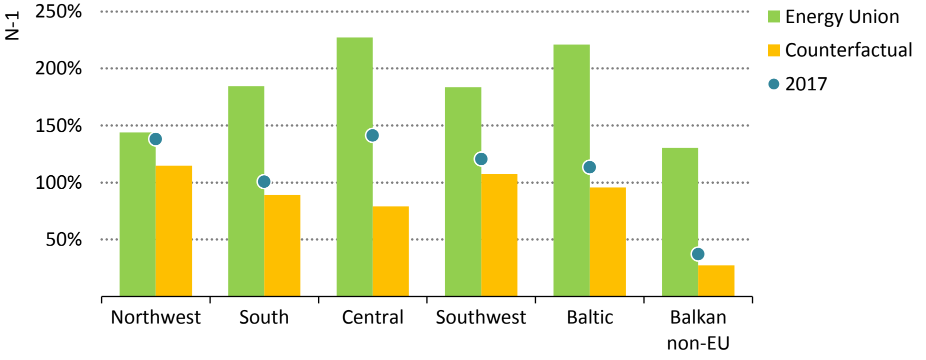
Figure 4.21 ▷ Utilisation of import infrastructure in 2040, Energy Union case versus Counterfactual case



A well-functioning market which allows gas to flow freely within the European Union significantly reduces the risk of congestion and supply problems

Moreover, in the Counterfactual case – with restricted trade and insufficient infrastructure between regions – the N-1 value falls below 100% in 2040 in some regions, as a consequence of reduced domestic production and less intra-EU transmission capacity (Figure 4.22). The Baltics, central and southern European countries in particular show a higher degree of exposure. By contrast, in the Energy Union case, with additional LNG terminals in southeast Europe as well as transmission lines crossing multiple borders (e.g. the Baltic Connector linking Estonia and Finland; Gas Interconnection Poland-Lithuania; Interconnector Greece-Bulgaria and Bulgaria-Romania-Hungary-Austria) the N-1 values significantly increase, and the majority of countries in the region are able to access at least three other sources of gas.

Figure 4.22 ▷ Regional N-1 values in 2040, Energy Union case versus Counterfactual case



Congestion on existing infrastructure and insufficient new capacity could lead to an inability to access alternative supply sources in some European regions

Notes: *Northwest:* Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, United Kingdom, Switzerland (exceptionally, Switzerland is included among the EU countries for this analysis), United Kingdom; *South:* Bulgaria, Croatia, Greece, Italy, Romania, Slovenia; *Central:* Austria, Czech Republic, Hungary, Poland, Slovakia; *Southwest:* Portugal, Spain; *Baltic:* Estonia, Finland, Latvia, Lithuania, Sweden; *Balkan non-EU:* Albania, Bosnia-Herzegovina, Kosovo, Former Yugoslav Republic of Macedonia, Montenegro, Serbia. Excluded from the figure: Cyprus and Malta.

This suggests that there may be a way to ensure a secure, diversified supply mix while also allowing choices about sources of gas in a competitive internal market based on their relative costs. Both objectives can be addressed by robust infrastructure and liberalised trading of gas across borders. In the Energy Union case, the value of additional LNG and pipeline infrastructure derives less from the absolute volumes imported than from their contribution to diversification, the benefits of which include not just security of supply, but the ability to negotiate better deals with suppliers as a result of having a choice of alternatives. Our modelling shows that actual utilisation of several intra-EU pipelines only arises during security of supply crises or when alternative sources are able to outcompete Russian gas. Nevertheless, their presence, along with transparent and liquid spot markets, is what counts. Moreover, the cost of maintaining volume optionality is lower across a larger market, implying that a functioning EU internal market can reduce the per-unit costs of insurance against future supply disruptions.

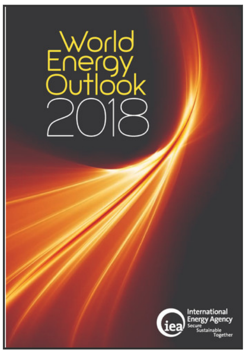
That said, being on the PCI list is not a prerequisite for, or a guarantee of, eventual construction, and there are other projects on the horizon that are not on the list that could very plausibly change the picture. The completion of Nord Stream 2 is the obvious example. The debate over Nord Stream 2 underscores the tension between different visions of where the European market is today and where it might go in the future, a tension that is encapsulated in our two cases. The Energy Union case is one in which a well-functioning European market becomes part of a globalising gas market, meaning that European consumers – wherever they are – get enhanced access to competitive supply options. In this case, the physical location where gas enters Europe, and even the identity of the supplier, becomes less important. The Counterfactual case represents a concern that Europe's gas market may remain relatively fragmented and less efficient, an environment in which geography, suppliers and supply routes matter – especially in central and eastern Europe – and price differentials and bargaining power continue to vary widely across the continent.

Conclusion

The gradual projected decline in gas demand in the European Union means lower utilisation rates for cross-border transmission pipelines over time. However, gas infrastructure will remain a crucial security of supply asset for Europe, accommodating seasonal variations in both demand and supply, while alleviating the effects of extreme weather events. It will also become increasingly important for the electricity system, implying a higher degree of interdependence between gas and electricity security.

Our analysis indicates that the EU's current gas infrastructure can accommodate a wide range of supply configurations. However, this is only the case if gas is able to flow freely across borders, unencumbered by physical and regulatory constraints. Our Counterfactual case, in which infrastructure constraints persist and barriers to trade across Europe remain high, shows a Europe where access to alternative supplies of gas is constrained across many parts of central and southeast Europe. Under these circumstances, gas remains a more "political" commodity in these regions, with buyers remaining vulnerable during tight supply conditions.

Our analysis also indicates that a strong internal market can make better use of existing infrastructure. Hubs enable the marketing of gas futures, swap deals and virtual reverse flows, and thus remove the physical component from gas trade and allow molecules to be bought and sold several times before being delivered to end-users. This precludes much of the need for costly physical gas infrastructure and, in time, enables gas deliveries to be increasingly de-linked from specific suppliers. This puts greater emphasis on the efficient auctioning of available gas capacity between EU countries and the ability of liberalised markets to transport gas flexibly: short-term price signals rather than destination-inflexible delivery commitments become the main factor in determining whether flows can be directed to areas experiencing supply constraints. There are encouraging signs in this respect. Short-term and spot trading is increasing while planned infrastructure projects, if realised, will put all parts of Europe within plausible reach of multiple suppliers. Despite declining demand, therefore, there remains a case for new gas infrastructure. However, each project will require careful cost-benefit analysis, particularly as the debate about the pace of decarbonisation in Europe intensifies.



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