Shell LNG Outlook 2021

Royal Dutch Shell

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Gas and LNG have a key role to play in a decarbonising world

2020 saw new net-zero emissions (NZE) announcements at both national and regional levels. Natural gas can help lower overall emissions, whether in partnership with renewables to deliver a reliable energy choice or to power hard-to-electrify sectors. 65% of the growth in natural gas use in the next twenty years is expected to come from non-power sectors. LNG is expected to be the fastest growing source of natural gas.

LNG shows its resilience and flexibility in 2020

While COVID-19 derailed expected forecasts, LNG demand still grew with trade reaching 360 million tonnes in 2020. The industry reacted swiftly to changing market conditions, diverting cargoes to shifting demand centres and through adjusting supply. Prices remained volatile, hitting a record low before rebounding to record high in early 2021. New LNG supply investment decisions ground to a halt due to the pandemic-driven economic crisis.

Complementary spot and term contract structures and cleaner pathways to drive LNG growth

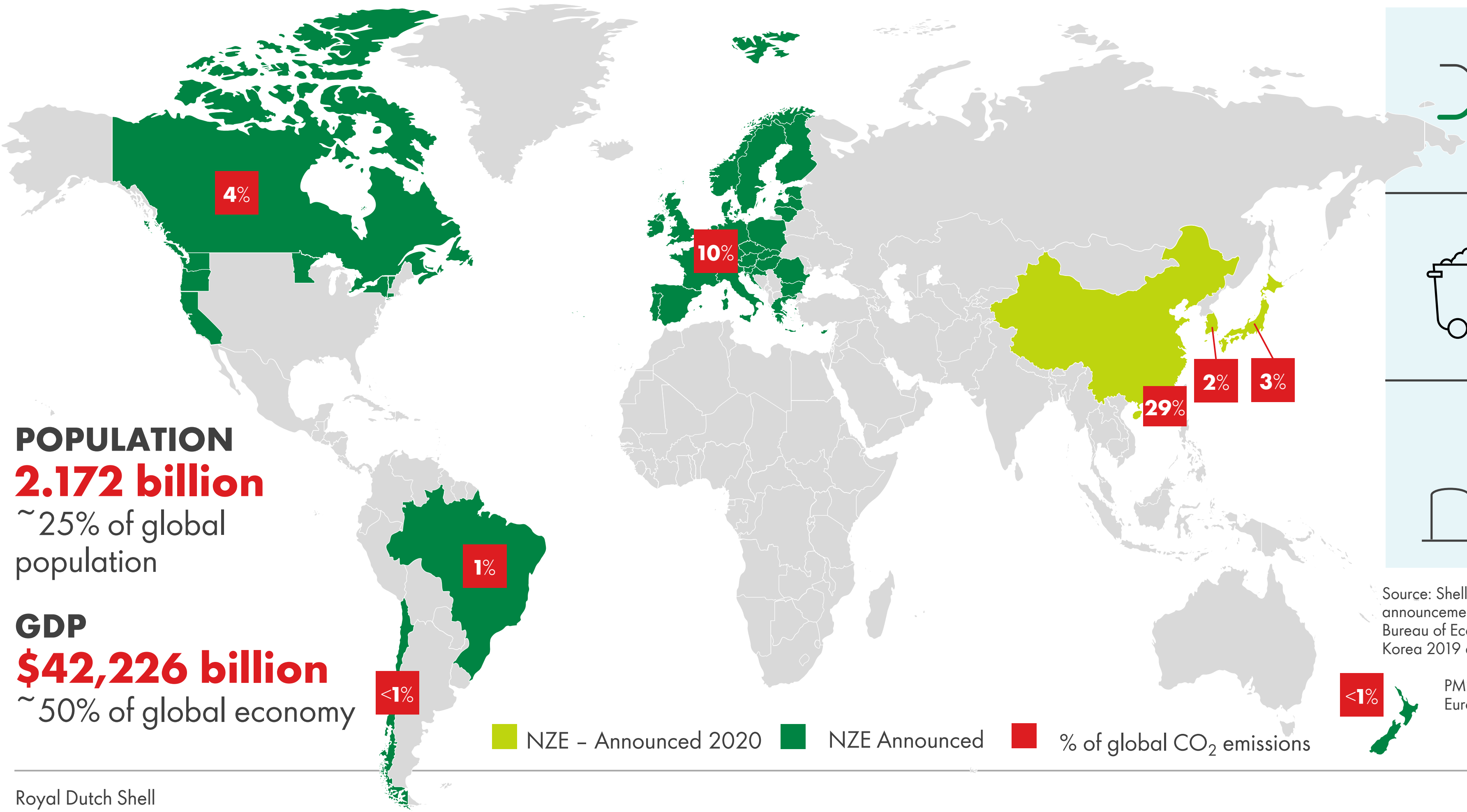
LNG demand is expected to grow steadily with a supply-demand gap estimated to emerge in the middle of the current decade. With an increasing number of buyers and suppliers, the industry has evolved to offer a wider choice of commercial structures to meet changing needs. Against a backdrop of increasing NZE targets, the industry will need to further innovate to offer cleaner energy supply.

01

Gas and LNG have a key role to play in a decarbonising world

Three of the ten highest CO_2 emitting countries announce net-zero emissions (NZE) targets during 2020

NZE announcements globally



POPULATION
2.172 billion
~25% of global population

GDP
$42,226 billion
~50% of global economy

South Korea 2030's energy outlook

24
coal-fired power plants to switch to LNG

PM2.5
REDUCTION
-57%

06
coal-fired power plants to shutdown

300%
increase in renewable capacity

Source: Shell interpretation of Global Carbon Atlas, National Policy announcements, UNFCC, Climate Action Tracker, World Bank, CDP and US Bureau of Economic Analysis and Ministry of Trade Industry and Energy South Korea 2019 and 2020 data

PM2.5: Particulate Matter 2.5 micrometres
Europe is EU 27+3, (Norway, Switzerland, UK)

Gas demand projected to grow and play a key role in decarbonising sectors

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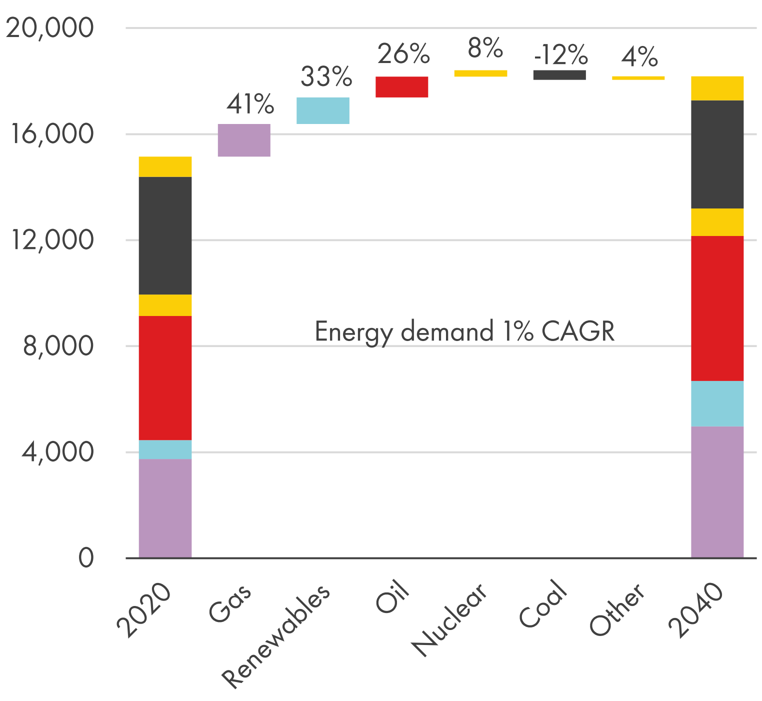
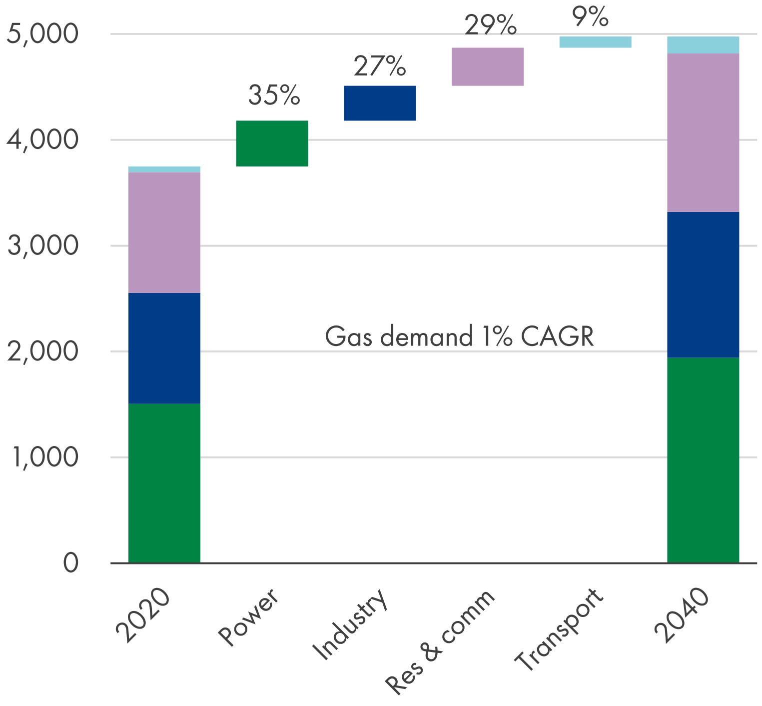
Global energy demand growth by fuel type

BCM



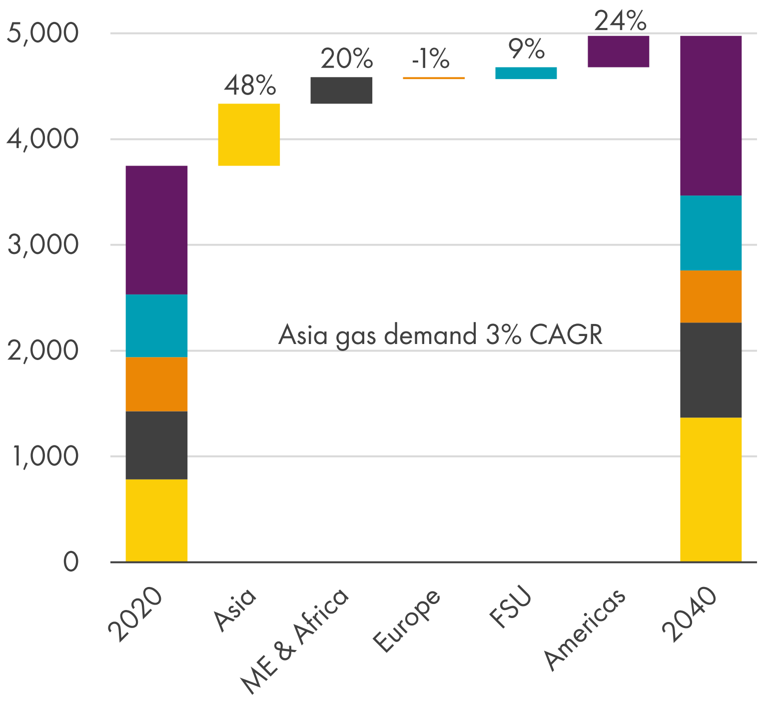
Global gas demand growth by sector

BCM



Global gas demand growth by region

BCM



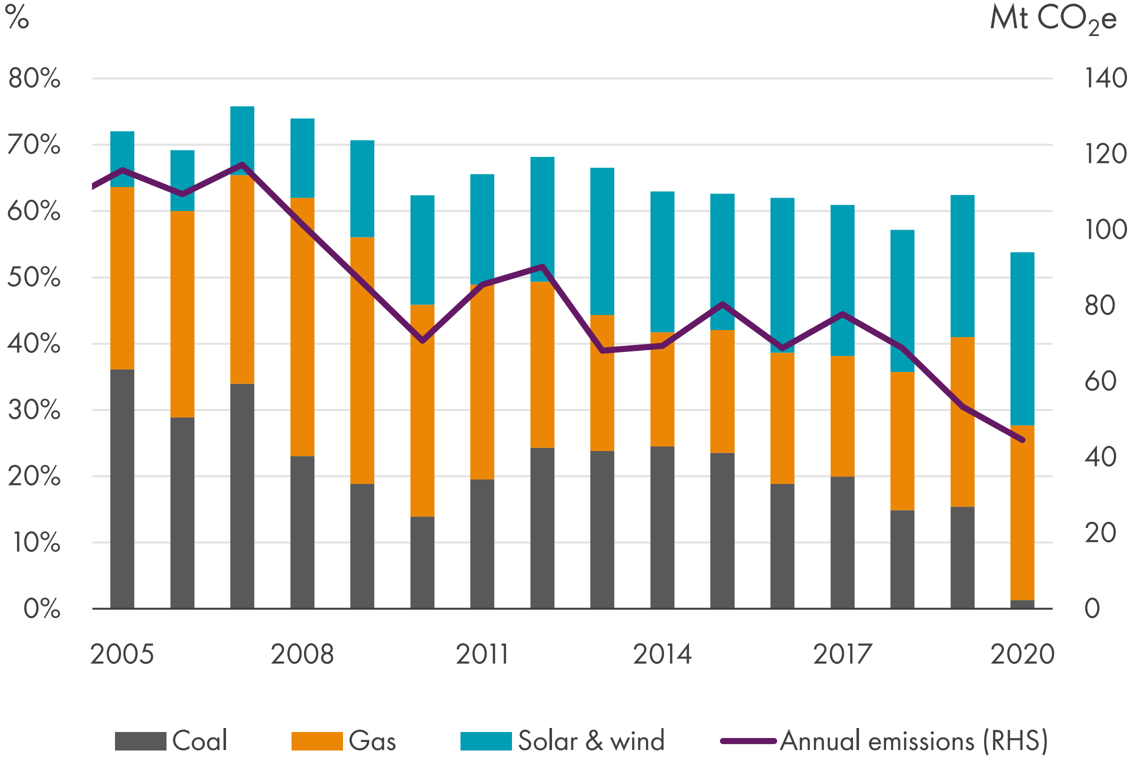
Source: Shell interpretation of Wood Mackenzie H1 2020 data

CAGR - Compound annual growth rate   Res & comm: Residential and Commercial

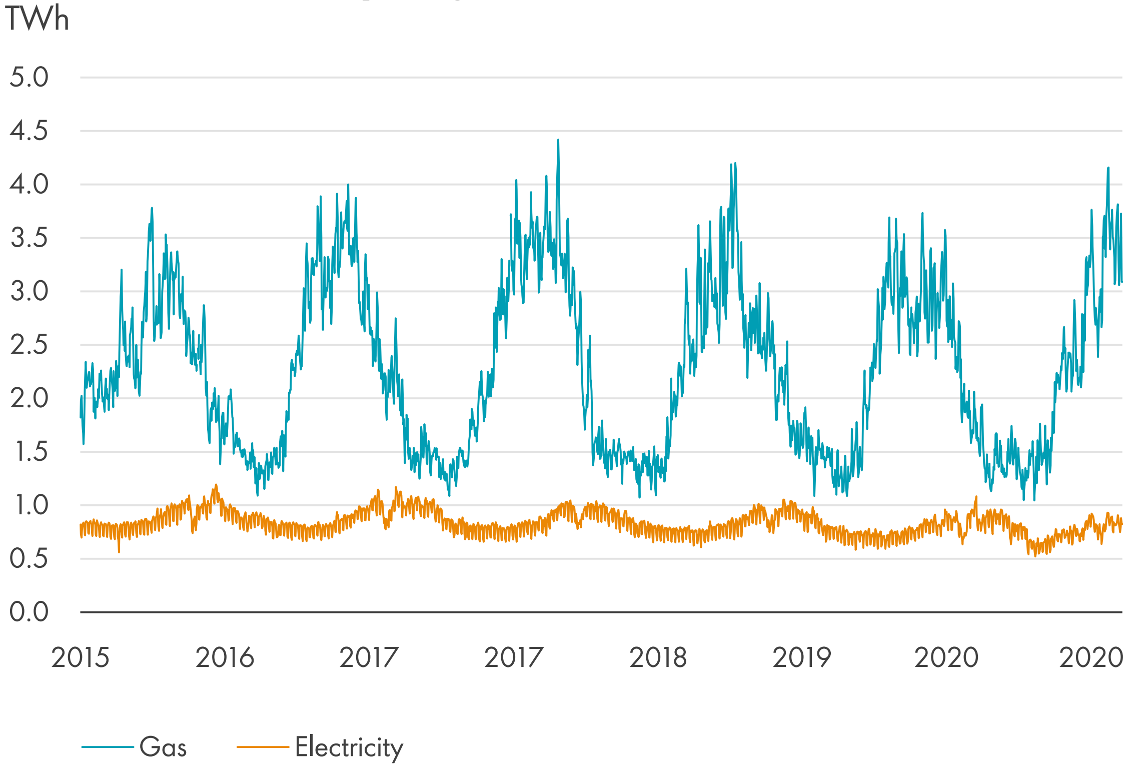
Gas is a reliable partner to renewable power and provides flexibility to meet seasonal heating demand

Shell
LNG Outlook 2021

Share of coal, gas & renewables in Spain power sector



UK total electricity & gas demand



Source: Shell interpretation of Wood Mackenzie, IEA, Aurora Energy Research, National Grid, Grid Watch UK 2021 and Sustainable Gas Institute White Paper 5 2020 data

Gas enables reduction of industrial emissions

Iron and steel sector benefitting from coal-to-gas switching

Benefits of using gas in the iron & steel sector

-36%
EMISSIONS

Coal-to-gas switching

36% CO_2 emissions saving through the use of natural gas, hydrogen and LNG for direct reduced iron (DRI) steel production

-85% -90%
EMISSIONS

Carbon capture & storage

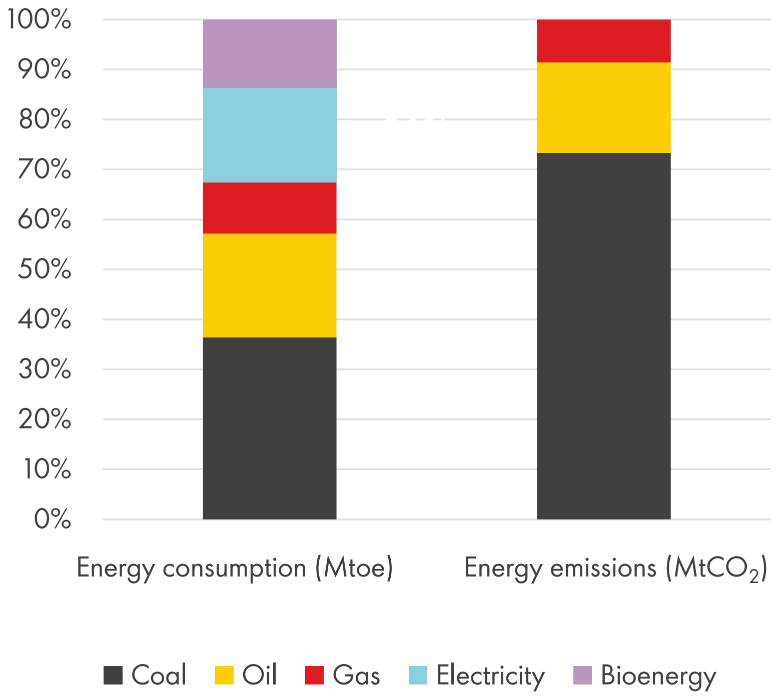
85-90% CO_2 emissions saving

-100%
EMISSIONS

Biogas & BECCS

86% CO_2 emissions reduction using electric arc furnace (EAF)*
Potentially negative when using biogas / bioenergy + CCS

2020 industrial energy use and emissions in India



Source: Shell interpretation of IEA ETP, Wood Mackenzie, worldsteel data 2020 data

* If electricity is sourced from renewable generation BECCS: Bioenergy carbon capture & storage Mtoe: Million tonnes of oil equivalent $MTCO_2$: Million tonnes CO_2

Uptake of gas in the road transport sector

Demand increasing as number of LNG-fuelled vehicles increase

In 2020, China's road transport sector consumed nearly **13 million tonnes of LNG**

3,000+
LNG stations in China

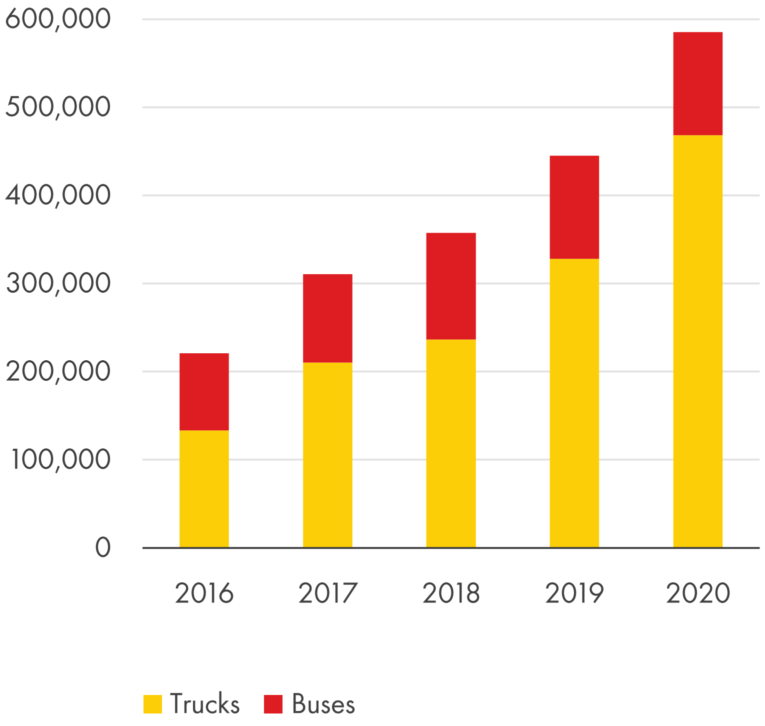
300+
in 21 countries across Europe

7.9 million tonnes
of LNG demand projected for road transport in Europe by 2030

40% of which is expected to be met with bio-LNG

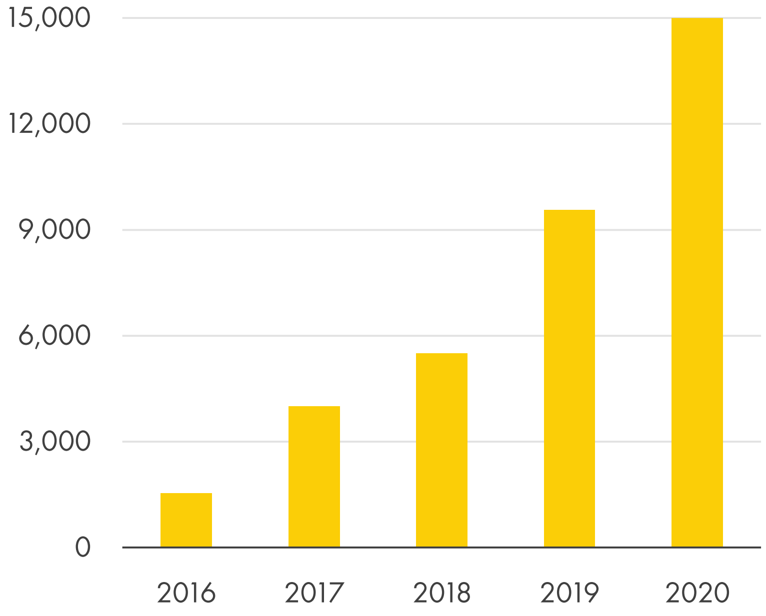
LNG-fuelled trucks & buses (China)

\# of vehicles



LNG-fuelled trucks (Europe)

\# of trucks



Source: Shell interpretation of NGVA 2020, Less Better, SCI China, CARTAC and other industry 2019 and 2020 data

Marine sector LNG demand grows as global bunkering infrastructure develops rapidly

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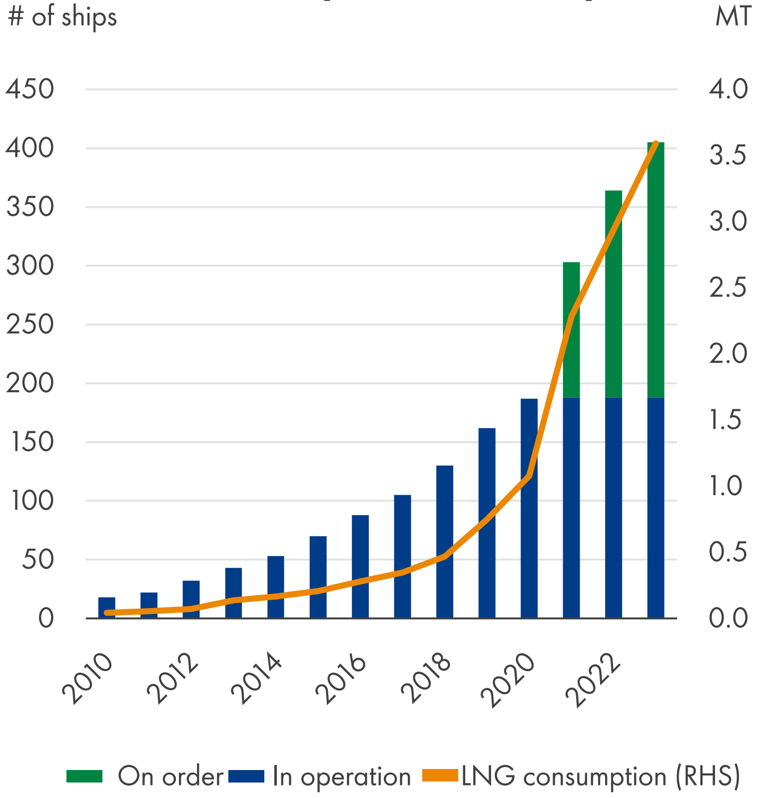
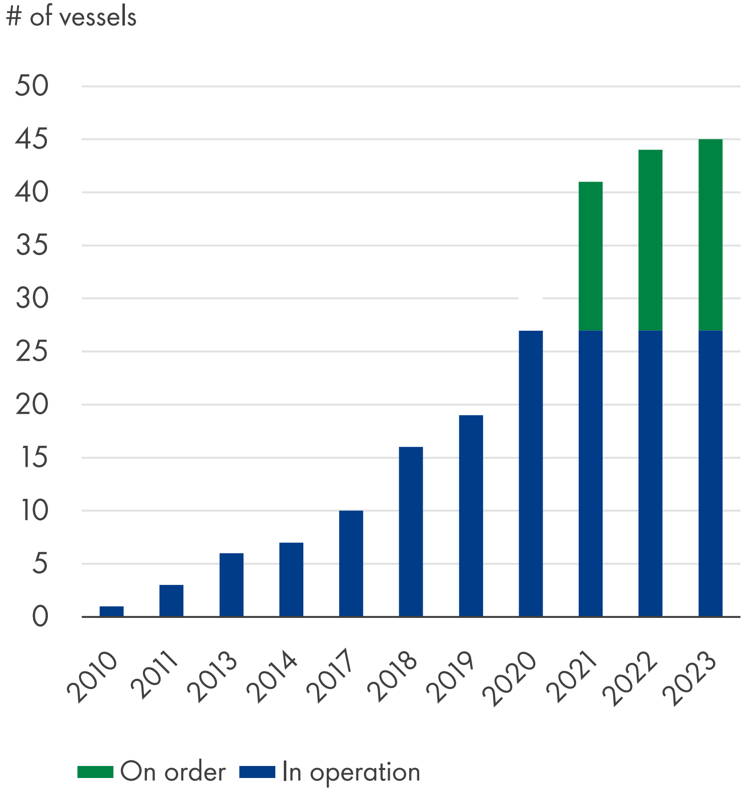
LNG fuelled ships & consumption

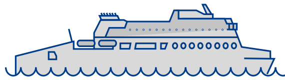


LNG bunker vessels



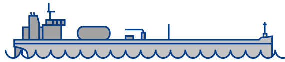
A choice of LNG enabling access to green financing

2017



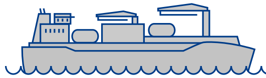
Brittany Ferries
LNG-powered ferry Honfleur

2018



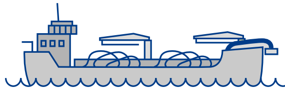
Sovcomflot
9 LNG-powered Aframax tankers

2019



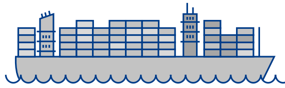
MOL
18,600 cubic metre bunkering vessel

2020



Van Oord
3 LNG-powered dredging vessels

2021



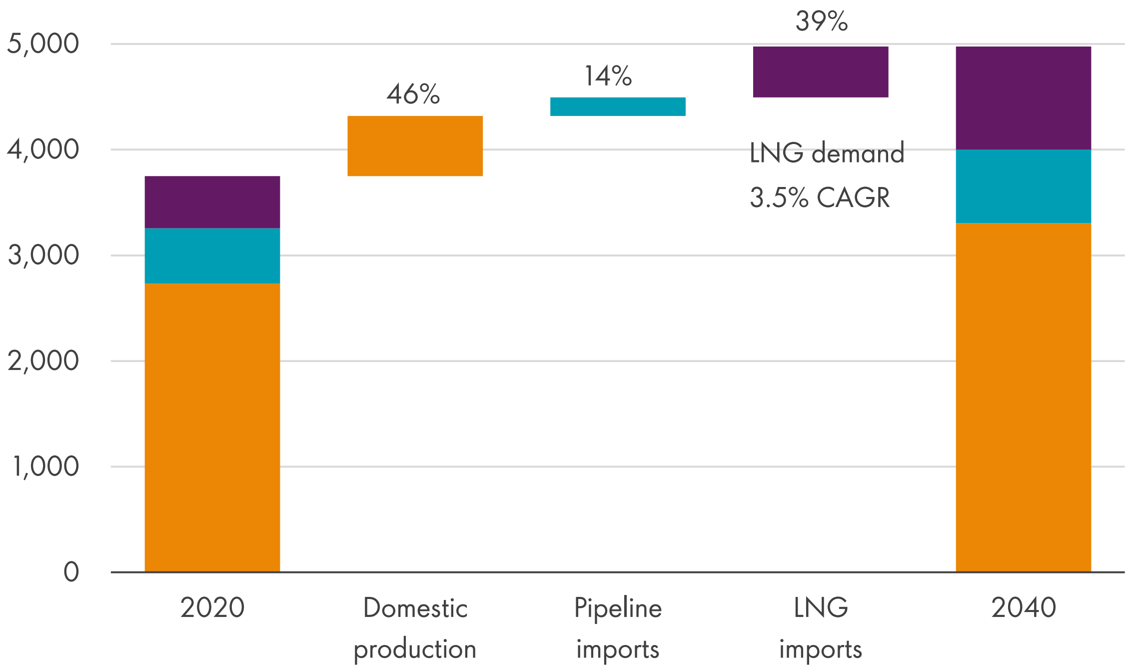
Hapag Lloyd
6 LNG-powered containerships

Source: Shell interpretation of DNV GL 2020 data and various news reports

LNG to play a pivotal role in meeting gas demand growth, particularly in Asia

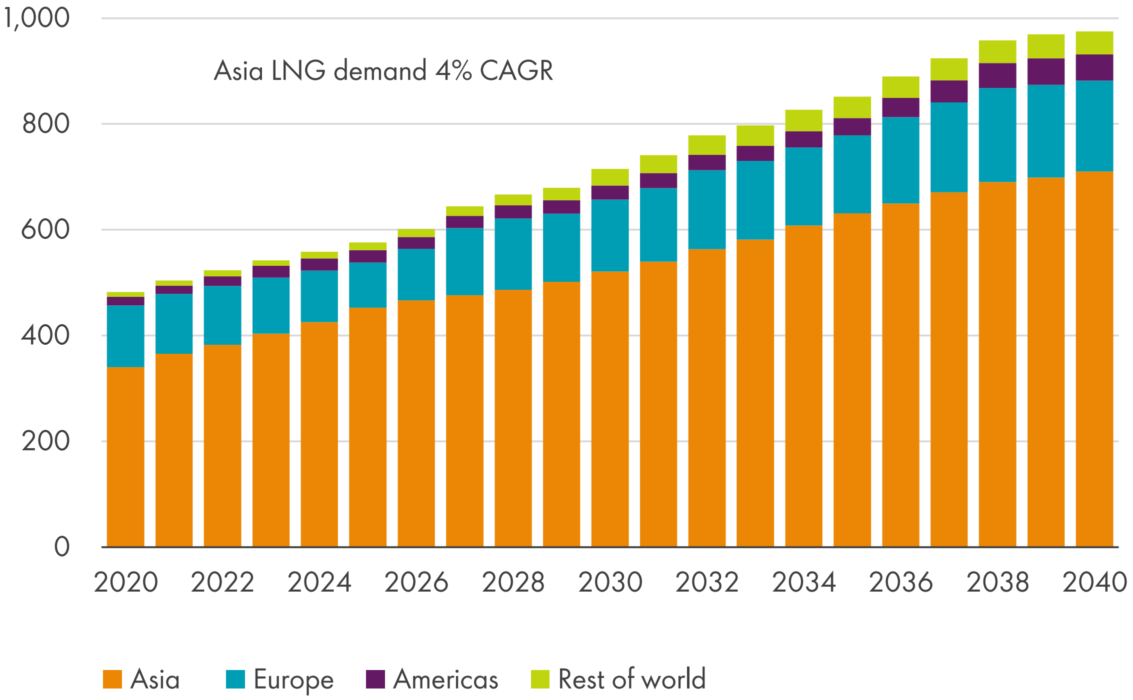
Global gas supply by source

BCM

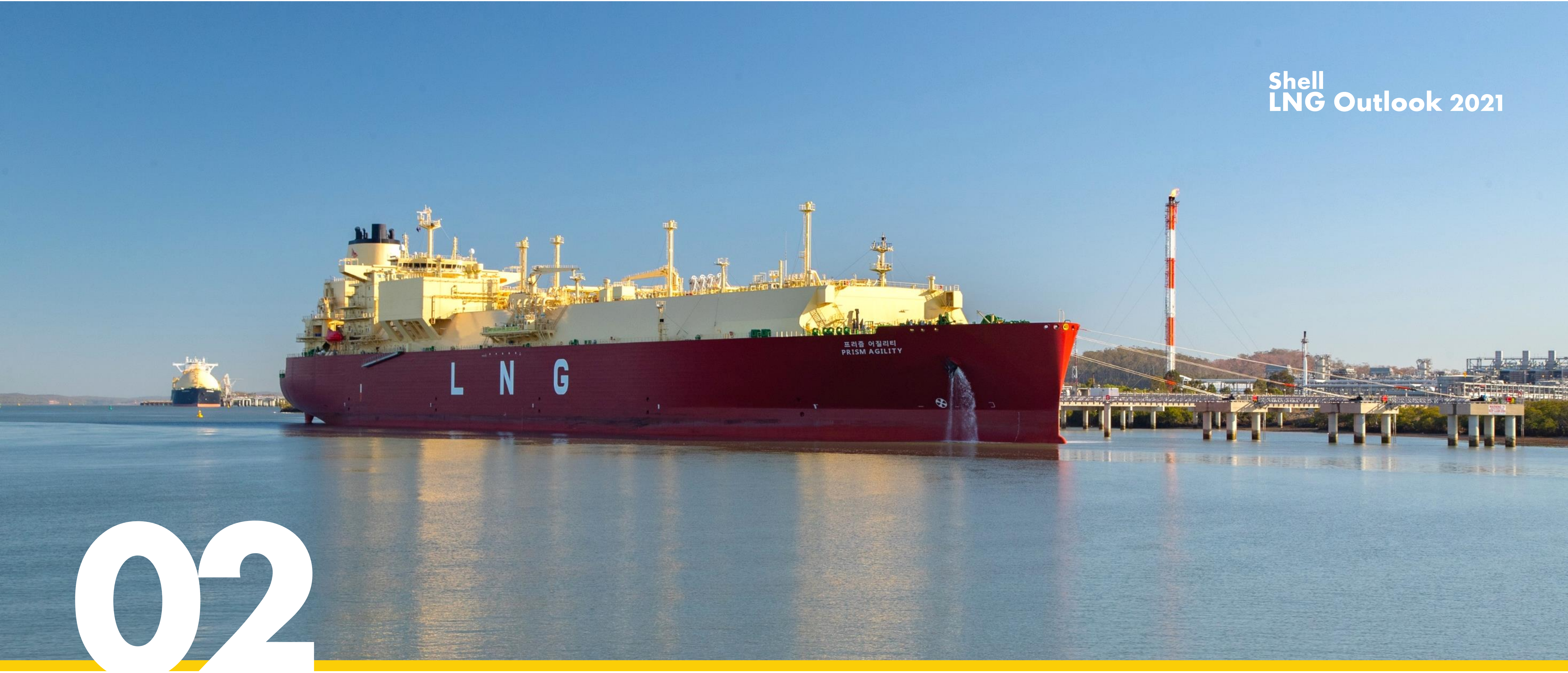


LNG imports by region

BCM



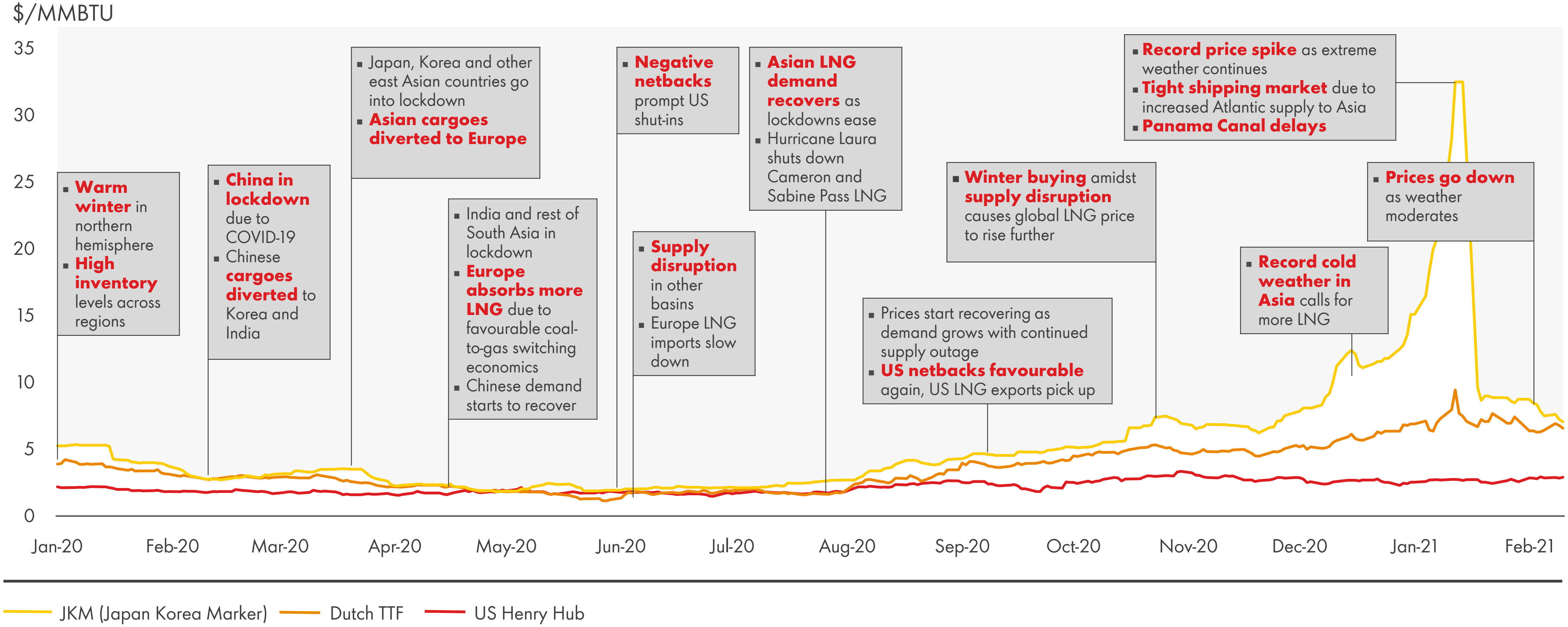
Source: Shell interpretation of Wood Mackenzie H1 2020 data CAGR: Compound annual growth rate



02

LNG shows its resilience and flexibility in 2020

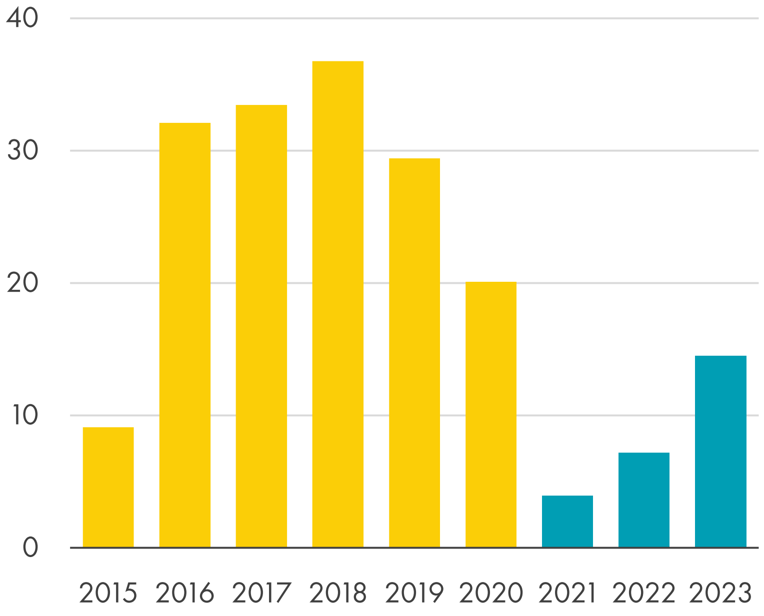
LNG shows resilience and flexibility in a rapidly changing environment



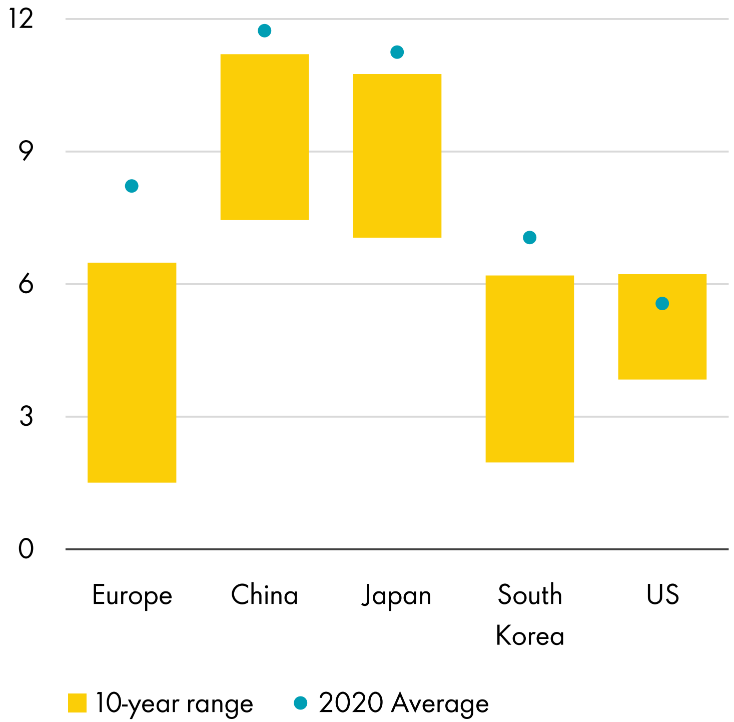
Source: Shell interpretation of ICE, CME, S&P Global Platts 2020 and 2021 data

2020 started with a well-supplied global gas and LNG market

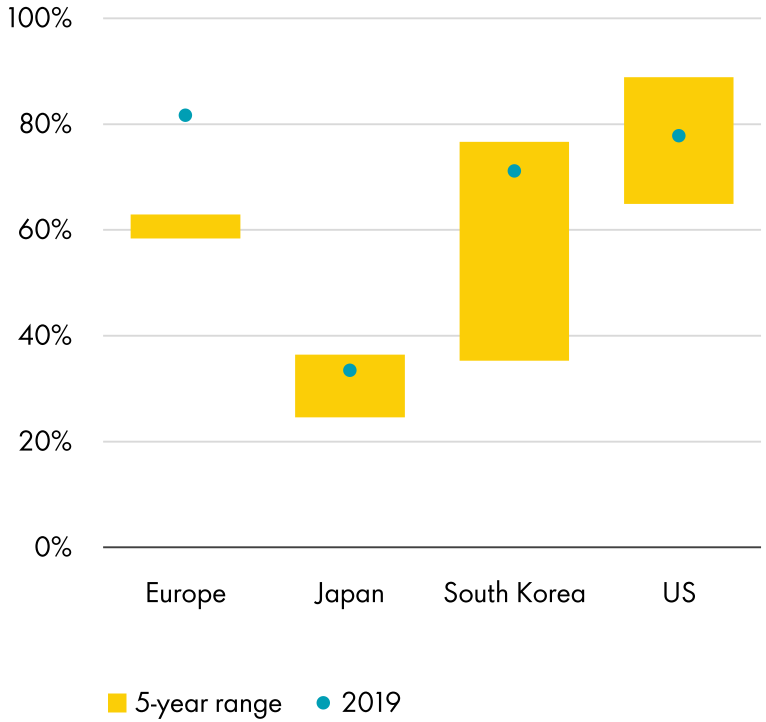
LNG liquefaction capacity additions
MT



Winter* average temperature
Degrees Celsius



Gas/LNG storage level**
% utilisation



Source: Shell interpretation of IHS Markit, PIRA, AGSI, METI, KESIS and EIA 2020 data

*Winter months are from October through March. 2020 winter average from October 2019 to March 2020

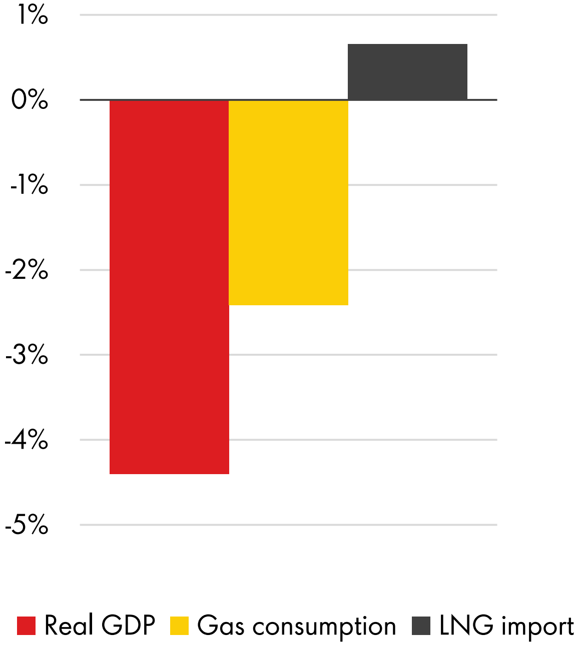
**As of 31st December 2019

LNG demand continued to grow despite a global pandemic

China and India lead demand recovery

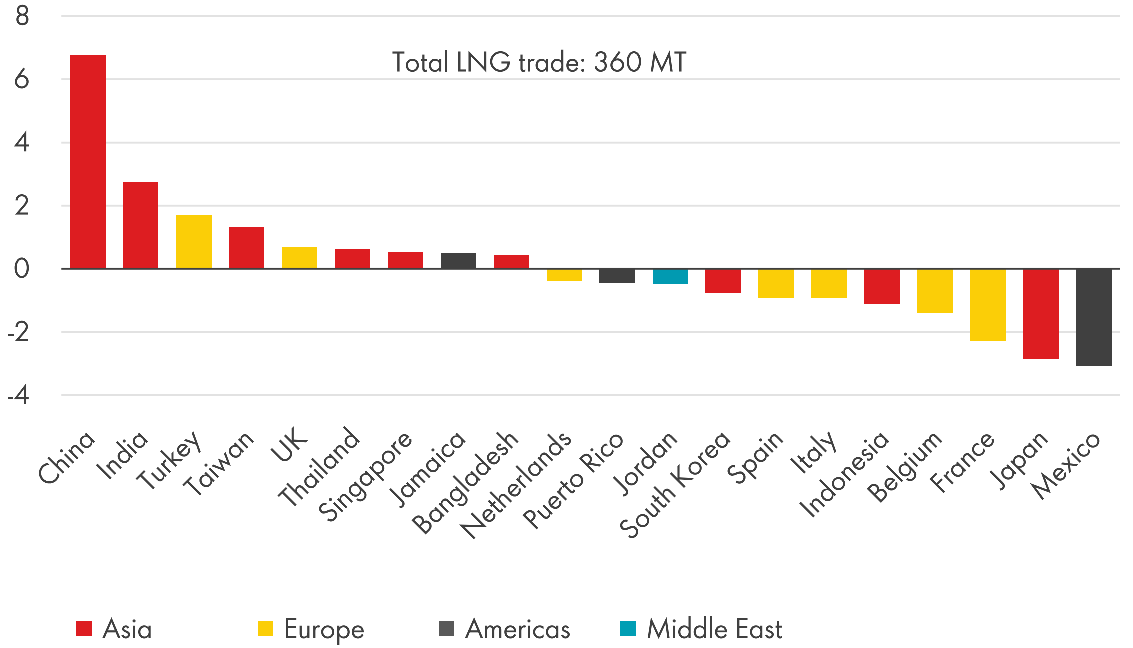
GDP, gas & LNG growth in 2020

%



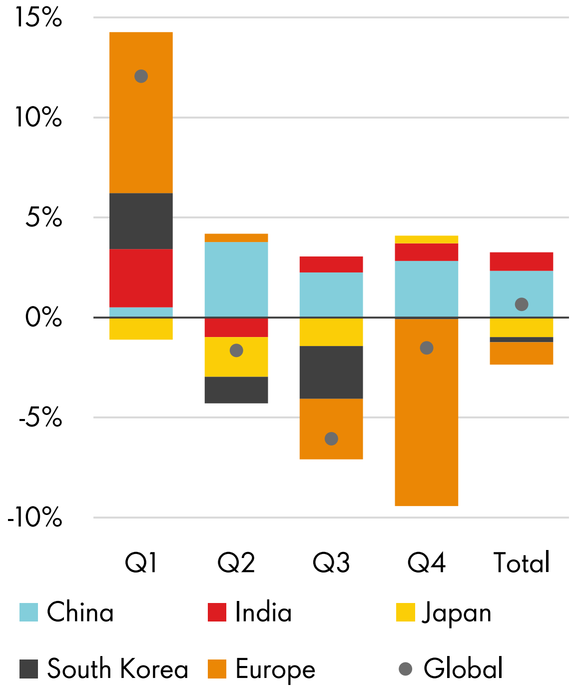
Net LNG imports: 2020 y-o-y

MT



2020 share of demand growth by region

%



Source: Shell interpretation of IHS Markit, customs, Kpler and International Monetary Fund 2020 data

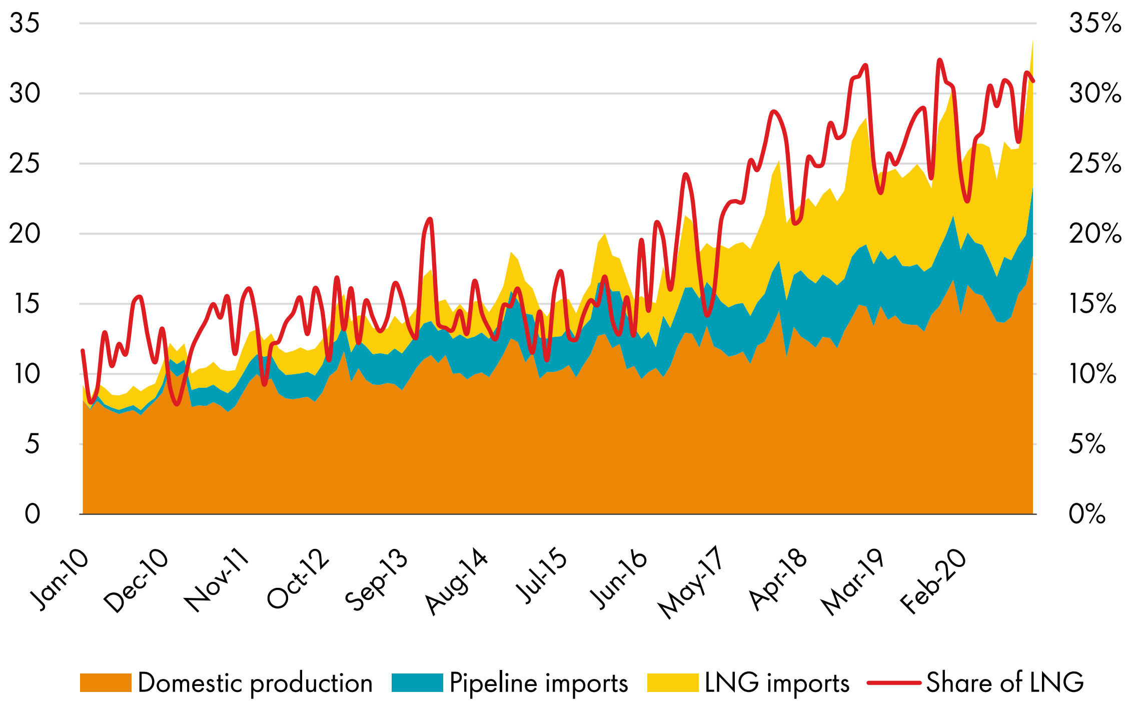
LNG importers with minimal year-on-year change are not included in this chart

China gas demand growth remained resilient in 2020

Record Chinese LNG imports in December 2020

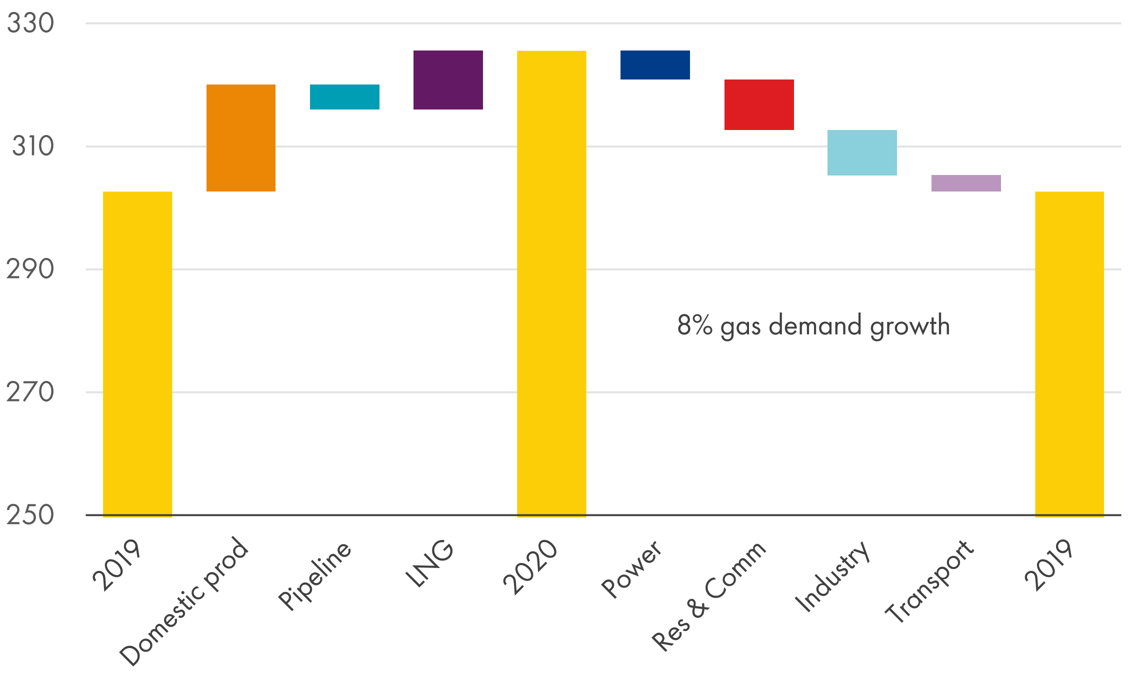
China domestic gas production & LNG demand

BCM



China gas supply & demand

BCM



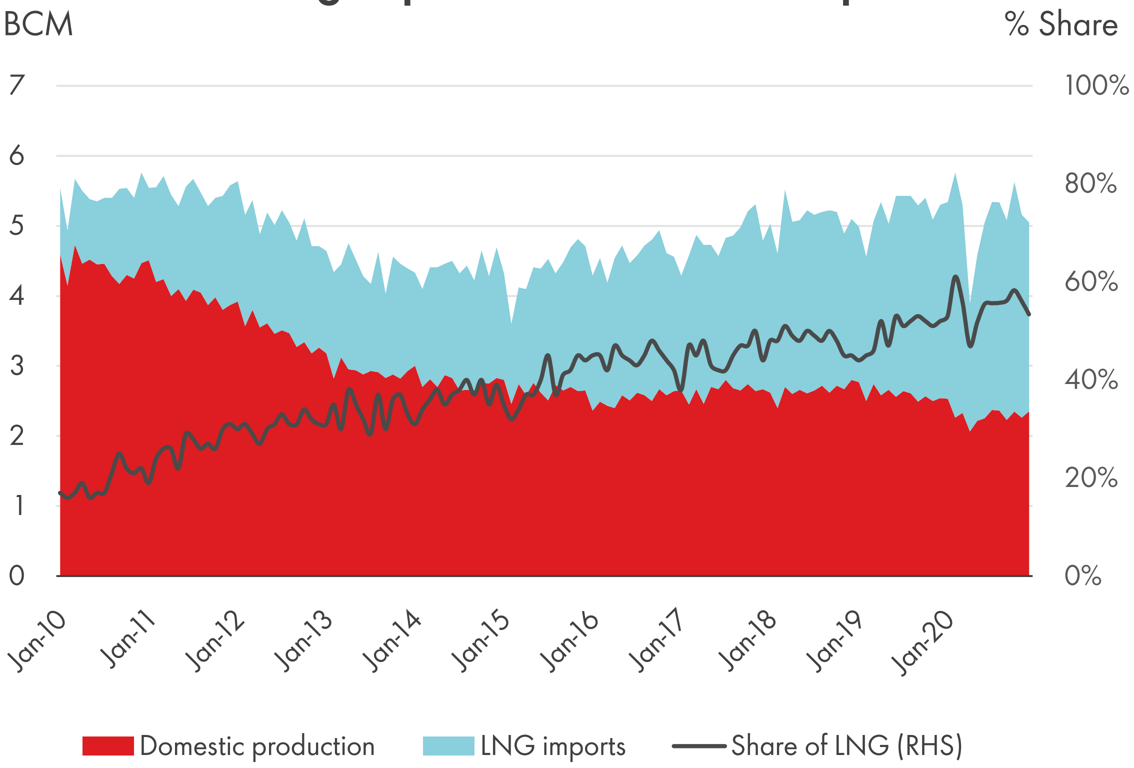
Source: Shell interpretation of IHS Markit and Chinese customs 2020 data

Res & Comm: Residential and commercial Domestic Prod: Domestic Production

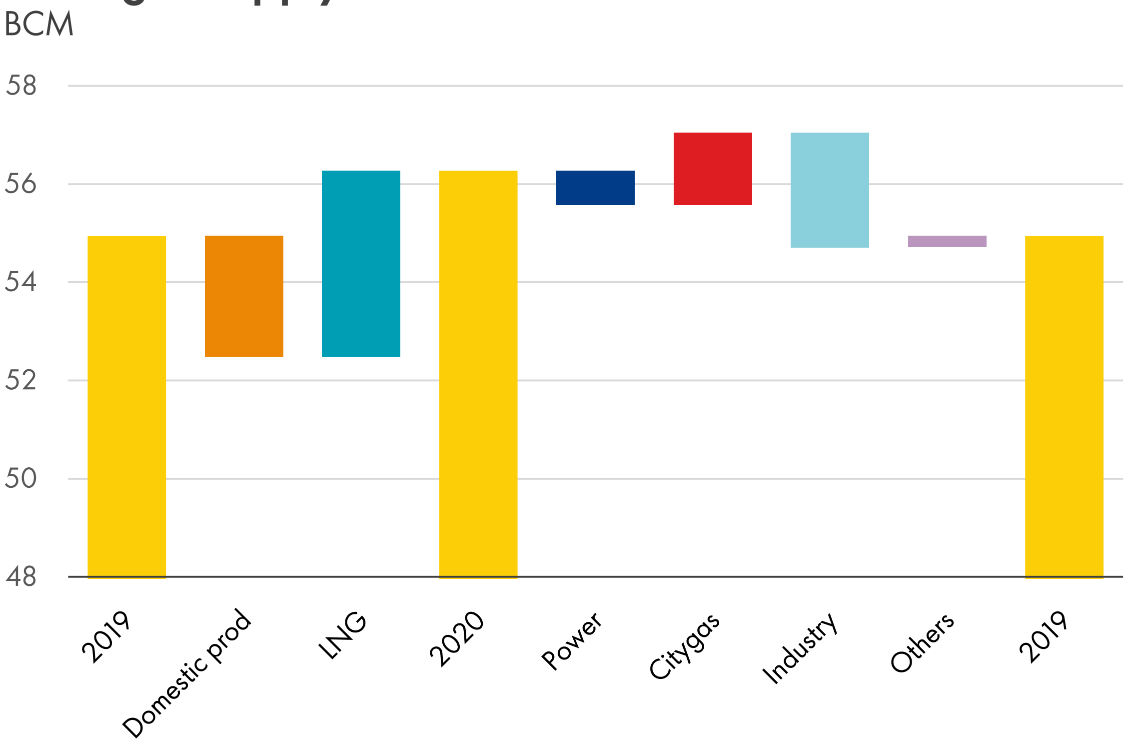
Lower-priced LNG results in 11% increase in Indian imports

LNG supplements reduced domestic gas production

India domestic gas production & LNG imports



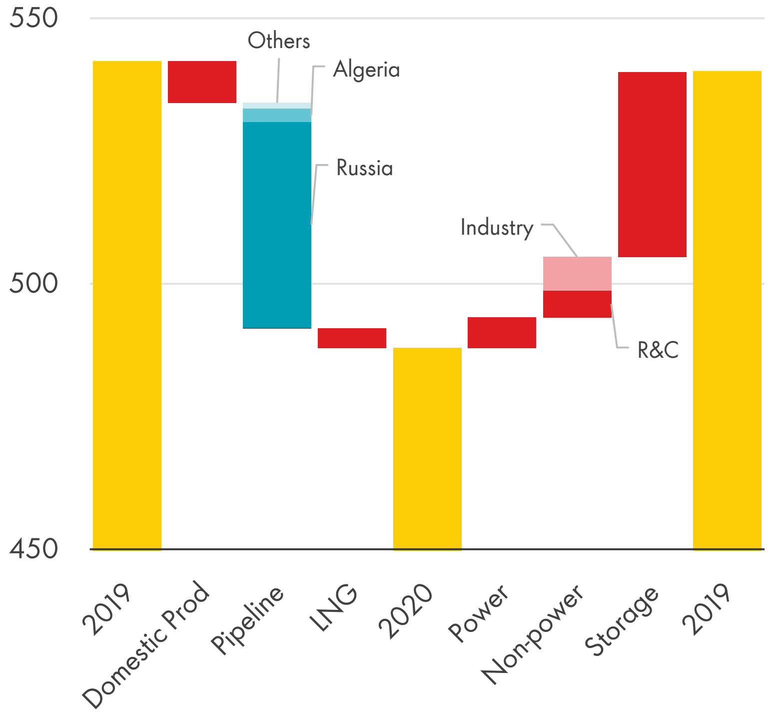
India gas supply & demand



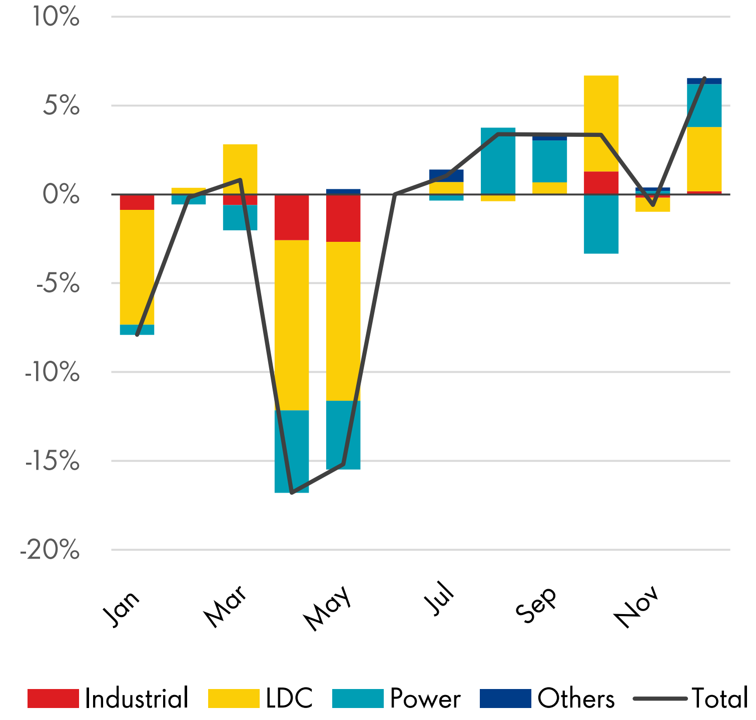
Sources: Shell interpretation of Petroleum Planning and Analysis Cell (PPAC), Central Electricity Authority (CEA), IHS Markit and Kpler 2020 data

Flexibility in European gas supply sources helped with global LNG balance

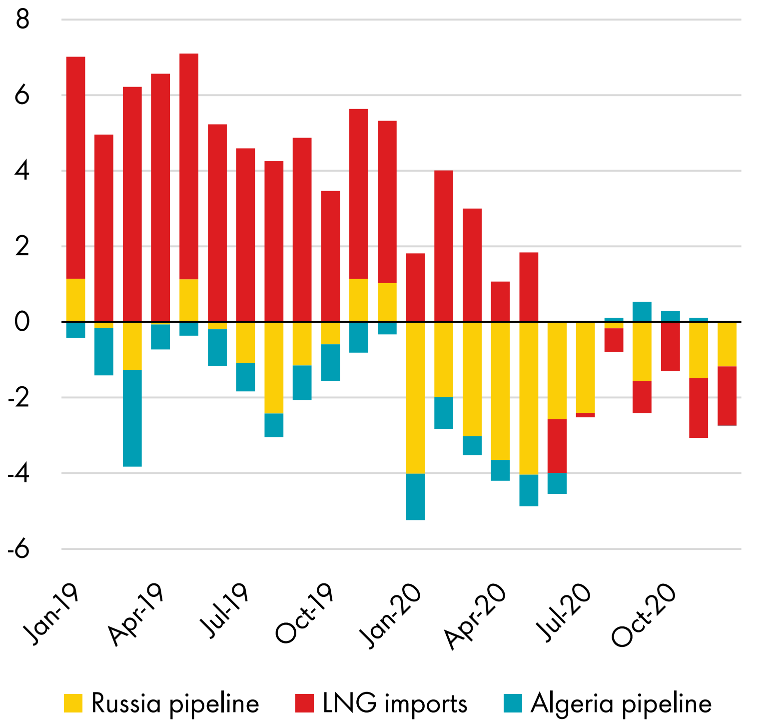
Europe gas supply & demand
BCM



Europe gas demand growth y-o-y
%



Europe gas & LNG import growth
BCM



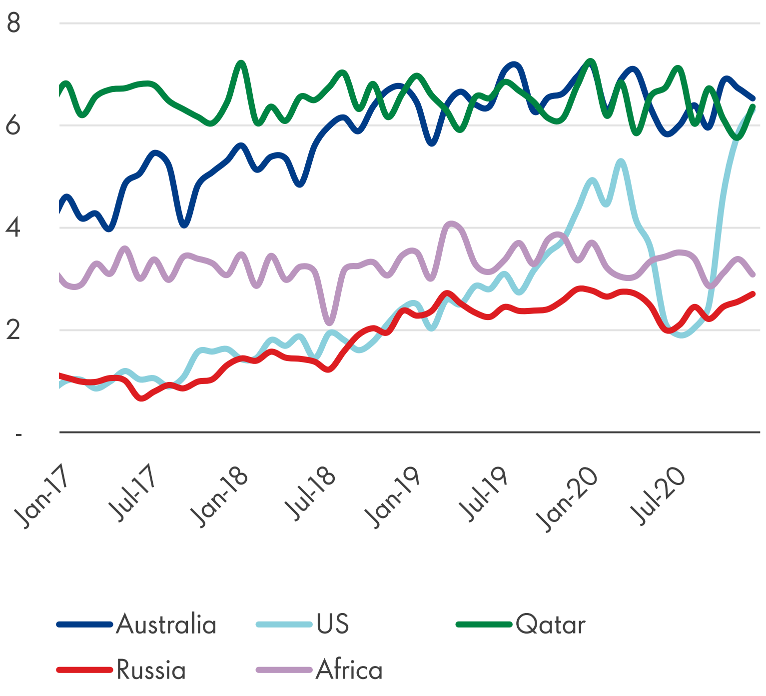
Source: Shell's interpretation of ENTSOG, Wood Mackenzie and European TSO 2020 data
LDC – Local distribution company   R&C: Residential and commercial

Supply response to changing market conditions

US supply added volume and flexibility

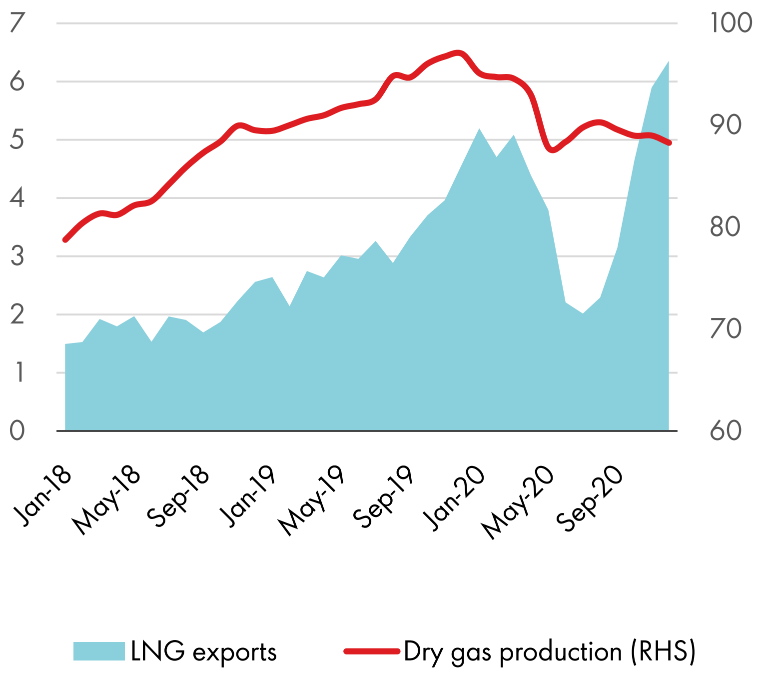
Major LNG exporters

MT



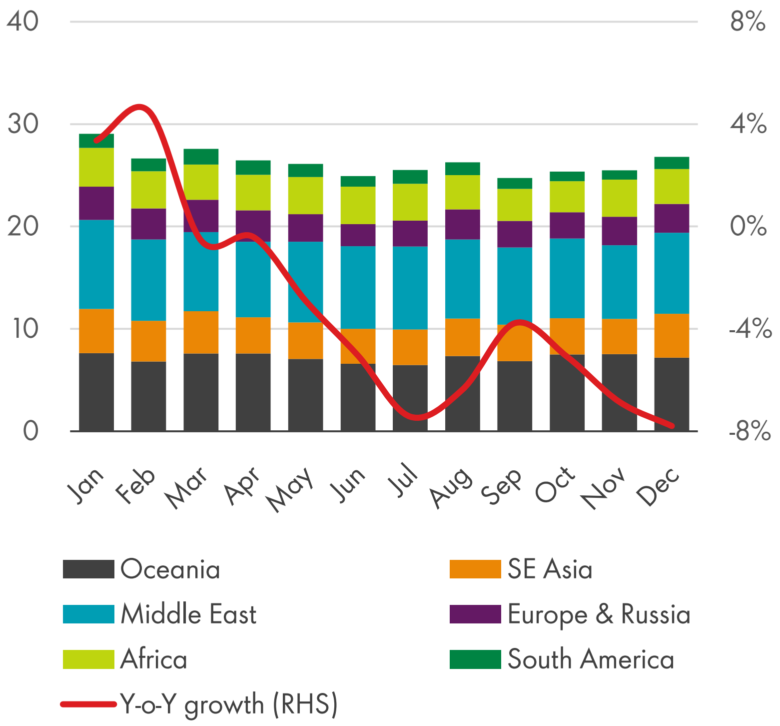
US LNG exports

MT Bcf/d



Non-US LNG supply

MT

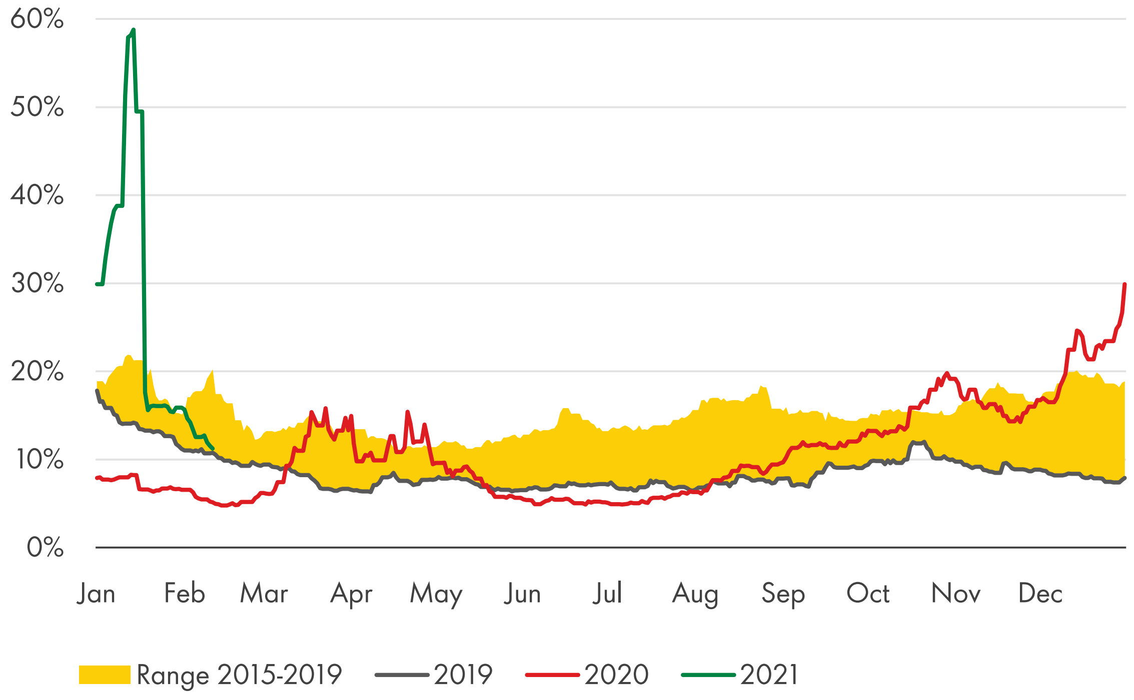


Source: Shell interpretation of Kpler, EIA and Wood Mackenzie 2020 data

Global LNG prices hit a record low before rebounding to hit a record high in January 2021

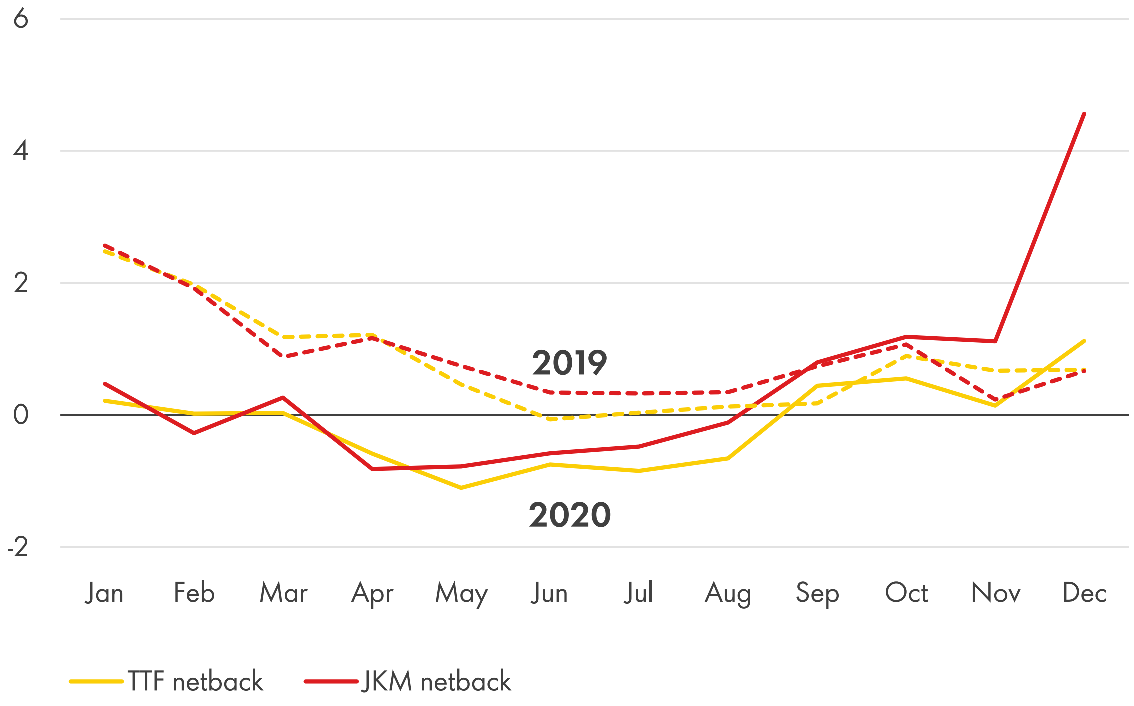
Asia spot price

JKM as % of Brent



US LNG export margins*

$/MMBTU

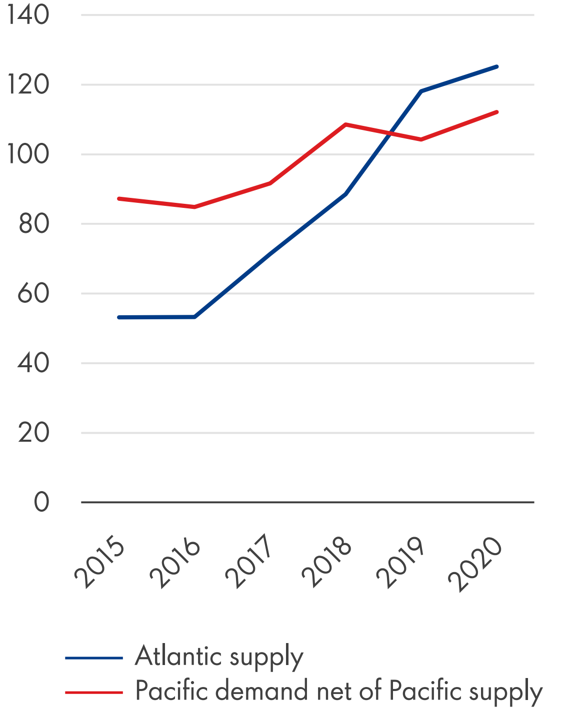


Source: Shell interpretation of ICE, CME, S&P Global Platts 2020 and 2021 data

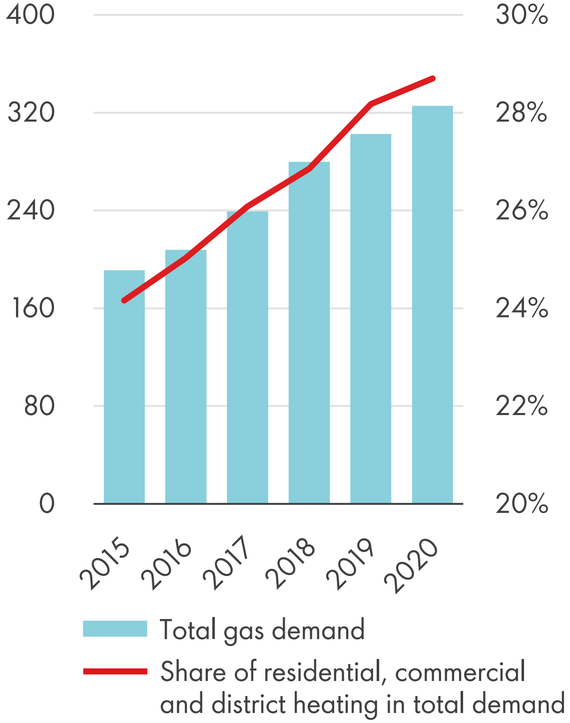
*Excludes liquefaction fee; netback calculated as: JKM and TTF minus regasification and transportation cost minus 115% Henry Hub

A combination of structural issues and singular events caused the price rally

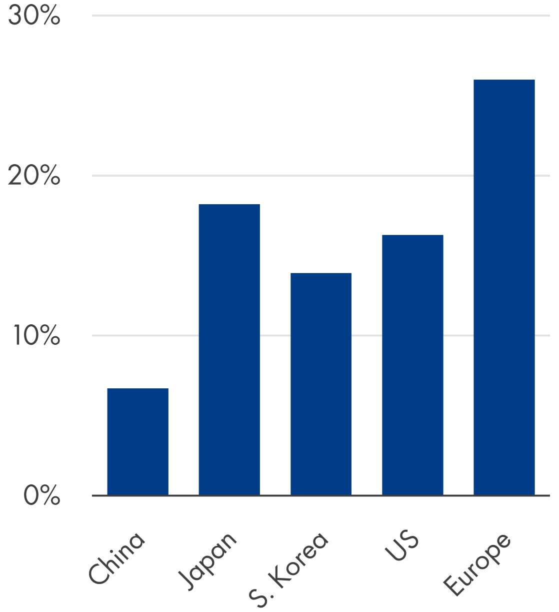
Regional supply & demand
MTPA



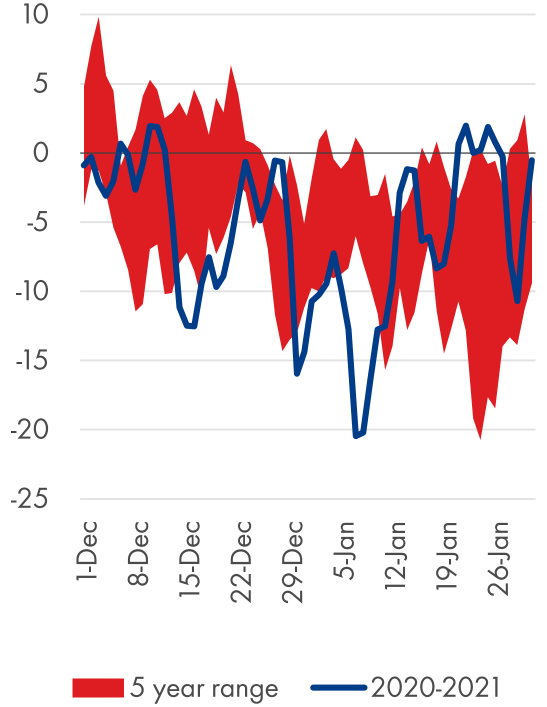
China heating demand
BCMA



Gas storage capacity
Share of storage in total gas demand



North Asia temperature
Degrees Celsius



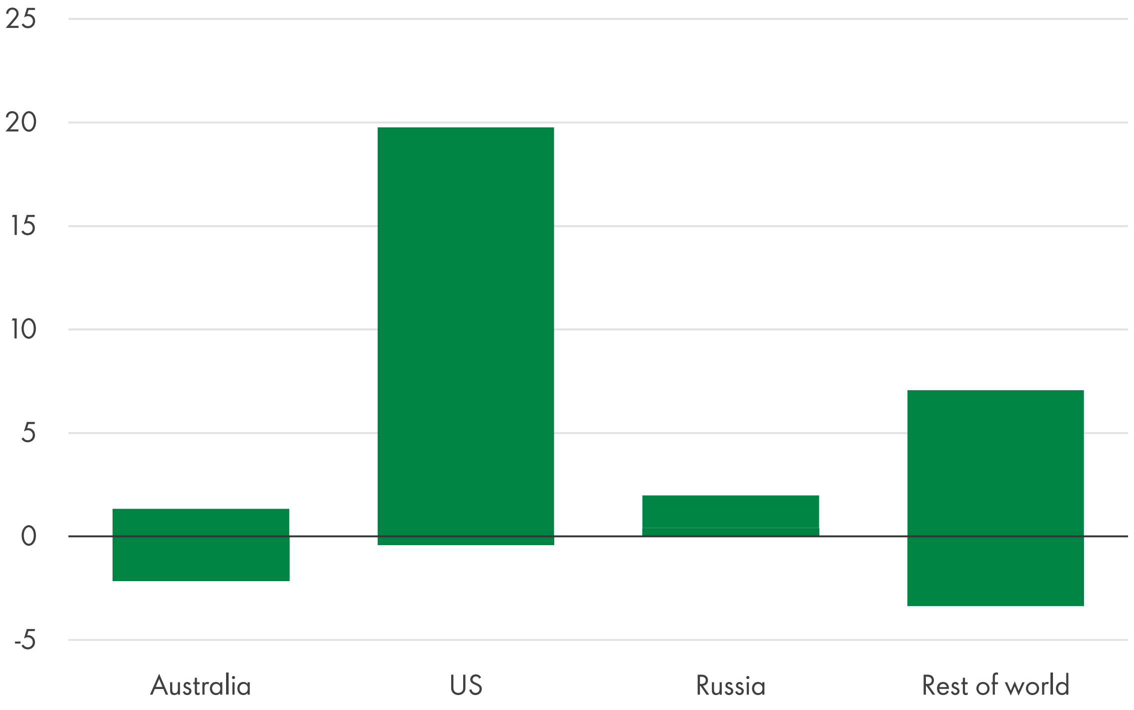
Source: Shell interpretation of IHS Markit, Wood Mackenzie and S&P Global Platts 2020 and 2021 data

Asian LNG demand recovery projected to continue in 2021

LNG exports from the US expected to offer flexible supply

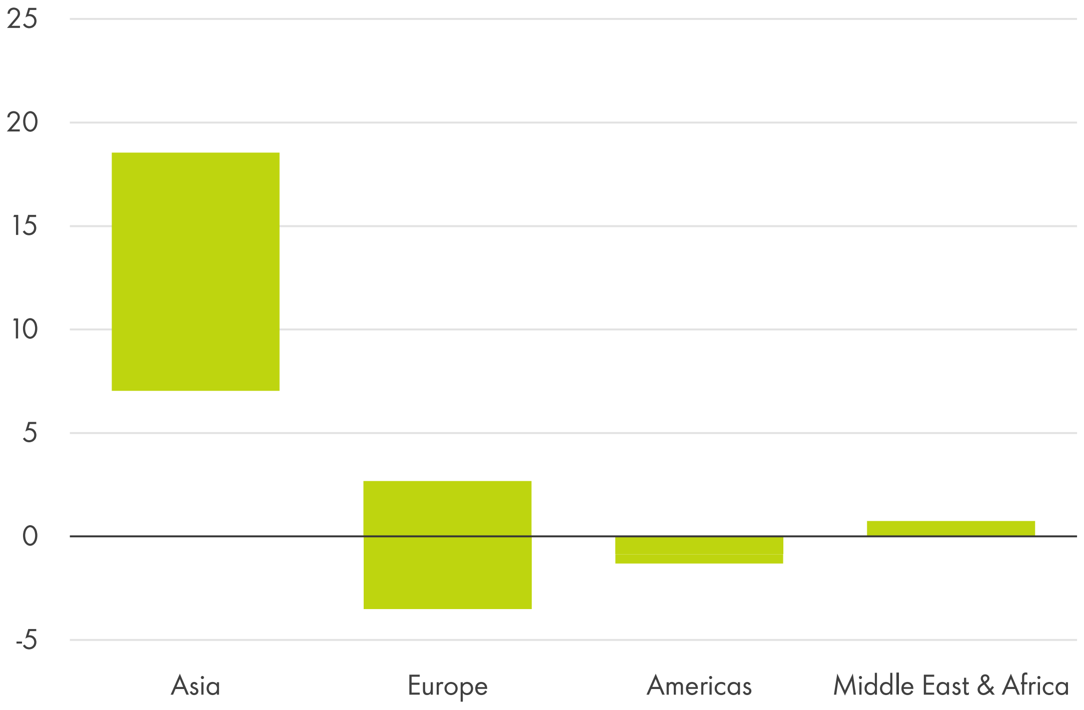
LNG supply growth range by country

MTPA



LNG demand growth range by region

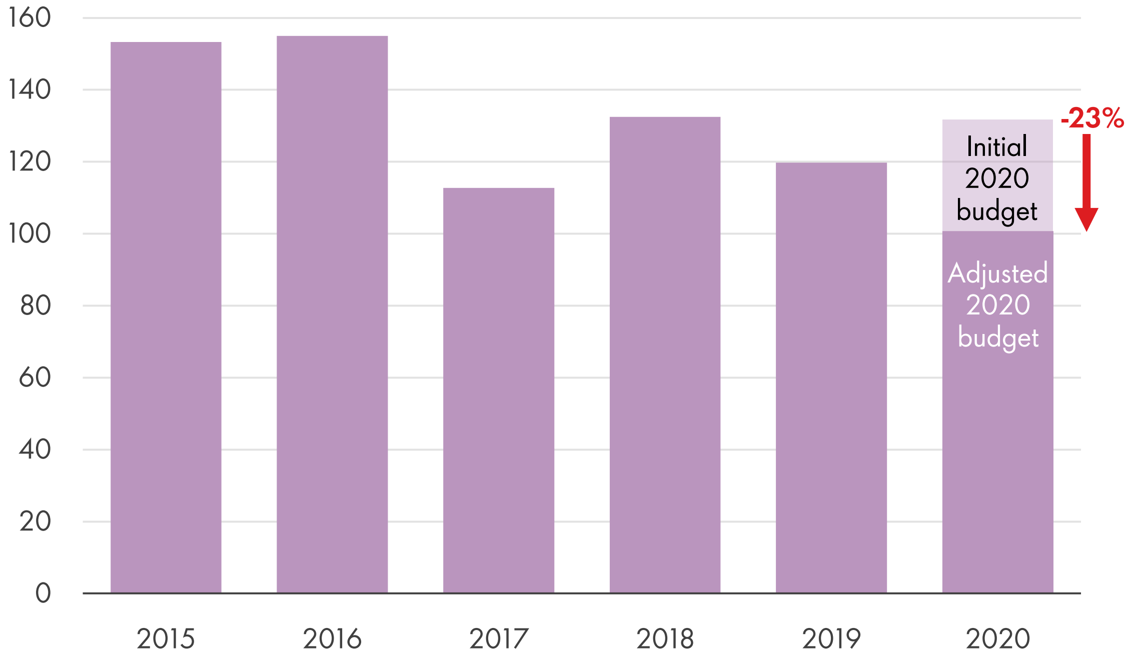
MTPA



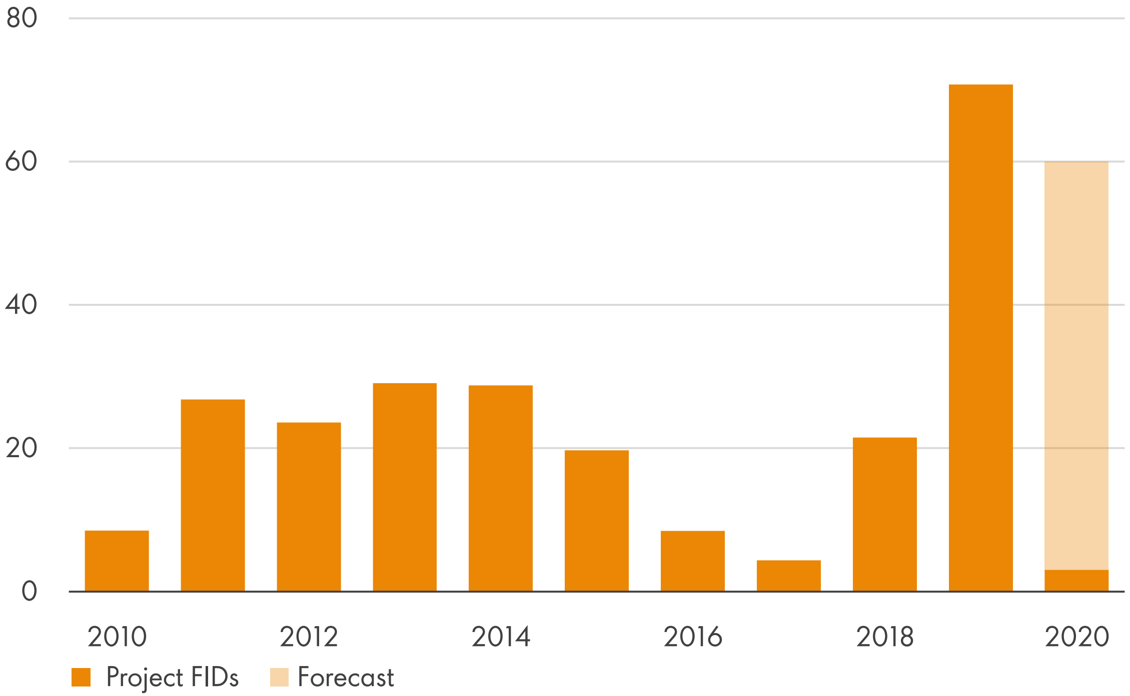
Source: Shell interpretation of IHS Markit and Wood Mackenzie 2020 data

LNG supply investment halts due to pandemic-related economic crisis

Oil & gas industry* capex spend
$billion



Investment in liquefaction capacity
MTPA



Source: Shell interpretation of IHS Markit and Wood Mackenzie 2020 data

*Industry represents estimated capital budgets of ExxonMobil, Shell, Chevron, Total, BP, Equinor and Eni, as calculated by Wood Mackenzie

03

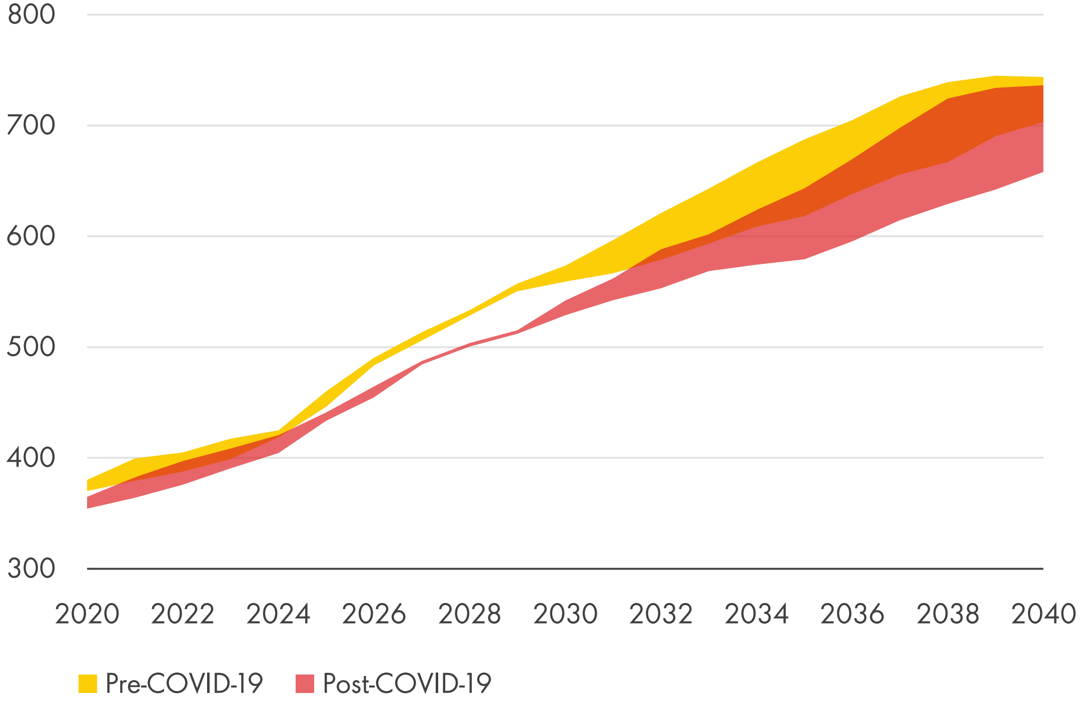
Complementary spot and term contract structures and cleaner pathways to drive LNG growth

COVID-19 pandemic delays project construction timelines

Lasting impact expected on LNG supply not demand

Global LNG supply forecast

MTPA



EU LNG import forecast change

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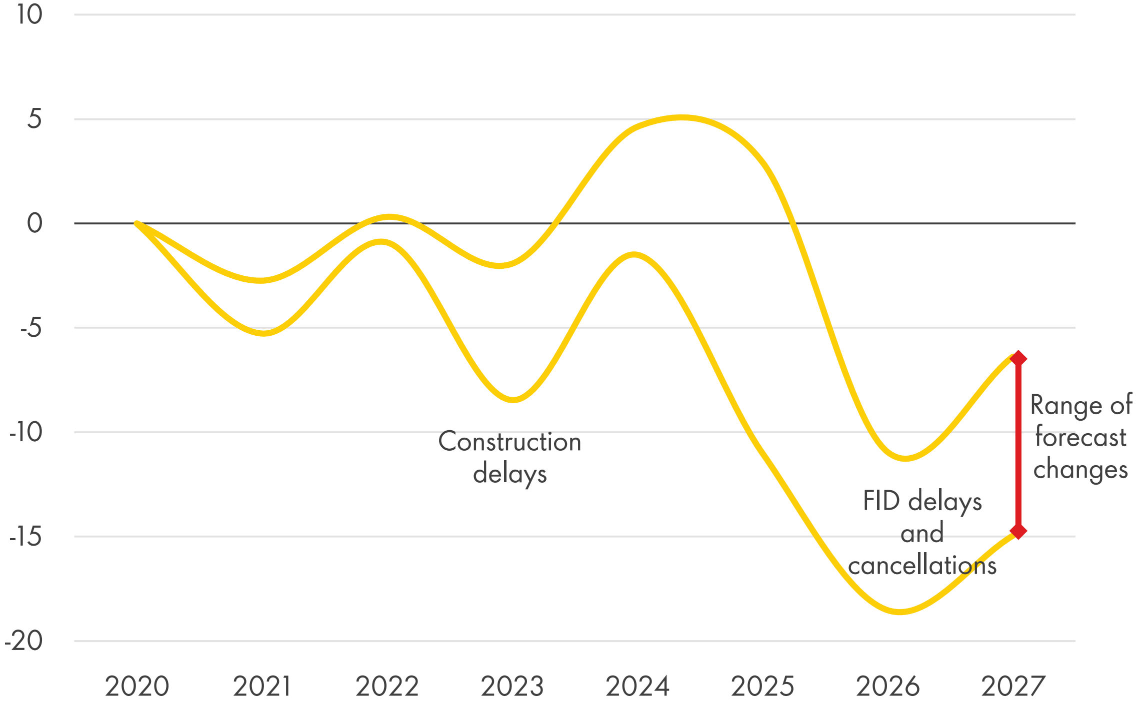
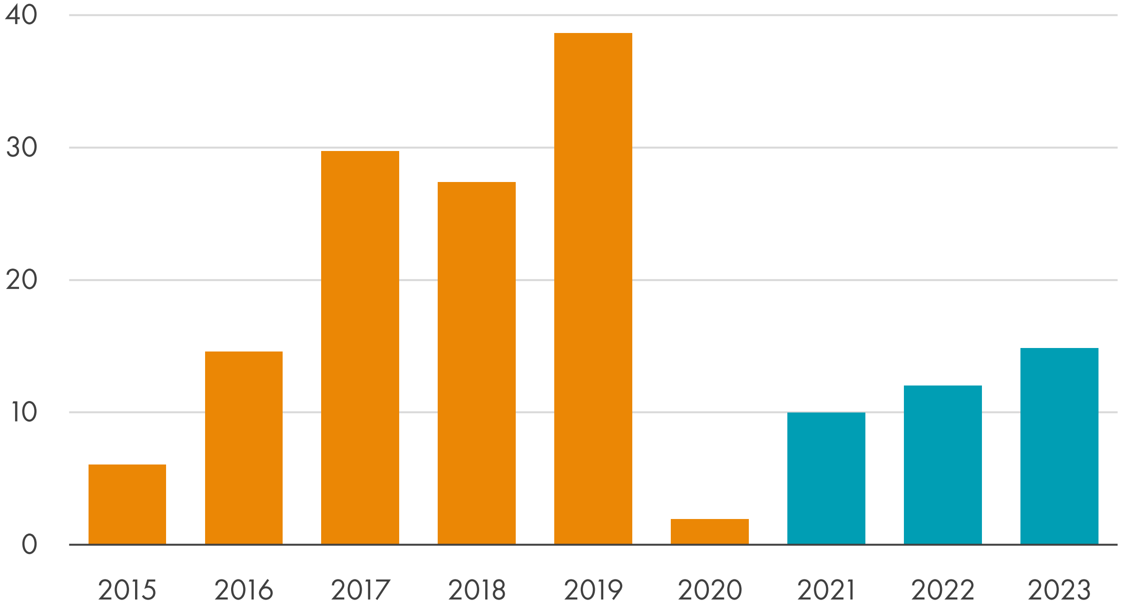


Source: Shell interpretation of Wood Mackenzie and IHS Markit 2020 data

Supply-demand gap estimated to emerge in the middle of the current decade as demand rebounds

LNG trade volume growth

MTPA



Emerging LNG supply-demand gap

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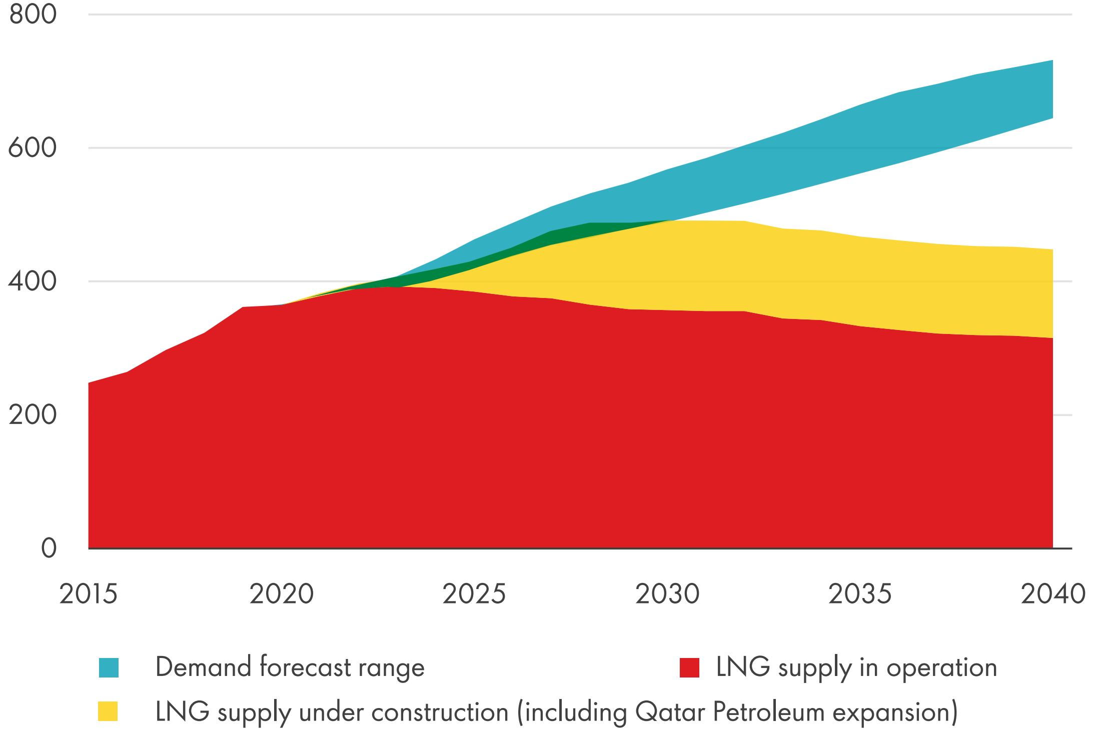


Source: Shell interpretation of IHS Markit, Wood Mackenzie, FGE and Poten & Partners 2020 and 2021 data
Qatar Petroleum LNG expansion announced in February 2021

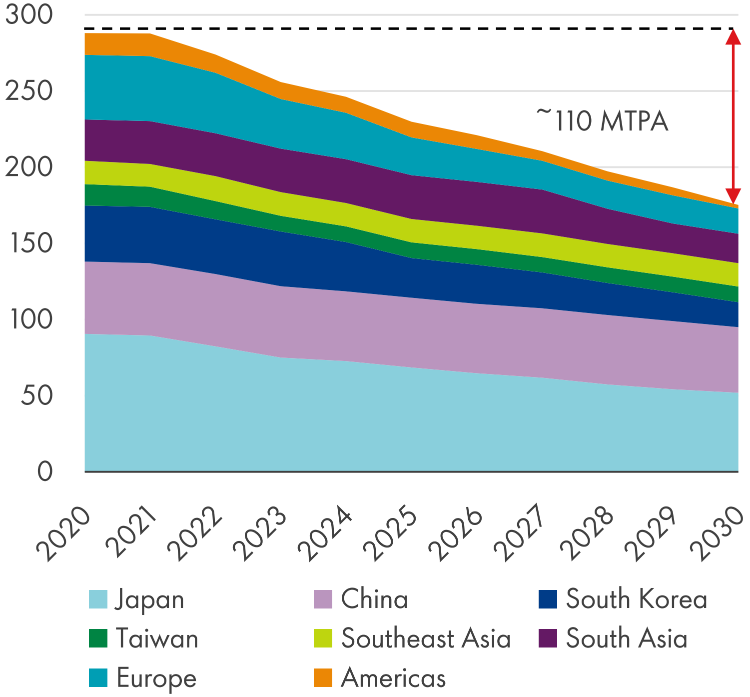
Triggers exist for change in the global LNG market

Shell
LNG Outlook 2021

More market participants with increasingly diverse needs

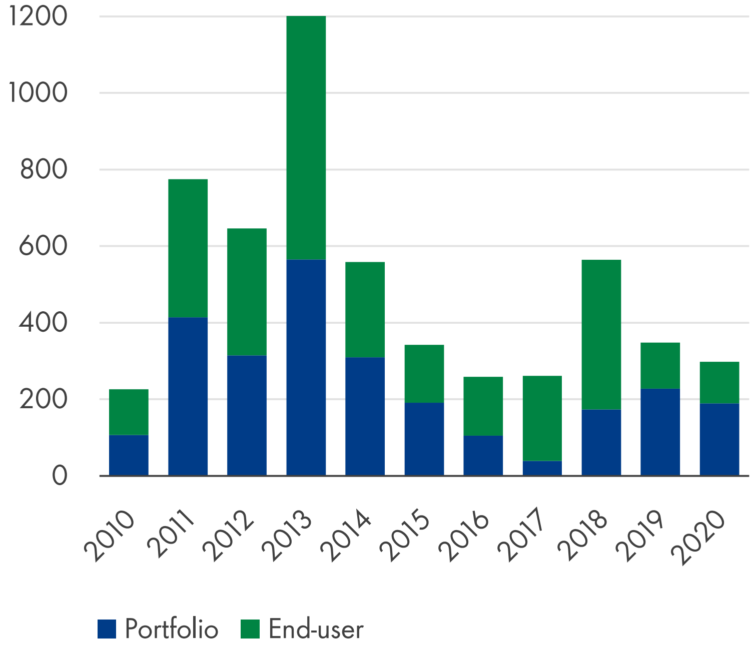
Long-term LNG contract expiries

MTPA



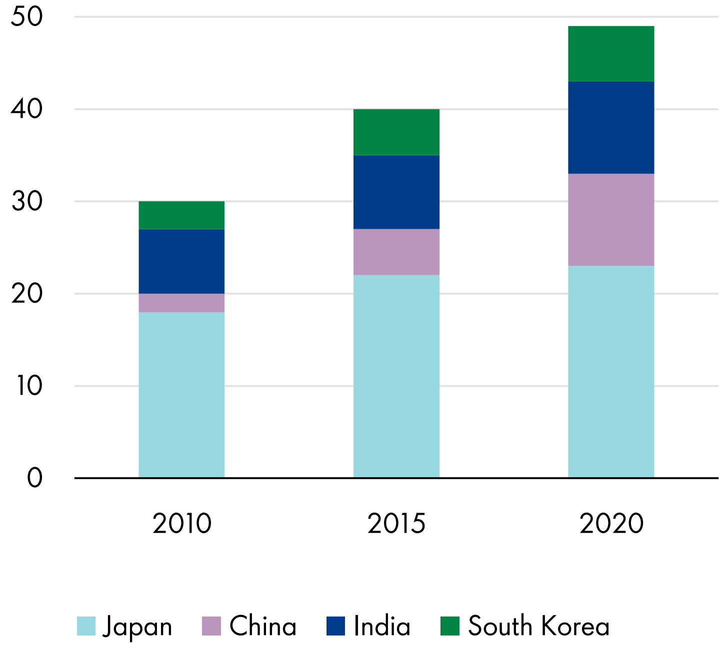
Total LNG contract volumes by buyer type

MT



LNG importers

of regasification capacity holders in Japan, China, India and South Korea



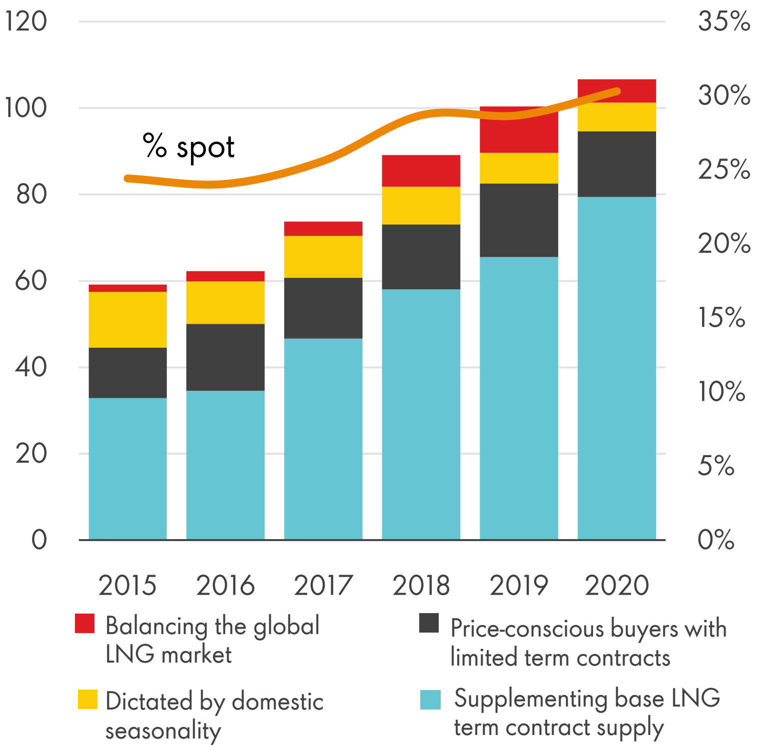
Source: Shell interpretation of IHS Markit 2020 data

Current industry structure appears sustainable

No acceleration in the move to commoditisation

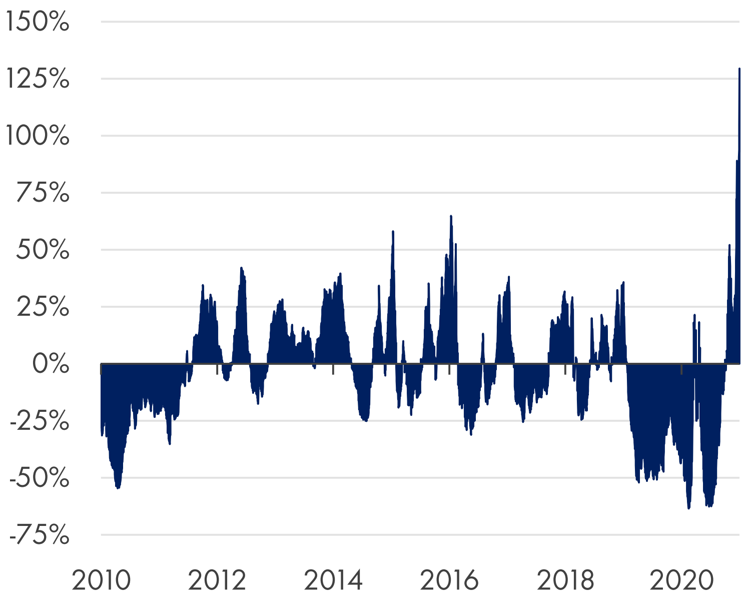
Spot LNG deliveries

MT | % of total market



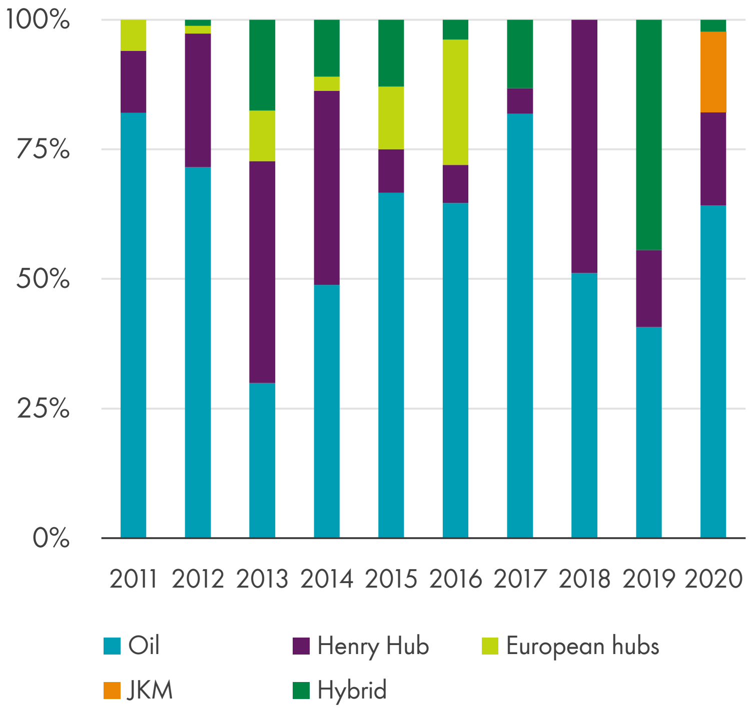
Spot deviation from term

% change from term price



Term contract indexation

% of total



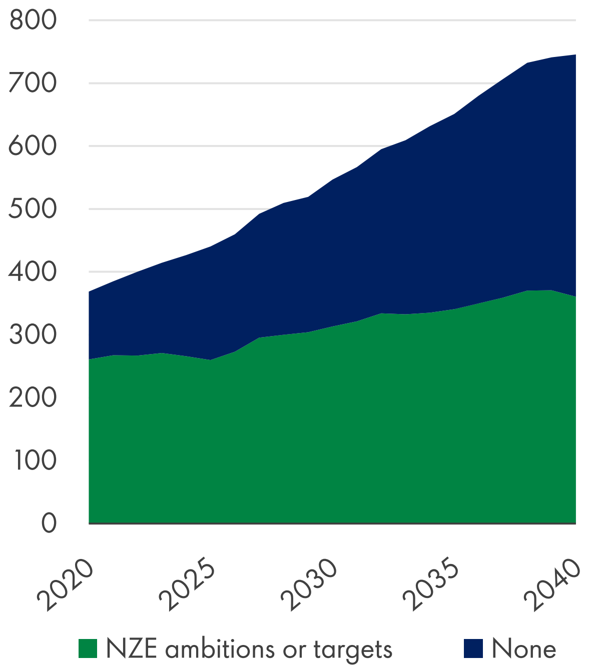
Shell interpretation of IHS Markit, Wood Mackenzie, ICE, CME and S&P Platts 2020 and 2021 data

NZE targets will need cleaner and innovative solutions

All levers needed to decarbonise LNG

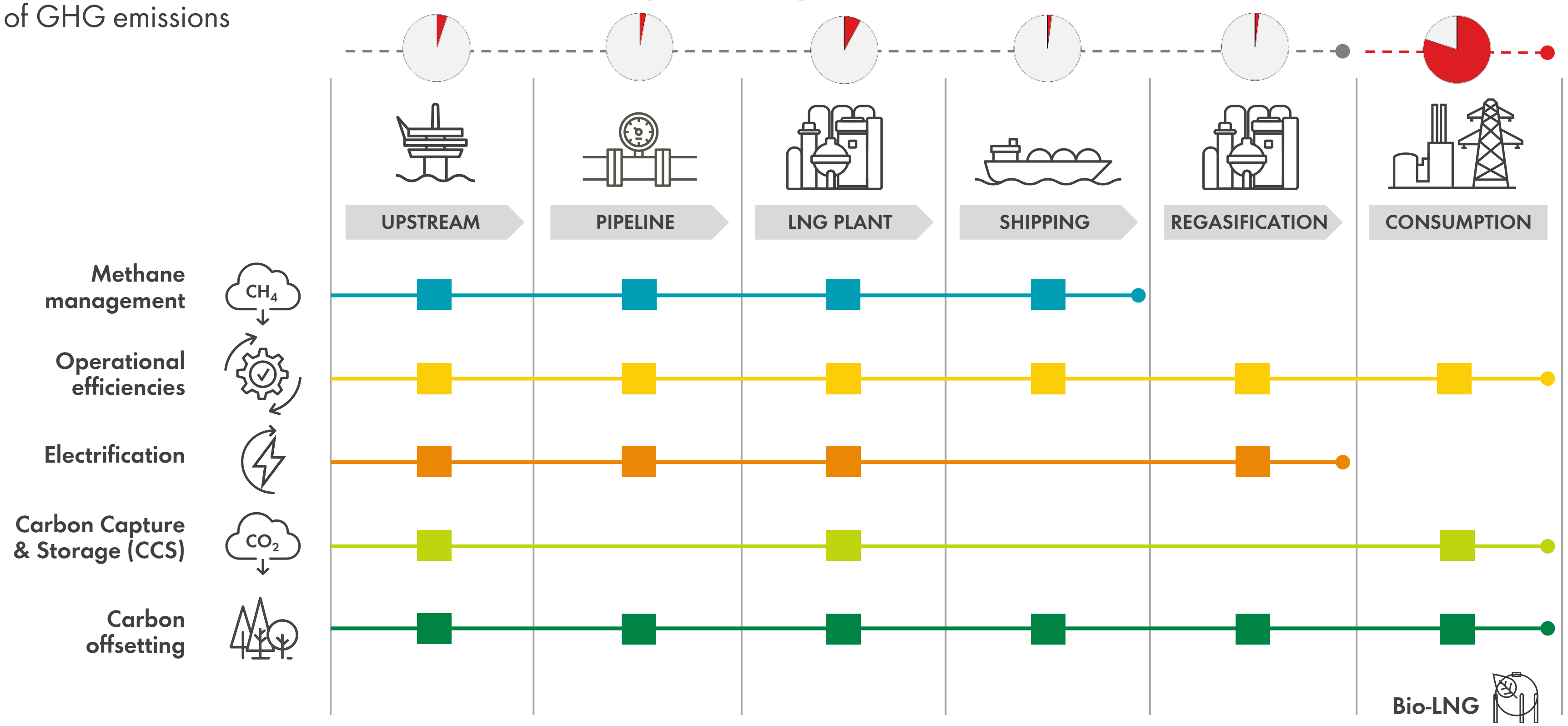
LNG demand forecast by net-zero emissions pledge

MTPA



LNG value chain emissions and mitigation options

% of GHG emissions



Source: Shell interpretation of IHS Markit, Wood Mackenzie and IEA 2020 data

Summary

Gas and LNG have a key role to play in a decarbonising world

- Net-zero emissions announcements across the globe
- Gas and LNG can play a key role in decarbonising hard-to-electrify sectors
- Nearly half of gas demand growth in the next 20 years expected to come from Asia

LNG shows its resilience and flexibility in 2020

- LNG demand continued to grow despite the global pandemic and ensuing economic crisis
- Global LNG prices hit a record low before rebounding to hit a record high in January 2021
- New LNG supply investment decisions ground to a halt

Complementary spot and term contract structures and cleaner pathways to drive LNG growth

- Supply-demand gap estimated to emerge in the middle of the current decade
- Current industry structure supports the changing needs of buyers
- Net-zero emissions targets will need cleaner and innovative energy solutions

NATURAL GAS

PROVIDING MORE AND CLEANER ENERGY

CONTENTS

NATURAL GAS
PROVIDING MORE AND CLEANER ENERGY

ONE IN EVERY SIX PEOPLE ON THE PLANET LIVES WITHOUT ACCESS TO ELECTRICITY, ACCORDING TO THE WORLD BANK

NATURAL GAS | PROVIDING MORE AND CLEANER ENERGY

FOREWORD FROM THE CEO

Ben van Beurden,
CEO,
Royal Dutch Shell plc

Meeting growing global demand for energy, while tackling climate change and pollution, is a fundamental challenge facing society.

It was the focus of two historic meetings convened by the United Nations in 2015. In New York, world leaders agreed on 17 Sustainable Development Goals. They range from eradicating hunger to ensuring clean water is available for everyone. The UN identified energy as a "crucial" common link for achieving these ambitious goals.

Later that year, in Paris, world leaders agreed to work towards limiting the global rise in temperature to well below 2°C above pre-industrial levels, to avoid the more serious effects of climate change.

Both the Sustainable Development Goals and the Paris Agreement have galvanised countries, companies and individuals to strengthen efforts to cut greenhouse gas emissions and improve air quality, while providing the energy that powers our lives. Even today, one in every six people in the world does not have access to electricity.

A transformation of the global energy system is needed. This will take place at different paces depending on a range of factors, from national policies to the technologies and products consumers choose.

Shell is playing its part in the energy transition – from reducing the carbon intensity of our oil and gas operations, to investing in low-carbon technologies, including carbon capture and storage, hydrogen, solar and wind power.

That is why I announced a net carbon footprint ambition, covering not just emissions from our own operations but also our customers' emissions from the products that we sell. We aim to cut the net carbon footprint of our energy products by around half by 2050, on a grams of CO_2 equivalent per megajoule consumed basis. As an interim step, by 2035, we aim to reduce it by around 20%. We will do this in step with society's drive to align with the Paris goals.

A major contribution we can make right now is to continue to expand the role of natural gas, which makes up half of our total production.

This publication explains why Shell believes gas is needed across the global economy – now and in the future.

NATURAL GAS | PROVIDING MORE AND CLEANER ENERGY

INTRODUCTION FROM SHELL'S INTEGRATED GAS AND NEW ENERGIES DIRECTOR: THE CRITICAL ROLE OF NATURAL GAS

Maarten Wetselaar,
Integrated Gas and New Energies Director, Royal Dutch Shell

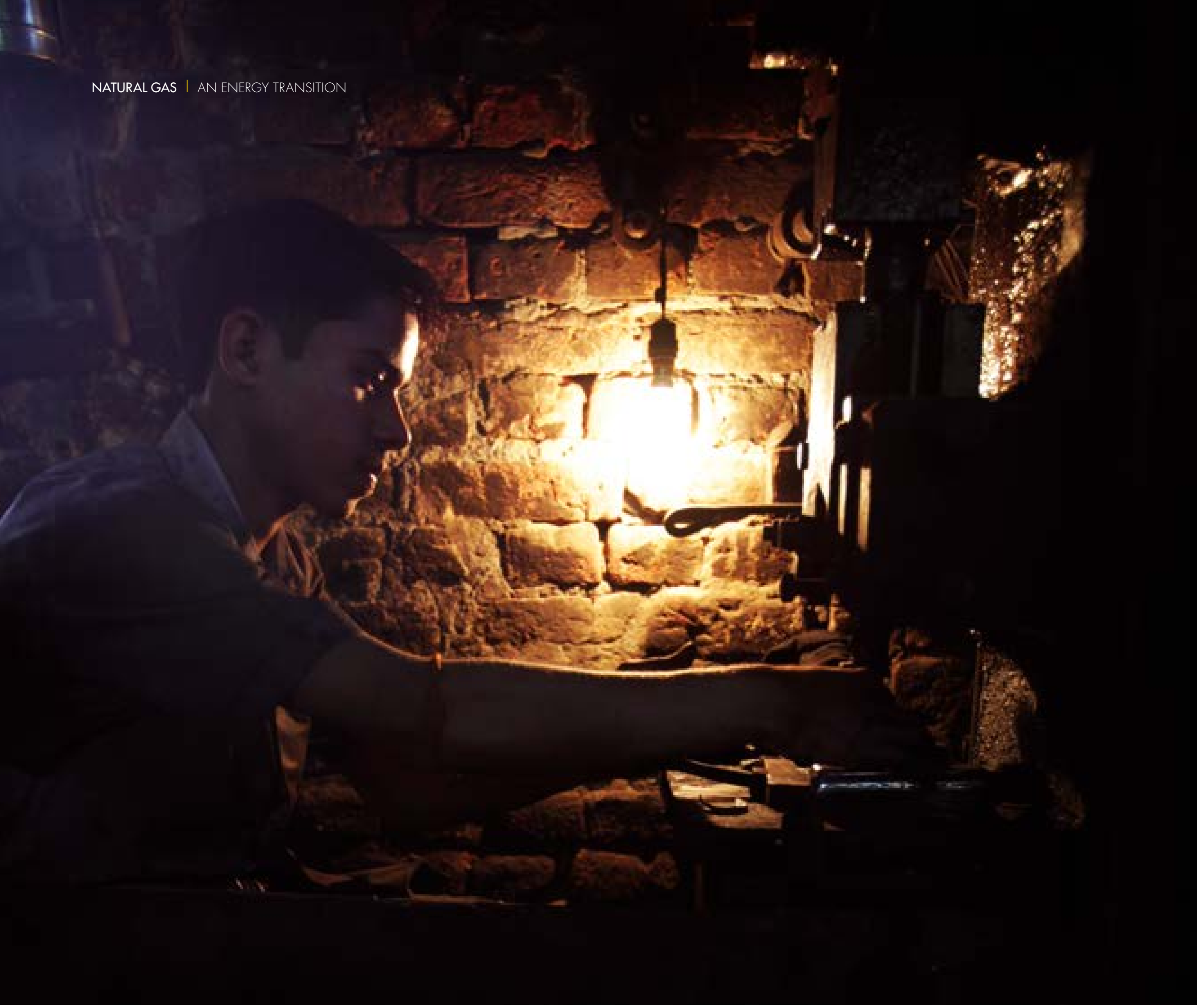
Natural gas helps provide more and cleaner energy around the world.

With the number of people on the planet expected to increase by a billion by 2030, gas is one of the few energy sources that can meet growing demand while reducing emissions from electricity generation, industry, the built environment and transport.

Using natural gas is already helping to reduce carbon dioxide and improve air quality where it replaces coal or diesel. This has been seen in electricity generation from the UK to the USA, as well as in countries like China, where increased use of natural gas is helping to reduce air pollution in power and industry.

Gas also supports an increasing role for renewables. It provides critical support for wind, solar and hydroelectricity, helping to match the supply and demand of cleaner electricity. This will be important as the use of electricity expands.

Gas will also continue to play a critical role in sectors where demand is anticipated to grow, but which are more difficult to electrify, such as the production of steel, cement and chemicals, as well as long-distance transportation of people and goods.



CHAPTER 1: **AN ENERGY TRANSITION**

1

NATURAL GAS | AN ENERGY TRANSITION

Powering progress

Energy benefits most people throughout their lives. Today, more than ever, our livelihoods, wellbeing and communities depend on reliable sources of energy. Energy lights, heats and cools homes and businesses. It transports and connects people and goods all over the world. It enables better water and sanitation systems and improvements in healthcare and education. It is used to make steel, cement, chemicals and other building blocks for the world's growing cities.

The United Nations (UN) has described energy as "central to nearly every major challenge and opportunity the world faces today. Be it for jobs, security, climate change, food production or increasing incomes, access to energy for all is essential."

Yet, even today, little or no access to energy deprives part of the world's population of the opportunity to improve their quality of life. Around 1.1 billion people continue to live without electricity; more than three times the population of the USA. A further billion people struggle with unreliable supplies of electricity.

Growing global demand for energy

The world will need more energy as populations grow. By 2070, the global population could reach 10 billion. That is 2.5 billion more people than today, which is equivalent to the combined populations of China and India, the two most populous countries in the world.

An increase in energy demand will also be driven by economic growth, and as people seek to improve their quality of life. That could mean lighting a home at night, running a refrigerator to store food or medicines, growing a business, or fuelling a car. Even assuming significant future energy efficiency gains, global energy demand is expected to grow by 30% between 2015 and 2040, according to the International Energy Agency (IEA) New Policies Scenario.

Reflecting economic growth, increases in future energy demand are likely to be concentrated in China, India, Africa, the Middle East and South-East Asia. In Asia, energy demand is expected to increase by 50% by the middle of the century, as the number of people in the region grows by 900 million. Demand for energy will also increase significantly in Africa.

NATURAL GAS HAS A CENTRAL ROLE IN THE ENERGY TRANSITION, PROVIDING MORE AND CLEANER ENERGY

How large could the energy system grow?

As we consider the future development of economies, and assume significant energy improvements, we estimate that an average of about **100 gigajoules of primary energy per person** is approximately what is required to fuel the energy-based services that support the decent quality of life to which people naturally aspire.

2015

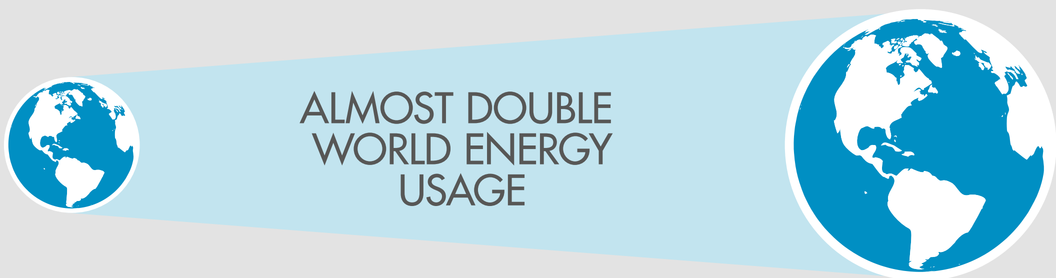
7+bn **WORLD POPULATION**

~570 **EXAJOULES** ENERGY CONSUMPTION PER YEAR

2070

10bn **WORLD POPULATION**

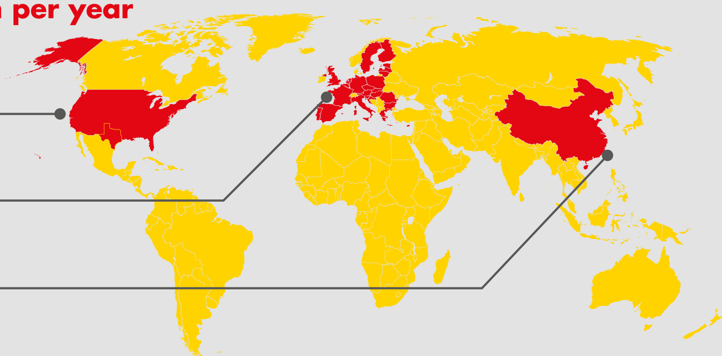
~1000 **EXAJOULES** ENERGY CONSUMPTION PER YEAR



Average current primary energy use*

Gigajoules per person per year

300
150
100



* **Source:** Shell analysis

Urbanisation

Today, cities consume about three-quarters of global primary energy and emit more than half of the world's total greenhouse gases, according to the UN. Around two thirds of the world's population are expected to live in cities by 2050, up from around half today. This reflects population growth and migration trends. It will require building the equivalent of a new city of more than 1 million people every week for the next three decades.

The greatest growth is expected in China, India, the USA and Sub-Saharan Africa. In China, around 1 billion people are expected to live in cities by the middle of the century – 350 million more than today and the equivalent of 40 new cities, each the size of Greater London. In India alone, more than 300 million people are expected to move to cities over the next 25 years. The use of energy and other resources such as water will increase considerably, as increased productivity, economic development and rising incomes drive up demand.

Providing more and cleaner energy

Providing access to energy, while minimising negative impacts on the planet and the air we breathe, is one of the greatest challenges of the 21st century. In 2015, the UN adopted 17 Sustainable Development Goals. These goals seek to tackle some of the world's greatest challenges by 2030. Goal 7 aims to "ensure access to affordable, reliable, sustainable and modern energy for all". This is an ambition that implies changes in the way energy is produced, accessed and used.

The challenge of climate change

Since the start of the Industrial Revolution, human activities have significantly raised the concentration of greenhouse gases in the atmosphere; mainly carbon dioxide (CO_2), methane and nitrous oxide. In 2014, the 5th Assessment Report of the UN Intergovernmental Panel on Climate Change (IPCC) concluded that it is "extremely likely that human influence has been the dominant cause of the observed warming since the mid-20th century".

At a landmark UN climate conference in Paris in 2015, world leaders agreed to work towards limiting the global rise in temperature to well below 2°C above pre-industrial levels to avoid the more serious effects of climate change, including floods, droughts and sea-level rises. The world is already around halfway to that 2°C limit.

Today, energy is responsible for two-thirds of global greenhouse gas emissions. Oil (32%), natural gas (21%) and coal (29%) together make up 82% of the world's energy mix, according to the IEA.

The remaining fifth comes from biomass (including wood, peat and dung), waste, nuclear, hydropower, and other renewables (such as solar and wind). More energy from the current mix means more greenhouse gases, which leads to further climate change.

The world currently emits 32 billion tonnes of energy-related CO_2 each year. To limit the rise in global temperature to 2°C, the IEA has calculated that energy related CO_2 emissions need to fall to around 18 billion tonnes a year by 2040.

This poses a significant challenge. To put it in context, removing around 200 million cars from the road (equal to every car in Europe) would save just 1 billion tonnes each year.

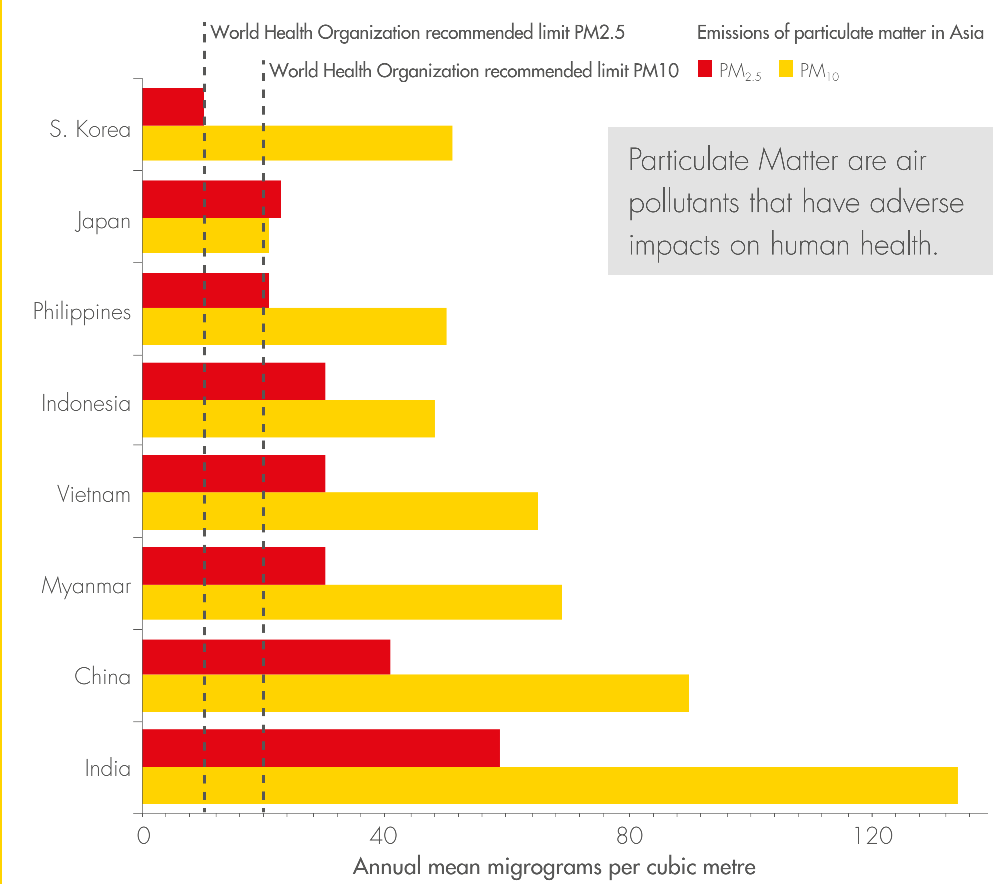
NATURAL GAS | AN ENERGY TRANSITION

Improving air quality

Today's energy mix also has a significant impact on air quality, particularly in densely populated urban areas. In the energy system, most air emissions occur as a result of the combustion of fuels such as coal and diesel. There is broad consensus that air pollution affects millions of people around the world. It leads to early deaths and productivity loss due to lung and heart diseases.

Although developed countries have seen improvements, many developing countries with rapidly growing economies are experiencing worse air quality. The World Bank estimates that more than half of the burden falls on China, India and other economies in Asia.

Air pollution in Asia

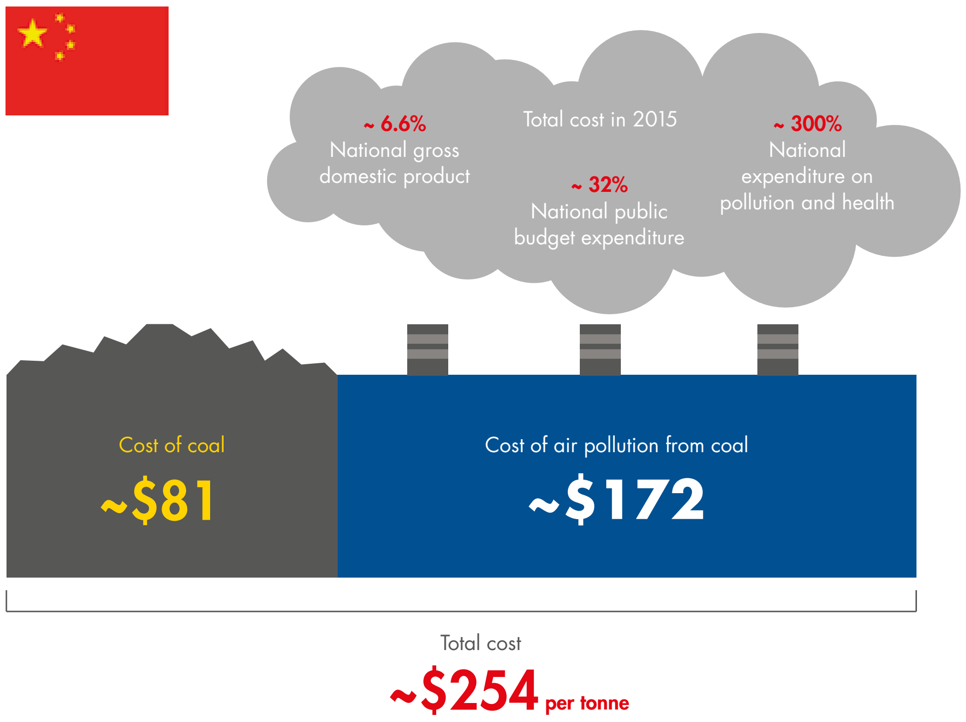


Source: World Health Organization

In China, air pollution associated with burning coal results in costs estimated at around $73 billion, or about 6.6% of gross domestic product, according to a study by the consultancy PwC Strategy&, which specialises in tax, audits and assurance. It represents one-third of China's annual public spending and 300% of public spending on pollution and health.

This study shows that, in line with the government's target, increasing the share of natural gas in the energy mix from 6% today to 10% in 2020 could reduce costs related to air pollution by around $12.5 billion – $3 billion for every additional percentage increase in gas' share.

The cost of air pollution from coal in China



Source: IMF "Getting energy price right", "Externalities of coal 2012" State Statistics Bureau, PWC Strategy & analysis.

The Cost of Coal in China 2015 (US$ Per Tonne).

Data does not include Taiwan

NATURAL GAS | AN ENERGY TRANSITION

Energy transitions

To meet rising global demand for energy while avoiding serious consequences of climate change and air pollution, a transformation of the global energy system is required. This will take place across electricity generation, industry, transport, and the heating and cooling of buildings. These are the four sectors of the economy in which most energy is consumed and greenhouse gas emissions and air pollution are produced.

This transition is already under way. It is proceeding at different paces and producing different outcomes in different countries. The speed of the transition will continue to depend on factors such as the availability of natural resources, national policies to address climate change and local air quality, as well as energy security and affordability. It will also be influenced by the pace of economic growth, technological innovation, and choices made by companies and consumers.

This transformation will span decades and feature an evolution of established energy sources, such as oil, gas and renewables, as well as new and emerging energy technologies. This could require investment of up to $3.5 trillion each year to 2050, to be in line with the objectives of the Paris Agreement, according to the IEA. This is double the current level of investment.

The role of natural gas in the energy transition

Natural gas is a critical component of the energy transition – helping to meet increasing demand while lowering greenhouse gas emissions and improving air quality. It is one of the few energy sources that can be used across all sectors of the global economy. It is used to generate electricity, provide heat for essential industrial processes, heat homes and fuel the transport of people and goods.

Natural gas emits between 45% and 55% lower greenhouse gas emissions than coal when used to generate electricity, according to IEA data. Today, coal-fired power stations produce around 40% of the world's electricity, which represents more than two-thirds of global CO_2 emissions from electricity generation. Using natural gas instead of coal to generate electricity can significantly reduce air pollution. Compared to coal-fired power plants, modern natural gas-fired power plants emit less than one tenth of the pollutants.

Despite the significant role of renewables, they cannot provide all the world's energy needs today. Renewables chiefly power electricity, which only meets around a fifth of global energy demand. For renewables to have a bigger impact, electricity must play a larger part in other key sectors of the economy. As the role of electricity grows, the world will increasingly rely on the electricity supply being reliable and affordable, as well as sustainable. Natural gas supports the integration of variable renewable electricity generation because it can quickly compensate for dips in solar or wind power supply and rapidly respond to sudden increases in demand. Natural gas is a good partner for hydropower, providing a secure electricity supply when there is insufficient rainfall. (See Electricity generation).

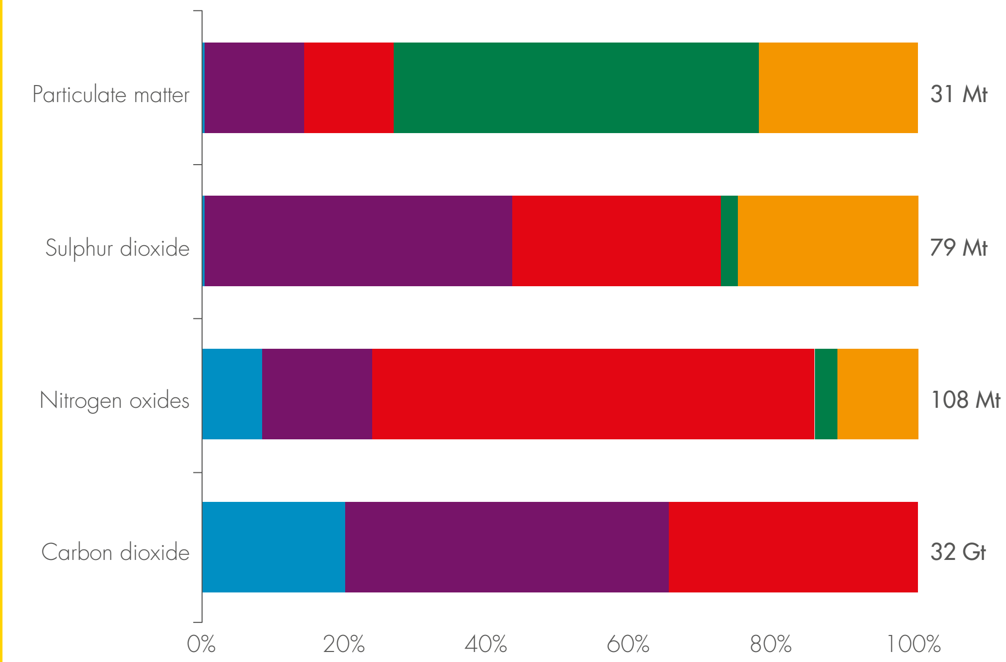
Natural gas will have a central role in the energy transition in the industrial sector. In light industry, such as textiles, switching from coal to gas-boilers can make a significant contribution to cost reductions, lower greenhouse gas emissions and improved air quality. Likewise, in heavy industries such as iron, steel, cement and chemicals, switching from coal to gas to produce the intense heat required in furnaces can significantly reduce emissions. Natural gas will continue to be a central component to produce everyday products such as plastics and fertilisers. (See Industry).

Natural gas is playing a significant part supporting the energy transition in the built environment. In developing economies, it will replace traditional biomass in heating and cooking, helping to reduce the health impacts of localised emissions from other fuels. In developed countries, planning that incorporates infrastructure to accommodate an increasing share of highly efficient, distributed gas-fired combined heat and power (CHP) systems will help to reduce emissions of greenhouse gases and air pollution, particularly where they replace electricity and heat generated from coal or diesel.

The use of natural gas-fired CHPs can also support the integration of low-emissions sources of energy, including geothermal heat and power, solar, wind and batteries. (See The built environment).

Natural gas is playing an important role in the energy transition in the transport sector, as part of a mosaic of fuel and engine solutions. Liquefied natural gas (LNG) is helping diversify the fuel mix and reduce air pollution as a fuel for heavy-duty road transport and shipping. Natural gas is also converted into high-quality cleaner burning gas-to-liquids (GTL) fuels for heavy-duty vehicles, inland and seagoing marine vessels. (See Transport).

Share of natural gas in total energy-related emissions of air pollutants and CO_2 (IEA)



Gas · Coal · Oil · Bioenergy · Non-combustion

Data are for 2015: Mt = million tonnes, Gt = gigatonnes

Source: IEA analysis

These advantages suggest a central role for natural gas in the energy transition. In its New Policies Scenario, the IEA expects that use of natural gas could increase by 45% over the next 25 years. Developing countries are expected to account for more than three-quarters of that growth.

Use of natural gas also has the potential to support economic development in developing countries, for instance through employment during the construction and operation of gas-related infrastructure, or through fiscal revenues from gas trade. Gas provides energy to fuel manufacturing and industrial development. It can also help improve the reliability of electricity supply, supporting productivity in countries where there is limited electricity or outages are frequent.

An abundant, secure and flexible energy source

Natural gas is an abundant, secure and flexible source of energy and the high levels of anticipated demand can easily be met by known levels of recoverable natural gas resources. As technology advances, so does our ability to unlock the world's natural gas resources.

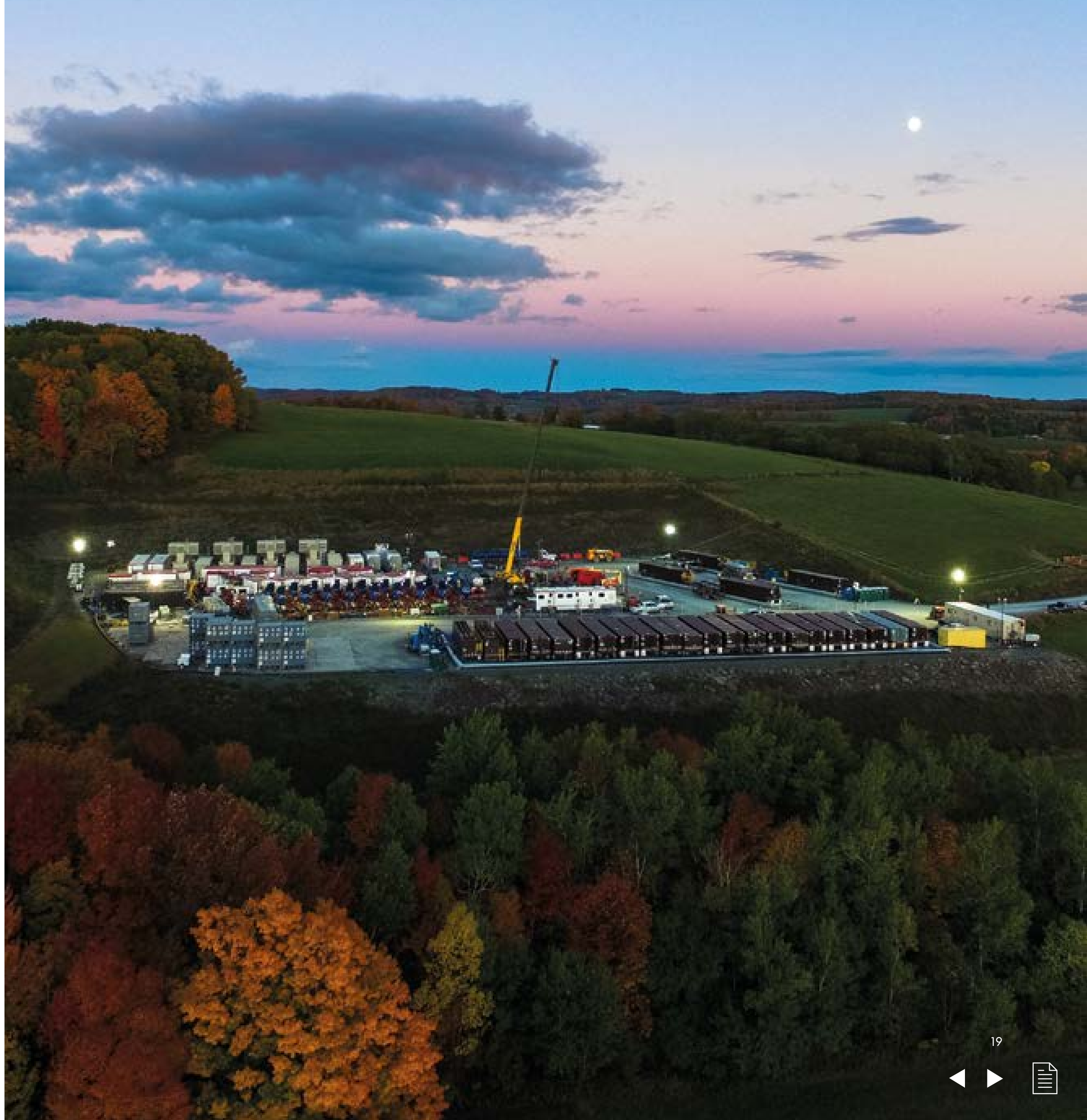
Today, global proven gas resources stand at 769 trillion cubic metres, enough to supply global gas demand for 219 years at current levels of demand, according to the IEA. Conventional gas currently accounts for more than three-quarters of the world's gas supply. Hydraulic fracturing has the potential to unlock large additional volumes of unconventional gas. For countries with large domestic natural gas resources, the impact of developing substantial additional volumes of natural gas can transform economies.

What is unconventional gas?

Until recently, most natural gas has come from rock formations that, once drilled, allow the gas to flow freely. Unconventional gas resources lie trapped in dense rock, inside pores up to 20,000 times narrower than a human hair. A technique known as hydraulic fracturing is used to break open rock and release natural gas. This involves pumping fluids into the well bore at high pressure. The fluids comprise around 99% sand and water, with 1% chemicals added to help the gas flow more freely. Hydraulic fracturing typically takes place a kilometre or more (thousands of feet) below drinking water supplies. Concrete and steel barriers are inserted into the wells as standard practice to prevent any drilling or fracturing fluids from entering local water supplies.

It is important that the industry continues to focus on safety, environmental safeguards, and engagement with local communities to address concerns and help develop local economies. This means considering each project – from the geology to the surrounding environment and communities – and designing activities using technology and approaches suited to local conditions.

IT IS IMPORTANT THAT THE INDUSTRY CONTINUES TO FOCUS ON SAFETY, ENVIRONMENTAL SAFEGUARDS, AND ENGAGEMENT WITH LOCAL COMMUNITIES TO ADDRESS CONCERNS AND HELP DEVELOP ECONOMIES



Natural gas can be transported by pipeline or ship to where it is needed, whether for electricity generation, powering industry, heating buildings or transport.

Pumped through pipelines, gas can be cost-effectively transported over long distances and as part of an integrated gas transport network. The total length of the world's natural gas pipelines would stretch to the Moon and back eight times.

When pipelines cannot cost-effectively reach consumers, natural gas can be cooled to make a liquid, shrinking its volume for shipping to where it is needed or to the start of a pipeline. New and existing pipelines and the rapid growth of LNG, in combination with new sources of natural gas from both conventional and unconventional sources, are increasing energy supply, security, diversity and flexibility.

There has been rapid growth in the number of countries supplying LNG, almost doubling between the start of the century and 2017. This has significantly increased the flexibility and security of gas supply options for importing countries. For example, in 2017 China imported natural gas from more than 20 countries, via a combination of both pipelines and as LNG.

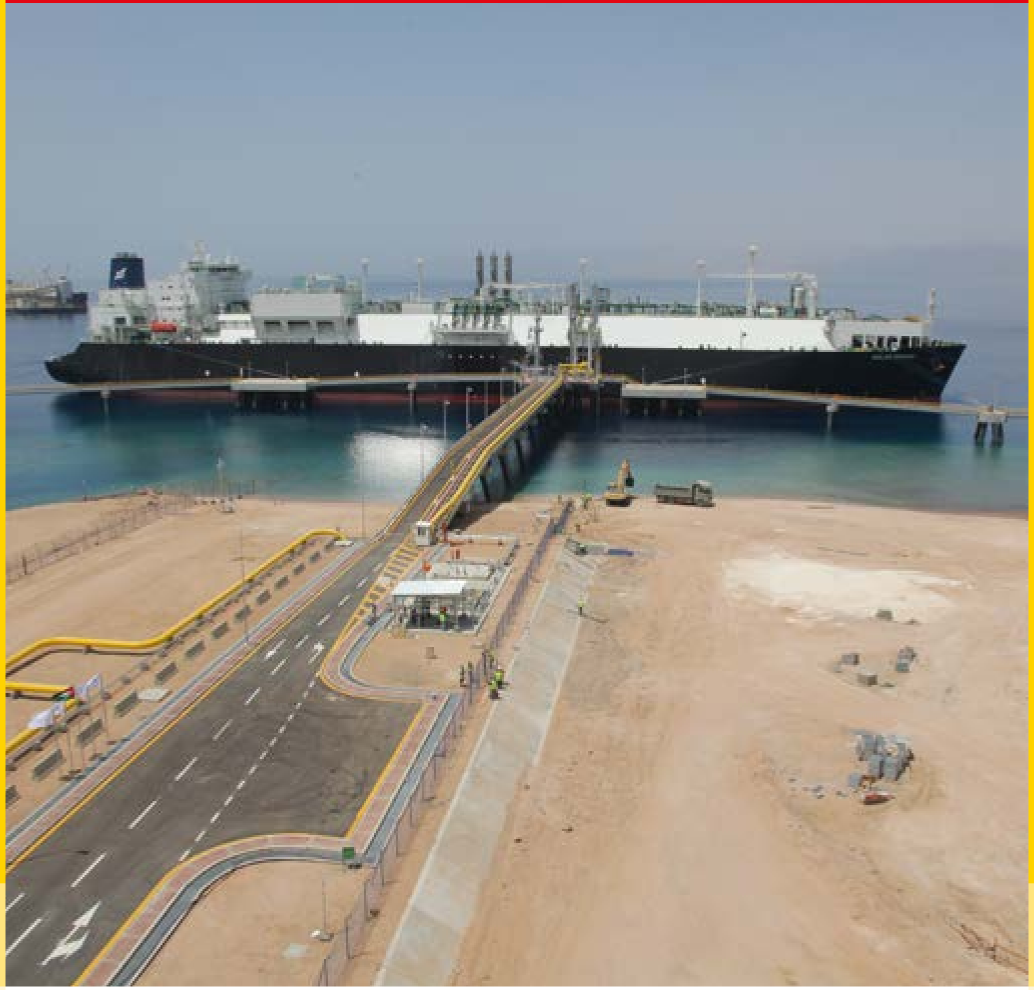
The number of countries importing LNG has quadrupled, with LNG trade increasing from 100 million tonnes in 2000 to 300 million tonnes in 2017, according to IHS Markit. Floating storage and regasification units (FSRUs) present a fast, flexible and economically competitive option for countries looking to import LNG. These vessels can be docked in a port to regasify LNG and feed gas into a transmission or distribution network.

FSRUs are scalable, quick to deploy and require less capital than an onshore terminal or pipeline project. This makes them particularly attractive to developing countries seeking gas supply for an identified source of demand, such as a power plant or industrial area, and as the starting point for a wider expansion of gas infrastructure. They can also help reduce risk for investors and lower the hurdles for access to finance.

FSRUs also offer benefits to countries looking to replace or complement existing gas supplies, or to balance seasonal variations in hydropower. Currently, there are over 20 FSRU terminals in operation worldwide and many more under construction, according to the International Gas Union.

BETWEEN 2000 AND 2016, THE NUMBER OF COUNTRIES IMPORTING LNG HAS INCREASED FROM 10 TO 40

CASE STUDY: AQABA FLOATING STORAGE AND REGASIFICATION UNIT, JORDAN



IN 2015, A GOLAR FSRU WAS MOORED OFF THE RED SEA PORT OF AQABA IN JORDAN. IT PROVIDED RELIEF TO JORDAN'S POWER PRODUCERS, WHICH HAD EXPERIENCED MAJOR CROSS-BORDER GAS PIPELINE SUPPLY DISRUPTIONS.

Prior to the disruptions, 92% of thermal electricity generation had been from natural gas. This was reduced to as little as 8% in 2014, but recovered to 90% once the FSRU was running at full capacity.

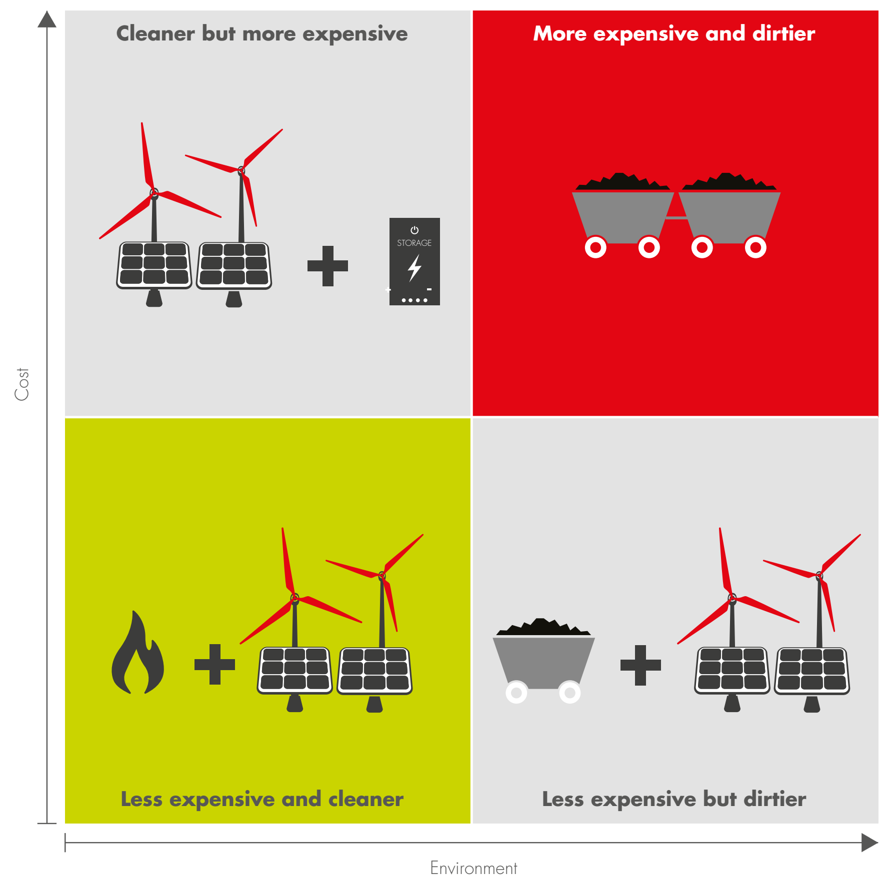
Fulfilling the potential of natural gas

A combination of natural gas and renewables offers countries a predictable, reliable, flexible and cost-effective pathway to a lower emissions energy system.

Fulfilling the potential of natural gas in the global energy supply system depends largely on economics, policy and the environmental benefits of natural gas.

Gas becomes increasingly competitive with other fossil fuels when all costs are considered. These include the costs associated with purchasing and using the fuel, as well as the anticipated costs associated with the resulting greenhouse gas emissions and negative impacts of air pollution on the environment and human health.

Cleaner and more affordable energy



In the USA and UK, a combination of economics, technical developments and policy has increased demand for natural gas in the electricity sector. In the USA, the shale gas revolution saw the share of gas-fired electricity generation increase from 18% to 32% between 2002 and 2016, corresponding with a decline in the share of coal-fired electricity generation from 49% to 29%, according to the US Energy Information Administration (EIA). Over the same period, the share of renewable electricity increased from 9% to 14%, driven mainly by state-level renewable portfolio standards. Meanwhile, CO_2 emissions from the electricity sector decreased by 20%.

What is carbon pricing?

Governments acting to put a price on carbon emissions (often referred to as "carbon pricing") can help reduce emissions and encourage greater investment in energy sources that produce little or no carbon.

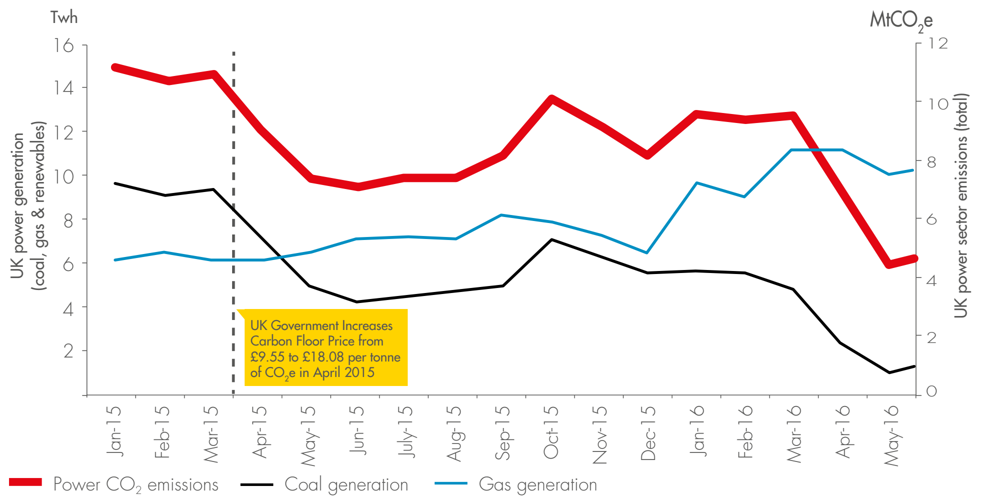
The World Bank has described how a "price on carbon helps shift the burden for the damage back to those who are responsible for it, and who can reduce it. Instead of dictating who should reduce emissions where and how, a carbon price gives an economic signal and polluters decide for themselves whether to discontinue their polluting activity, reduce emissions, or continue polluting and pay for it. In this way, the overall environmental goal is achieved in the most flexible and least-cost way to society. The carbon price also stimulates clean technology and market innovation, fuelling new, low carbon drivers of economic growth."

One option is for governments to tax emissions, which directly establishes a cost for emitting CO_2. An alternative is to cap emissions and allow a price to develop through the trading of emissions allowances.

In the UK, a government-led "carbon price" floor of £18 per tonne introduced in April 2015, contributed to a 56% increase in demand for natural gas in the power sector and a 73% decrease in demand for coal-fired electricity generation in the first half of 2016, according to Aurora Energy Research. As a result, CO_2 emissions from the UK power sector decreased by 24%. In April 2017, the UK went a day without using any coal to generate electricity for the first time since 1882.

United Kingdom power sector carbon price floor

UK power generation from gas and coal & power sector CO_2e emissions



Source: Aurora Energy Research

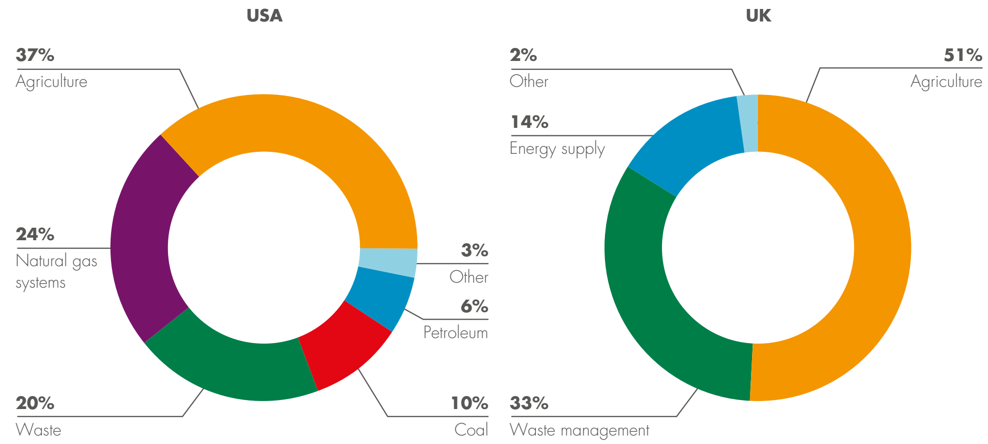
In addition to carbon pricing, government policymakers have applied regulatory approaches including performance standards and emissions limits to accelerate reductions across the power sector, industry, modes of transport and the built environment. In China, the government has introduced policies to support a shift from coal to gas. This is part of a comprehensive plan to reduce carbon intensity by 18% from 2016 to 2020, and tackle higher levels of air pollution. This could see gas demand increase by 90% by 2025, according to the IEA's New Policies Scenario. Demand could increase by 8.7% each year to 2022.

Regulatory, economic or technical barriers can also impact gas demand, sometimes to the advantage of more carbon intensive options, including coal. Here, coal-to-gas switching can be supported by changes to policy frameworks that support, for example, a government-led change in tariff structure, the re-allocation of electricity generation slots, or alternative dispatch schedules.

Financing gas and electricity transmission infrastructure can also present challenges, particularly in developing countries. In these countries, loans, guarantees and other forms of financial risk mitigation are often important in initiating development of the necessary infrastructure. Given the relative complexity of gas markets, training and capacity building are often also important to ensure that countries realise the full benefit of natural gas resources.

The case for natural gas on environmental grounds requires high standards throughout the gas supply chain. Realising the full potential of natural gas in the energy system will also require the gas industry to demonstrate progress in further improving its environmental footprint. This includes reducing emissions of methane from the natural gas supply chain, which can diminish the relative CO_2 emissions benefits of natural gas.

Managing methane emissions from the natural gas value chain



Note: Categories for measurement of emission sources are not directly comparable.

Methane is a potent greenhouse gas. When it is released into the atmosphere it has a much higher global warming impact than CO_2.

Around 60% of the world's total methane emissions occur naturally – including from wetlands, oceans and vegetation decay. The remaining 40% of methane emissions are the result of human activities, such as livestock farming and energy production.

About 13% of total global methane emissions come from oil and gas related activities. The IEA estimates that there were 76 million tonnes of methane emissions from oil and gas operations in 2015, split roughly equally between the two.

Natural gas consists mainly of methane. Efforts to address climate change therefore require the industry to reduce both deliberate and unintended methane emissions from the gas value chain, from production to the final consumer. These emissions usually occur in three ways: emissions of unburnt methane from fuel combustion; venting, for example, from equipment for safety reasons; and unintended emissions, such as small leaks.

It is important that the gas industry continues to monitor and reduce methane emissions. This includes wider implementation of methane leak detection and repair programmes. It also includes deployment of advanced technologies, such as optical imaging and pro-active maintenance and modernisation of pipeline systems.

High levels of methane emissions reduce the greenhouse gas benefits of gas compared to other fuels. However, the lifecycle emissions of gas remain significantly lower than those of coal in both electricity generation and industry.

Source: US EPA 2017, UK BEIS 2017

CHAPTER 2:
ELECTRICITY GENERATION

2

NATURAL GAS | ELECTRICITY GENERATION

The energy transition in electricity generation

A reliable, affordable and sustainable supply of electricity is vital for social and economic development. It is used to light rooms, refrigerate food and medicine, power computers, and charge mobile phones. Apart from during the global economic crisis in 2008-2009, electricity generation has increased every year since 1971, reaching 23,816 terawatt hours (TWh) in 2014. Yet, even today, 1.1 billion people – one in every six people on the planet – continue to live without access to electricity, according to the IEA. A further billion people only have access to unreliable or unsafe electricity supplies.

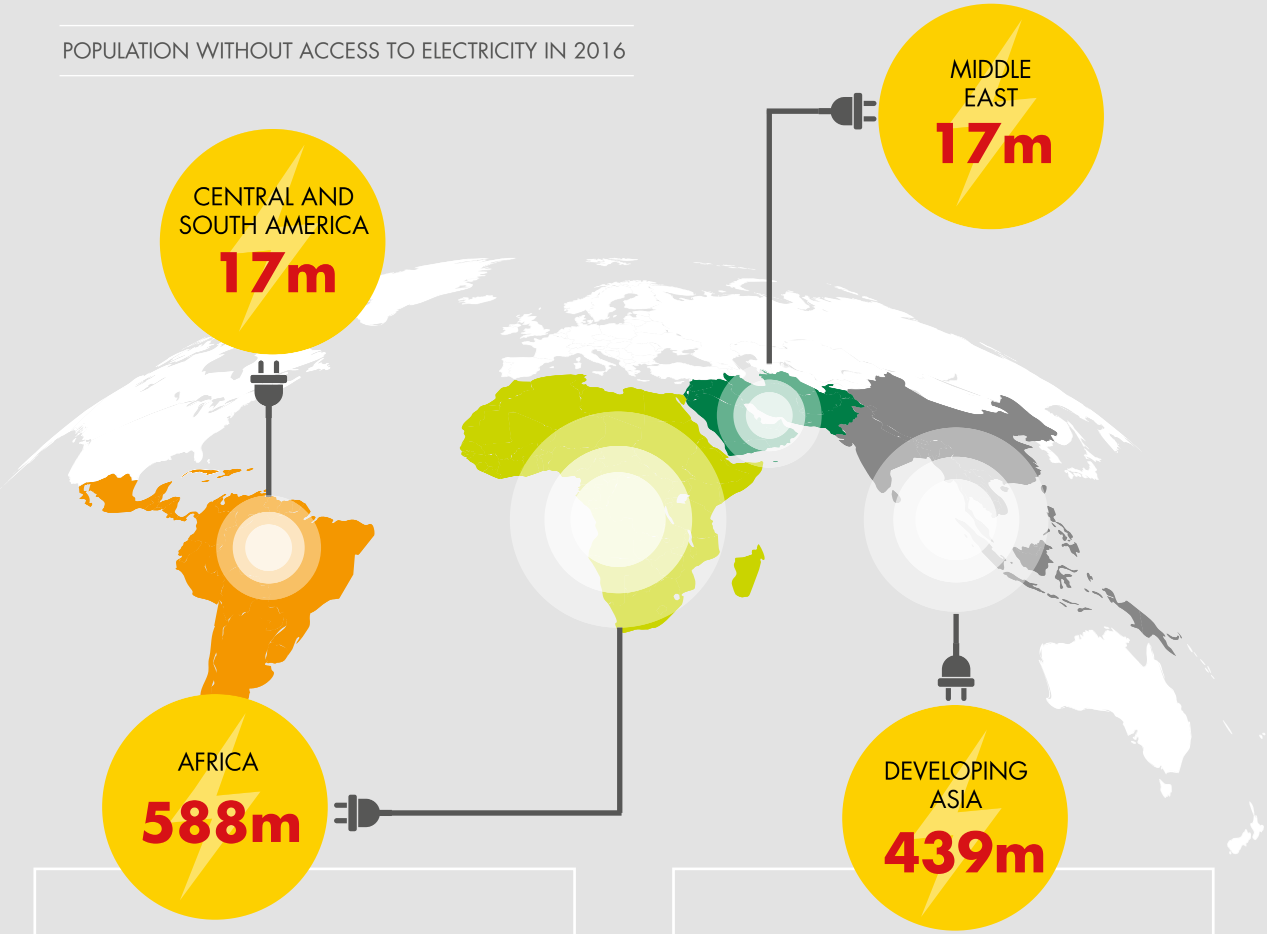
Electricity generation differs from other energy sectors by being 'intermediate'. This means it converts primary energy into electricity for use in other sectors. Electricity does not create emissions at the point of use. However, the source of the electricity has a significant impact on lifecycle emissions. When electricity is generated from cleaner energy sources it can play a key role in reducing greenhouse gas emissions and air pollution in transport, the built environment and industry.

Today, electricity provides around a fifth of final energy consumed globally and is responsible for 40% of energy-related greenhouse gas emissions, according to the IEA. When generated from lower carbon energy sources, increased use of electricity will support emissions reductions in the power sector, as well as across end-use sectors in industry, transport and the built environment. By mid-century, electricity could account for as much as 50% of energy use and up to 40% by 2040. Much of this demand growth will come from developing countries, particularly Sub-Saharan Africa and South Asia, where 95% of those with no electricity live.

> TODAY, ELECTRICITY PROVIDES AROUND A FIFTH OF FINAL ENERGY CONSUMED GLOBALLY AND IS RESPONSIBLE FOR 40% OF ENERGY-RELATED GREENHOUSE GAS EMISSIONS

1.1 billion people still do not have access to electricity

POPULATION WITHOUT ACCESS TO ELECTRICITY IN 2016



CENTRAL AFRICA	172m
EAST AFRICA	98m
WEST AFRICA	175m
SOUTH AFRICA	8m
OTHER SOUTHERN AFRICA	135m

INDIA	239m
INDONESIA	23m
OTHER SOUTH EAST ASIA	42m
OTHER DEVELOPING ASIA	135m

Source IEA World Energy Outlook 2017

The role of natural gas in electricity generation

Natural gas-fired electricity generation has an important role to play in the energy transition. It can help to reduce greenhouse gas emissions and air pollution by displacing coal and oil-fired generation and supporting the integration of variable renewables into the energy mix. Natural gas also has the potential to significantly contribute to economic development in developing countries. Secure supplies of natural gas can help improve the reliability of power supply, supporting productivity where there is limited existing electricity supply or power outages are commonplace.

Historically, the scale-up in the availability of gas has dramatically changed the energy landscape and provided countries with an important opportunity to power growth. According to the IEA's New Policies Scenario, more than 380 gigawatts (GW) of new gas-fired power plants could be needed in developing countries in Asia over the next 25 years to support energy needs and economic development.

Reducing greenhouse gas emissions

Despite the promise of renewable electricity, it cannot provide all the world's energy needs. After a period of rapid growth, renewables account for around one-quarter of global electricity generation, with wind and solar energy sources accounting for around 5% of global electricity generation today. Renewables, such as solar and wind power, are also intermittent, requiring sufficient back-up to ensure reliable electricity supply when there is limited sun or wind. Today, coal accounts for around 40% of global power generation and contributes more than two-thirds of CO_2 emissions from electricity generation. While generation growth has slowed, CO_2 emissions from coal-fired electricity generation would need to decline by an average of 3% each year to 2025 to be on track with the goals of the Paris Agreement, according to the IEA.

Natural Gas emits between 45% and 55% lower greenhouse gas emissions than coal when used to generate electricity, according to IEA data. Switching from coal to gas turbines and combined-cycle plants will be critical to reducing greenhouse gas emissions. In distributed energy systems, gas-fired combined heat and power units also produce significantly fewer greenhouse gas emissions than coal-fired units. (See The built environment).

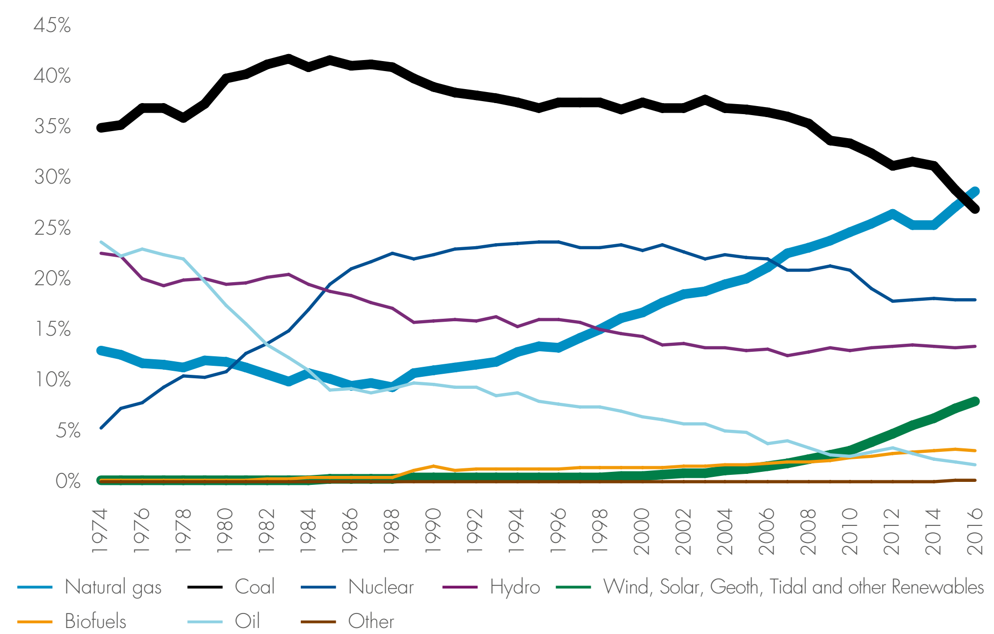
Displacing coal-fired power plants and diesel generators with a combination of gas-fired electricity generation and renewables is a fast and cost-effective way to reduce greenhouse gas emissions from the power sector, while maintaining reliable supplies of electricity.

Coal-fired electricity generation is on a steep downward trajectory in many countries and global coal generation growth has slowed. However, many countries are still increasing their use of coal for electricity generation. In 2015, new coal capacity additions stood at more than 80 GW, representing more than a quarter of new electricity generation capacity globally. Of this, around 30% was from subcritical plants with lower efficiency and higher emissions, according to the IEA. In China alone, 52 GW were added and around 150 GW are under construction. In India, where three-quarters of electricity is generated from coal, generation use of coal rose by 3.3% in 2015.

In countries, such as India, where diesel generators are common, usually due to unreliable power supply, a greater role for gas can bring economic and environmental benefits. For example, if one 100-MW gas turbine replaces 200 diesel generators with a capacity of 500 kW each, around $30 million could be saved in fuel cost each year, while significantly reducing greenhouse gas emissions and air pollution, according to the IEA.

In developing countries, financing the necessary gas and electricity infrastructure can be challenging. Commercial entities, as well as independent financial institutions, such as international development banks, have an important role to play in supporting access to the required loans, guarantees and other forms of financial risk mitigation. Training and capacity building can also help develop the necessary regulatory and market structures.

The Organisation for Economic Co-operation and Development (OECD) countries electricity generation by energy source



In many economies, huge structural shifts are taking place in electricity generation, including switching from coal to gas, a rapid ramp-up of renewables and a decline in nuclear.

Source: OECD

"GAS PLAYED AN IMPORTANT PART IN RECENT POSITIVE CO_2 EMISSIONS TRENDS IN MANY COUNTRIES AND IN THE OVERALL FLATTENING OF GLOBAL ENERGY RELATED EMISSIONS" – IEA 2017

Reducing air pollution

Across the world, the rapid growth of cities is focusing attention on the environment and health impacts associated with air pollution from electricity generation, particularly when power plants are located close to urban centres.

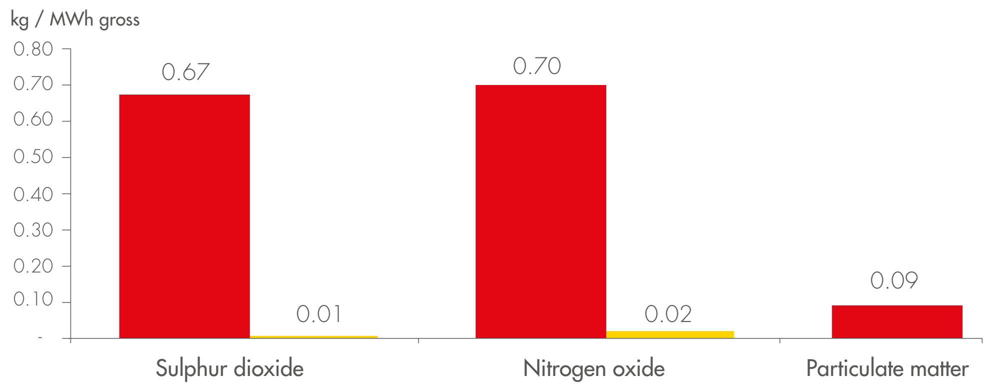
Air pollution is the world's largest environmental health risk. Emissions of pollutants, including particulate matter, sulphur dioxide and nitrogen oxide have major adverse impacts on human health. According to the IEA, coal use is the largest source of global emissions of sulphur dioxide. This is a cause of respiratory illness and a precursor of acid rain, which has a major negative impact on forests, lakes and agricultural yields.

The use of natural gas instead of coal in electricity generation significantly reduces pollution. Compared to coal-fired power plants, modern natural gas-fired power plants emit less than one-tenth of the sulphur oxides, nitrogen oxides, particulates and heavy metals.

Fitting coal-fired power plants with technologies that reduce the amount of pollutants emitted can help. However, this does not mean they will always be deployed and their effectiveness depends on regulatory and operator enforcement.

Even if sulphur and nitrous oxides and other pollutants are removed, coal ash still needs to be disposed of and can lead to local water contamination. Coal-fired power plants are also a major source of mercury emissions that can harm the brain, heart, kidneys, lungs and immune system. In the USA, coal plants account for around 40% of all mercury emissions resulting from human activity. Between 2002 and 2011, a switch from coal to other fuels, as well as the installation of control technologies at coal power plants, contributed to a 50% decrease in mercury emissions.

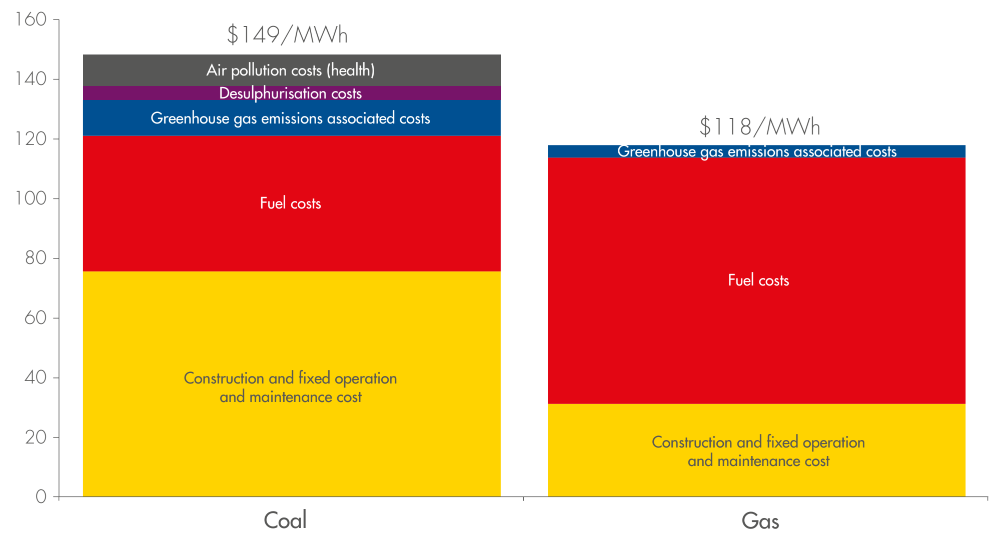
Air pollution from gas-fired power plants compared with coal-fired power plants



■ Coal Emissions, (Supercritical Pulverized Boiler) ■ Natural Gas Emissions (Combined Cycle Turbine)

Source: US Department of Energy National Energy Technology Laboratory 2015

CASE STUDY: THE TOTAL COST OF ELECTRICITY GENERATION FROM COAL AND GAS IN THE PHILIPPINES



Source: Power Generation in the Philippines 2015, IHS Markit (40% capacity)

Reducing use of water

Many parts of the world are experiencing 'water stress', where the supply of water is not meeting demand. Natural gas-fired power plants consume less than 50% of the water needed for coal-fired electricity generation. Coal requires substantial water volumes at every stage – from mining and washing the coal to burning it in power plants and treating the combusted waste. It accounts for around 7% of all water use globally.

The World Health Organization estimates that every person requires between 50 and 100 litres of water each day for the most basic needs. Annually, the world's installed coal-fired power plant units consume enough water to meet the needs of more than 1 billion people, according to a Witteveen+Bos report for Greenpeace International. If the water that the coal industry uses to mine hard coal and lignite is included, it equates to 1.2 billion people. Water saved by switching from coal to natural gas can be used in households, industry and agriculture.

Today, around 40% of coal-fired power plants are in areas with high levels of water stress. Building more coal-fired power plants in these regions threatens to intensify competition with other water users. Even plants that use sea water or dry-cooling technologies require significant amounts of fresh water for scrubbing air pollutants.

NATURAL GAS-FIRED POWER PLANTS CONSUME LESS THAN 50% OF THE WATER NEEDED FOR COAL-FIRED ELECTRICITY GENERATION

CASE STUDY: THE USE OF WATER IN ENERGY AND AGRICULTURE IN INDIA

BY 2050, INDIA MAY BE THE MOST POPULOUS COUNTRY WITH 17% OF THE GLOBAL POPULATION, WHILE ONLY HAVING 4% OF THE WORLD'S FRESH WATER RESOURCES.

This is already having an impact on farmers in Maharashtra state, where there is tension between the use of water for agriculture and energy. Several coal-fired power plants have reduced operations, sometimes for months, because of a lack of water.

Natural gas supports the integration of renewables

Renewable electricity generation, such as wind and solar, will be critical to meeting growing global energy demand while reducing emissions and improving air quality. Electricity generation from renewables expanded by more than 30% between 2010 and 2015 and could reach 40% of total global electricity generation by 2040, according to the IEA.

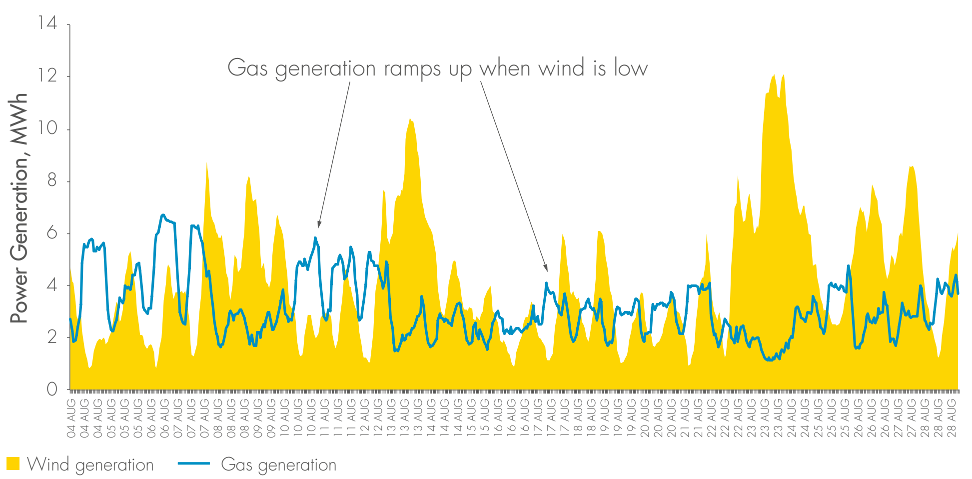
Demand is being driven by cost reductions and policies aimed at enhancing energy security and sustainability as well as reducing CO_2 emissions and improving air quality. Today, renewables represent around a quarter of electricity generation.

Despite rapid growth, renewables such as wind and solar are variable energy sources, which means they only produce electricity when there is sufficient sun or wind. Natural gas-fired power plants provide a competitive and flexible back-up to variable renewables today. They can reach full output in minutes, providing electricity almost instantaneously and rapidly responding to lulls in solar or wind power supply and to surges in demand. By contrast, in addition to producing higher levels of CO_2 and air emissions, coal-fired power stations often require long and costly start-up periods to pre-heat their boiler and steam systems before they can start supplying power to the grid.

Gas-fired power plants can often also be built closer to where electricity is needed, such as towns and cities, because they require less land, produce much lower localised air pollution than coal, and have a different risk profile to nuclear power plants. This helps to increase the speed and efficiency at which electricity can be delivered.

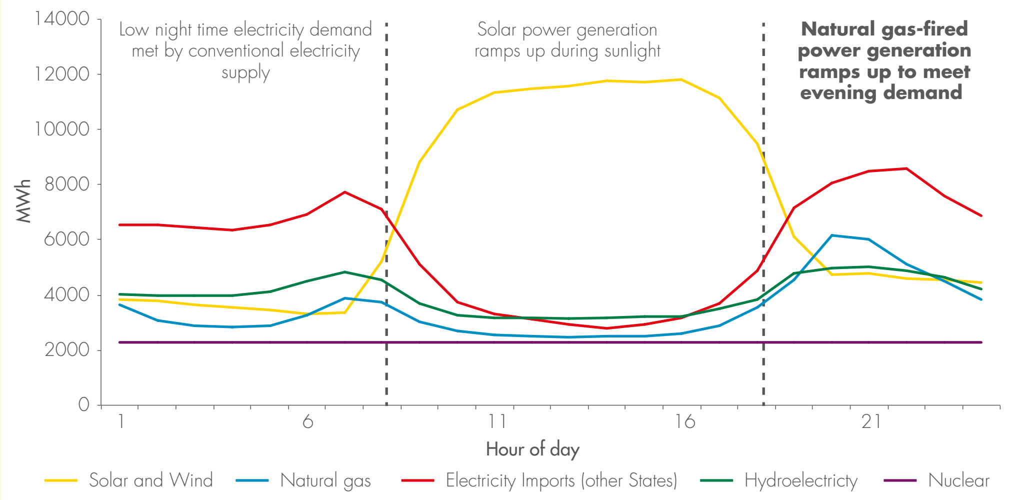
Gas-fired power plants ramp up to provide flexible backup to variable renewables

Spain 2015



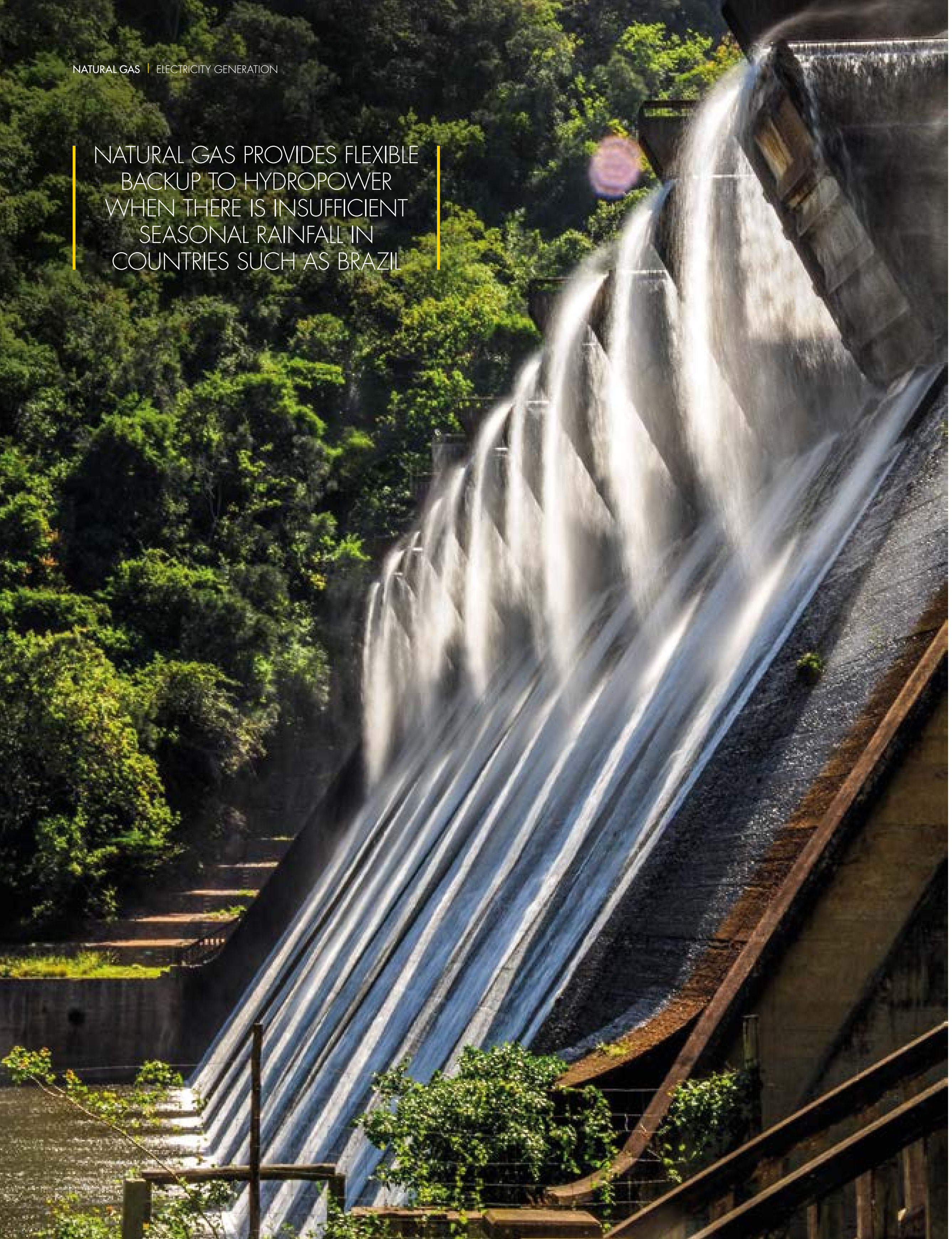
Source: Red Electrica de Espana 2015

CASE STUDY: FLEXIBLE GAS GENERATION INCREASES TO SUPPORT VARIABLE SOLAR GENERATION IN CALIFORNIA



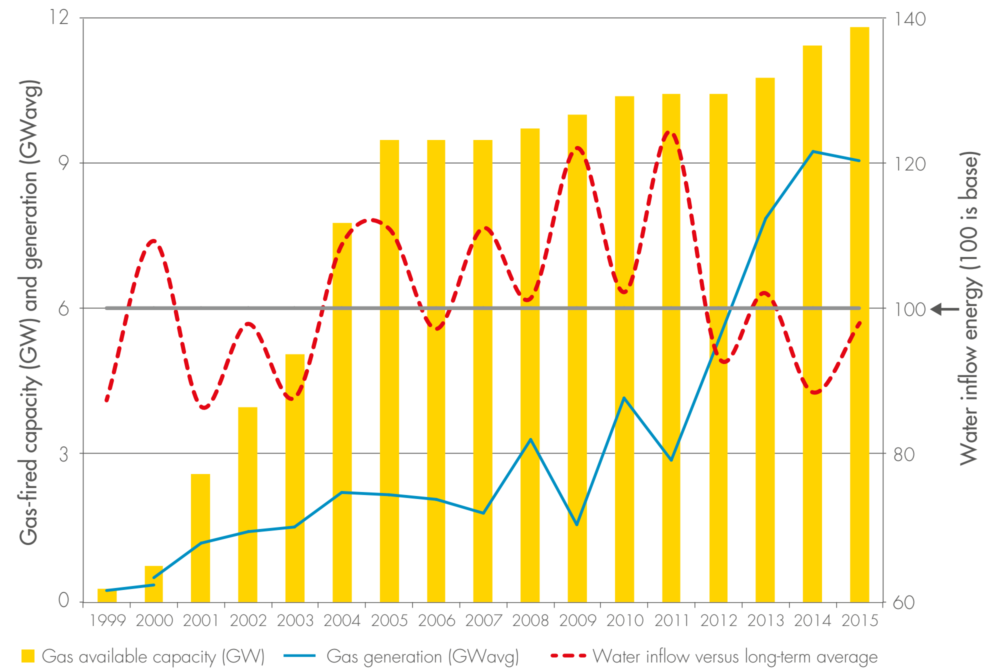
Source: California Independent System Operator, 2016

NATURAL GAS PROVIDES FLEXIBLE BACKUP TO HYDROPOWER WHEN THERE IS INSUFFICIENT SEASONAL RAINFALL IN COUNTRIES SUCH AS BRAZIL



NATURAL GAS | ELECTRICITY GENERATION

Natural gas supports variable hydropower in Brazil



AN INCREASING SHARE OF ELECTRICITY SUPPLIED BY VARIABLE RENEWABLE ENERGY SOURCES IS MAKING IT INCREASINGLY CHALLENGING FOR GOVERNMENTS AND UTILITIES TO DEVELOP ELECTRICITY SYSTEMS THAT MATCH SUPPLY AND DEMAND EFFICIENTLY.

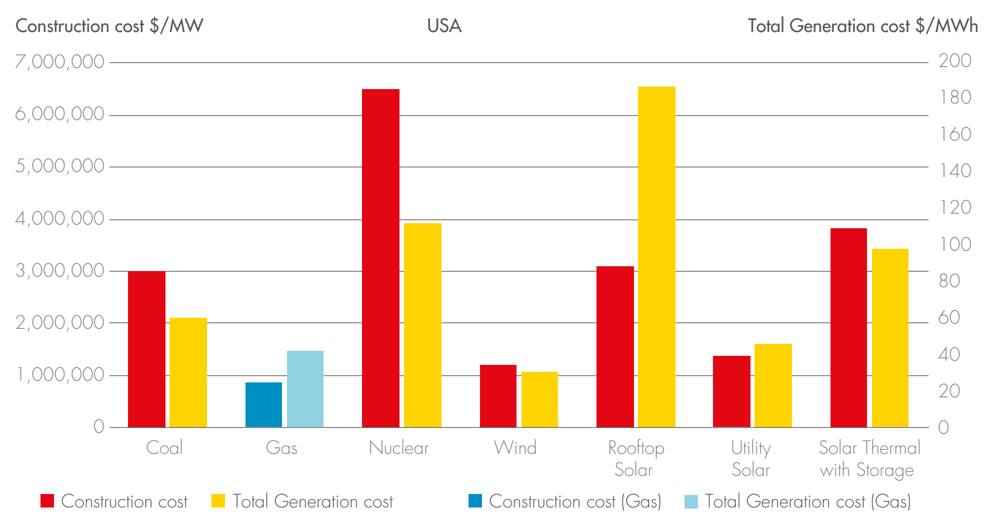
In Brazil, hydropower provides around 90% of electricity when there is sufficient rainfall. In years when there is not enough rain, gas-fired power plants make up the shortfall. Many of the gas-fired power plants in Brazil today were built in response to severe water shortages in 2001 and 2002. In 2015, a severe drought saw hydropower's share of electricity supply drop to around 70%.

Source: IHS Markit, Aneel

Energy storage technologies, including batteries, will increase the flexibility of the grid and facilitate integration of renewable electricity sources. In addition to batteries, other energy storage systems include pumped hydropower or conversion of surplus electricity into storable thermal energy or hydrogen. These options are maturing rapidly. Technological innovations have lowered costs, however cost-competitive large-scale battery storage and delivery of electricity, equivalent to that provided by an average power station, is not expected for at least a decade, according to a study by IHS Markit. While batteries can store energy for the short term, technologies are also needed to match seasonal variations in demand for heat or cooling in many parts of the world.

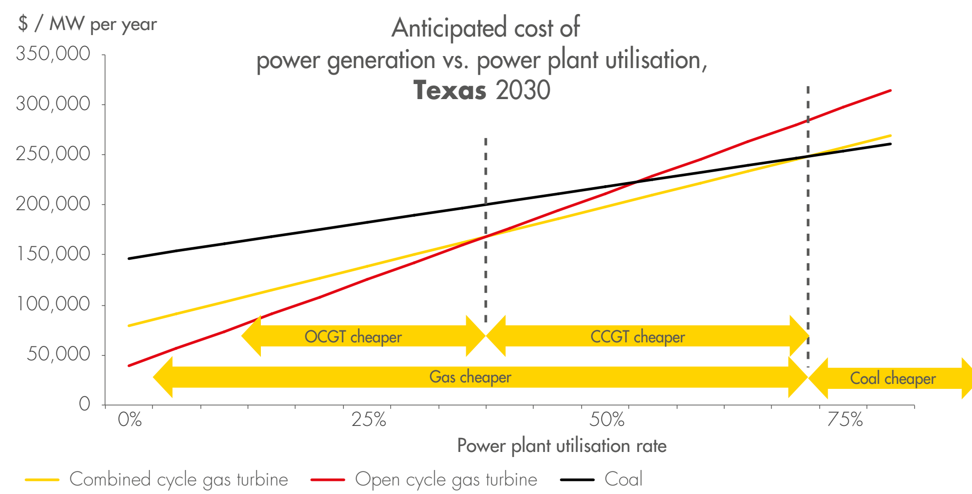
The ability to build and operate gas-fired power plants quickly, at lower cost and in a range of sizes, offers important benefits. As the share of renewable electricity generation increases, the requirement for electricity generated from traditional coal, gas and nuclear power plants is anticipated to decline, often with utilisation rates of less than 60% of their full capacity. As this occurs, the economic advantage of gas-fired power plants increases, relative to coal and nuclear plants. This is because, on average, gas-fired power plants can be built twice as fast as coal and nuclear plants, cost less to build and are cheaper to maintain. They are therefore able to recover their investment costs and operate at a profit sooner than coal and nuclear plants. Nuclear plants often also have technical constraints to operating at lower utilisation rates. In addition, the shorter construction and development time of gas-fired power plants reduces the time between initial investment and generation of electricity and can help reduce investment uncertainty.

Comparative construction and operating costs of power generation technologies



Source: Levelised cost of energy 2017 Lazards

New gas-fired power plants become increasingly competitive with new coal-fired power plants as utilisation levels decrease



Source: IHS Markit

Carbon capture, utilisation and storage in electricity generation

Longer term, natural gas-fired power plants could use carbon capture, utilisation and storage (CCUS) to capture up to 90% of their CO_2 emissions.

The Intergovernmental Panel on Climate Change (IPCC) suggests that CCUS will be required on a major scale, across both electricity generation and industry, to meet long-term climate change ambitions. According to the IEA, CCUS will need to account for 14% of CO_2 reduction by 2060 to be on track with the goals of the Paris Agreement. To do so, CCUS would need to remove around 1 billion tonnes of CO_2 a year by 2030 and almost 7 billion tonnes by 2060.

The Energy Transition Commission states that more than 100 new CCUS plants need to be built each year from 2020 to 2040 to meet the Paris goals. Reducing emissions will be more difficult, disruptive and expensive unless the use of CCUS becomes widespread. (See CCUS in Industry).

What is carbon capture utilisation and storage?

Carbon capture and storage (CCS) is the name given to a set of technologies that capture and store CO_2 deep underground, preventing its release into the atmosphere. The three core elements of capture, transport and storage have been demonstrated for many years in the oil and gas industry.

It can be used to reduce CO_2 emissions from both the power and industrial sectors. There are 21 large-scale CCS projects in operation or under construction globally, with a combined capacity to capture around 40 million tonnes of CO_2 each year. That is equivalent to taking 10 million cars off the road.

Carbon capture, utilisation and storage (CCUS) includes the use of CO_2 for enhanced oil recovery, agriculture and the production of building materials.

How CCS works

1 Capture
CO_2 capture separates CO_2 from gas, before it is emitted, using a chemical solvent. The captured CO_2 is separated from the solvent and compressed into a liquid form for transport.

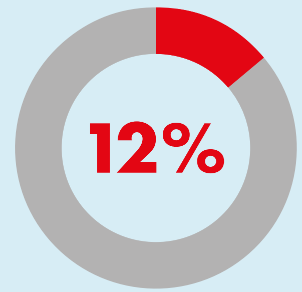
2 Transport
CO_2 is generally pumped through a pipeline, taking the CO_2 from the industrial site where it has been produced, to its storage site which may be onshore or offshore.

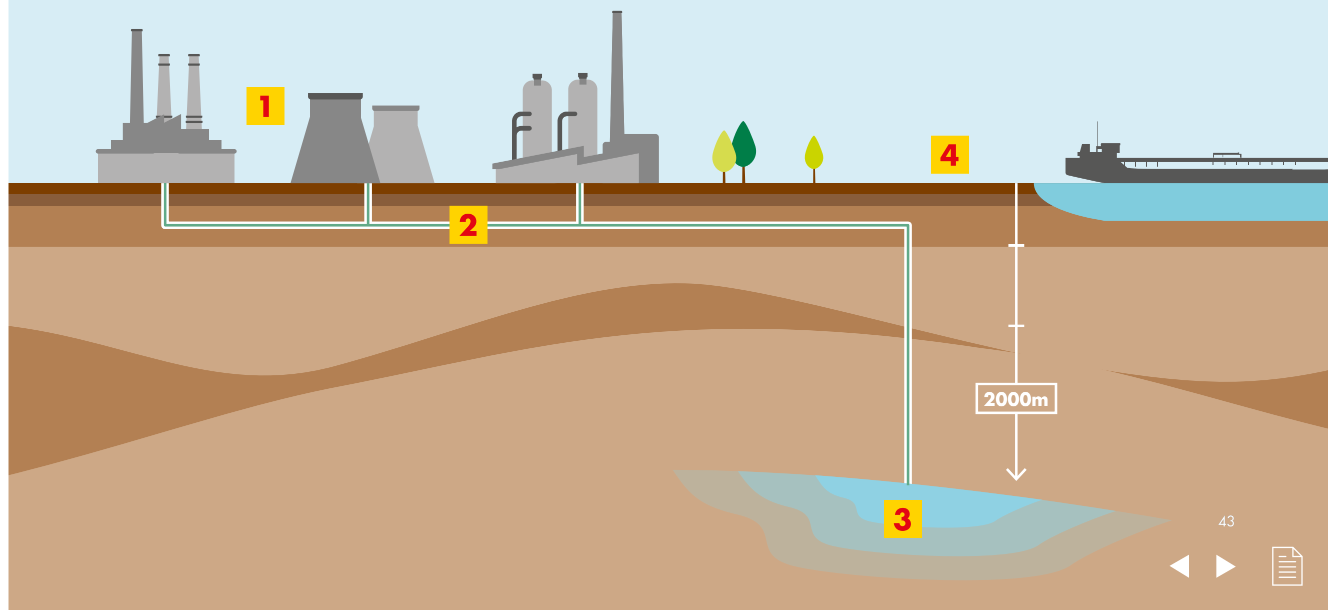
3 Storage
CO_2 is injected deep underground into the microscopic spaces in porous rocks. A layer of impermeable rock, called a cap rock, lies directly above the porous rocks ensuring that the CO_2 remains there permanently.

4 Measuring, monitoring and verification
Monitoring of storage sites takes place within the storage reservoir, as well as at the injection well, where sensors can detect small changes in pressure or CO_2 levels. In addition, a number of monitoring technologies can be incorporated within the geosphere, biosphere and atmosphere surrounding the storage site to make sure the CO_2 is stored permanently.

CCS Contribution

THE IEA CONSIDERS THAT CCS, AS PART OF A PORTFOLIO OF ACTIONS, COULD ACCOUNT FOR **12% OF TOTAL ENERGY-RELATED CO_2 REDUCTIONS NEEDED BY 2050**.





CHAPTER 3: **INDUSTRY**

3

The energy transition in industry

The industrial sector is made up of a variety of sub-sectors that produce the building blocks of modern economies, including iron, steel, cement and the chemicals used to support longer, healthier lives and produce many everyday products.

Even assuming significant improvements in the efficiency with which economies produce, consume and recycle, demand for these and other materials will increase significantly to meet the needs of a growing global population and economy. In 2015, industry accounted for 38% of global energy use and 24% of all global CO_2 emissions, according to the IEA. Reducing energy demand and emissions from the industrial sector over the long term, without compromising economic and social development goals will require effective implementation of energy efficiency strategies, switching to lower-carbon fuels and raw materials, and the best available technologies such as carbon capture, utilisation and storage.

Increasing use of cleaner-burning natural gas in industry, where it displaces coal and oil, offers the potential to significantly reduce greenhouse gas emissions and air pollution today. These benefits are being recognised by policymakers, particularly in rapidly growing economies such as China. In Northeast China, industrial coal to gas switching is estimated to have added around 17 billion cubic metres to overall gas consumption in 2017, driven largely by policies to reduce air emissions. That is enough gas to supply Belgium for a year. According to the consultancy Wood Mackenzie, global industrial gas demand is likely to increase by 45.5% between 2015 and 2035, with growth of 107% in China and 108% in India. Demand is expected to rise significantly in the chemicals sector, with growth in the need for everything from food packaging to car parts.

Light industry

In light industries, such as textiles, the use of small boilers heated by coal are a major cause of local air pollution. Diesel-fuelled backup generators, often necessary for businesses to protect themselves from power outages, are costly and a source of local air pollution. Here, displacing coal and diesel with gas boilers can make a significant contribution to lower greenhouse gas emissions, improved air quality and cost reductions. A PwC Strategy& study shows that displacing a single coal boiler with a gas boiler at a leading textile supplier in China's Guangdong Province resulted in a reduction in particulate matter, sulphur dioxide and nitrogen oxide emissions of 70%, 93% and 65% respectively.

Coal-to-gas switching in Lanzhou, China

Lanzhou is the capital of Gansu, a province in Northwest China. Until 2013, Lanzhou was one of the country's most polluted cities, largely because of emissions from industry. Residents referred to it as a 'city which could not be seen on a satellite'.

Following a three-year programme to reduce air pollution, focused on switching from coal to natural gas, emissions were significantly reduced. This resulted in a 40% decrease in hospital admissions related to respiratory conditions, a 68% decrease in associated medical costs and an 18% increase in GDP. Visitor numbers have also increased and, in 2015, Lanzhou won the 'Today's Revolution and Advancement Award' at the UN Paris Climate Conference in recognition of this achievement.

The use of natural gas in industry has other significant benefits. Gas almost completely combusts, while coal produces large volumes of ash and slag, which require expensive handling and disposal. Gas boilers supplied by pipelines do not require on-site fuel storage, loading, or waste disposal. This saves valuable space and associated costs. The study shows that by converting from coal to natural gas, a textile company in Jiangsu on China's east coast has saved more than 100 square metres of space.

In some industries, the reliable and steady temperatures provided by gas boilers can improve product yield and quality. These benefits are accruing to businesses across the paper, textile, food, chemical and pharmaceutical industries in China. For example, in China's Xinjiang Province, a chemical company has increased product revenue by 33% by switching from a coal boiler to a gas boiler. In industries such as ceramic and glass production cleaner fuel combustion in furnaces can also result in higher quality products.

CASE STUDY: CR SNOWFLAKE BEER SICHUAN COMPANY BREWERY, CHINA

CR SNOWFLAKE BEER SICHUAN COMPANY BREWERY IS THE LARGEST MODERN BREWERY IN SOUTHWEST CHINA. TO LOWER COSTS, IMPROVE EFFICIENCY AND REDUCE EMISSIONS, THE COMPANY HAS DEVELOPED A DISTRIBUTED ENERGY SYSTEM BASED ON GAS-FIRED COMBINED HEAT, COOLING AND POWER GENERATION.

Compared to the equivalent coal system, it is expected to improve efficiency by 22%, reduce CO_2 emissions by 43% and reduce sulphur oxide and nitrogen oxide emissions by 165 and 48 tonnes a year respectively. Any surplus electricity can also be sold back to the local grid.

Heavy industry

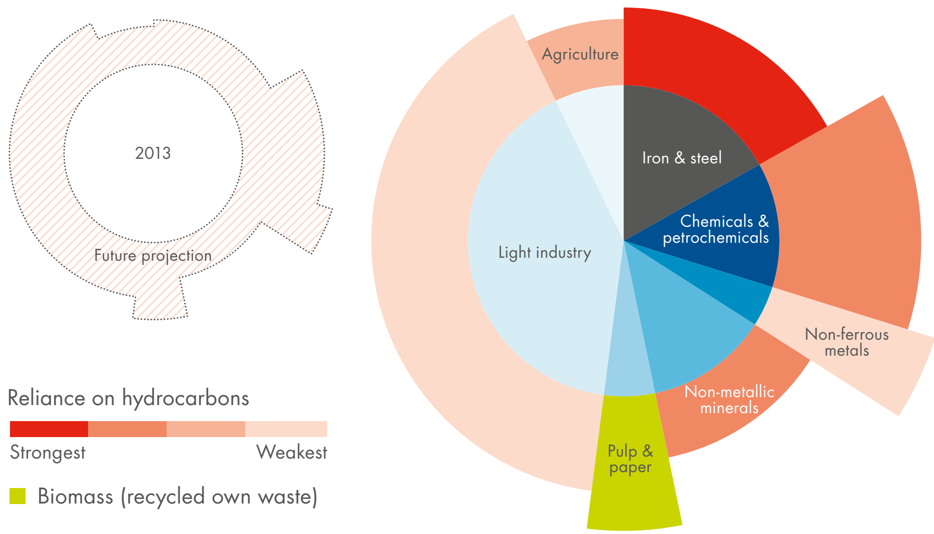
In heavy industry, such as iron, steel, cement, and chemical production, hydrocarbons are required to produce high temperatures or chemical reactions. In these sectors, displacing coal with natural gas can make a significant contribution to lowering greenhouse gas emissions and improving air quality.

Today, half of all iron and steel continues to be produced by reducing iron ore in emission-intensive coal-fired furnaces. In cement production, more than 90% of the energy used is fuel combustion.

According to the IEA Energy Technology Perspectives, to support the goals of the Paris Agreement, the share of coal in cement production would be required to decrease from 63% in 2014 to 25% by 2060.

Overall, the share of fossil fuels is anticipated to drop from 83% to 59%, with natural gas making up 48%, compared with 11% in 2014.

Growth and decarbonisation potential of industry



This chart presents an analysis from Shell's Scenarios team of the likely growth across different sub-sectors of industry and agriculture, from 2013 until the early part of the second half of the century, and the potential to decarbonise each sub-sector. The analysis is based on both challenging and optimistic assumptions for the deployment of new technologies and efficiency improvements. The middle, blue circle represents the 2013 breakdown of total final energy consumption by light industry, agriculture (including the relatively minor roles of forestry and fishing) and the five sub-sectors of heavy industry: pulp and paper, iron and steel, non-ferrous metals, chemicals and petrochemicals, and non-metallic minerals, including cement. The production growth of each sector is indicated by the size of the coloured circles, and their colours indicate our qualitative assessment of the difficulty of decarbonising them.

Source: Shell Scenarios (Shell Scenarios are neither predictions nor forecasts of future events, rather they are designed to present plausible potential visions of the long-term future).

Chemicals

Natural gas can be used as a feedstock in the manufacture of certain base chemicals. The petrochemicals industry converts methane into ammonia, which is used in agricultural fertiliser, and into methanol, which is used in energy and construction.

Chemicals companies use ethane, the second-largest component of natural gas after methane, to make ethylene. This is first converted into performance chemicals such as polyester, higher olefins and polyethylene. In turn, they are used for a wide variety of consumer and packaging end products, including clothing, detergents, furniture, bottles and containers.

The chemicals industry is growing rapidly to support increasing standards of living. Today, oil and natural gas accounts for 75% of the global total final energy mix in the chemicals and petrochemicals subsector, including use as a feedstock and for production, according to the IEA. Coal contributes 10% worldwide, but a much higher share in China, where it makes up 32% and is used widely for ammonia and methanol production.

Natural gas, as a feedstock and for the production of chemicals and petrochemicals, has a lower carbon intensity than both oil and coal.

Carbon capture, utilisation and storage in industry

CCUS is one of the few options for reducing CO_2 emissions from energy-intensive industries, including the production of steel, cement and chemicals. These industries rely on hydrocarbon fuels to generate high temperatures essential to their industrial processes. As a result, they emit CO_2. Meeting long-term climate change ambitions will require a large and rapid increase in the number of CCUS projects. It will require significant collaboration and knowledge sharing to accelerate CCUS development. (See Electricity generation).

CASE STUDY: CARBON CAPTURE AND STORAGE ON THE NORWEGIAN CONTINENTAL SHELF

STATOIL, SHELL AND TOTAL ARE DEVELOPING A PROJECT THAT WILL CAPTURE AND STORE CO_2 FROM A CEMENT FACTORY, AN AMMONIA PLANT AND A WASTE-MANAGEMENT SITE IN EASTERN NORWAY.

The captured CO_2 will be transported by ship from the carbon capture facilities to a receiving terminal located on the west coast of Norway. At the receiving terminal, it will be transferred from the ship to intermediate storage tanks, before being sent through a pipeline on the seabed to injection wells east of the Troll gas field on the Norwegian continental shelf. The first phase of the project could store up to 1.5 million tonnes of CO_2 each year.

CHAPTER 4: **THE BUILT ENVIRONMENT**

4

The energy transition in the built environment

The main uses of energy in buildings are heating, cooling, lighting and cooking. These uses account for around 30% of the energy used globally and 55% of demand for electricity. Depending on the steps taken to improve the energy performance of buildings, demand could increase by up to 28% between 2014 and 2060. Most of this demand is expected to come from developing countries, where the total floor area of buildings is expected to double by 2060. Including emissions from the generation of electricity that they use, buildings are responsible for more than one-quarter of global energy-related CO_2 emissions today.

The role of gas in homes

In many developed countries, it is emerging practice for heating (water, space and cooking) to be powered by electricity. However, the extent of electrification will depend on how quickly existing buildings can be retrofitted. Retrofitting existing buildings across such countries could take decades. It will also require significant investment in power generation and transmission infrastructure to meet the increasing demand for electricity.

Where gas infrastructure is in place, replacing conventional natural gas-fired boilers with highly efficient natural gas-fired condensing boilers today represents a fast and cost-effective way to improve energy efficiency and reduce emissions from the use of energy in buildings. In the EU, for example, heating accounts for 27% of total energy consumption (including in houses, offices and public spaces), with gas accounting for 46% of supply.

According to a Burgeap Report for trade association Eurogas in 2014, if all existing conventional gas boilers were replaced with high-efficiency condensing boilers, the EU member states could reduce CO_2 emissions from heating by as much as 7%. In countries with existing gas infrastructure, gas can also be a cheaper source of heating than electricity. For example, in the UK gas costs up to three times less per kilowatt hour than electricity.

Highly efficient gas boilers can also support the integration of renewable energy sources, such as heat pumps, by meeting any shortfalls in demand for heat on very cold days. Such hybrid systems allow consumers to access the lowest-cost energy available. Longer term, these systems will also allow the integration of decarbonised gas, such as biogas or hydrogen.

CASE STUDY: FREEDOM PROJECT, WALES

THE FLEXIBLE RESIDENTIAL ENERGY EFFICIENCY, DEMAND OPTIMISATION & MANAGEMENT PROJECT (FREEDOM PROJECT) IS A COLLABORATION BETWEEN AN ELECTRICITY DISTRIBUTION NETWORK OPERATOR (WESTERN POWER DISTRIBUTION) AND A GAS DISTRIBUTION NETWORK OPERATOR (WALES & WEST UTILITIES).

It involves the installation of 75 hybrid heating systems in residential properties in Bridgend, Wales. The project's hybrid heating system includes an exterior air source heat pump and high-efficiency gas boiler in homes, and a control which enables switching between the two heat sources. Wales & West Utilities estimates that, if implemented across the UK, such a system could reduce the CO_2 intensity of heating by up to 50%, or more if biogas is used.

In developing countries, traditional biomass such as wood, dung and peat still meets 43% of energy demand in homes. Replacing these fuel sources with cleaner-burning natural gas eliminates the impact of high levels of indoor air pollution. In India alone, where around 700 million people still rely on solid fuels for domestic cooking, exposure to household solid fuels is estimated to cause 500,000 premature deaths and 5 million illnesses each year.

Distributed energy systems

Distributed energy is generated at or near the point of use. Relative to traditional centralised electricity generation, distribution and transmission, distributed energy systems can improve efficiency and reduce emissions of greenhouse gases and air pollutants.

An increase in distributed electricity generation is being driven by the need to overcome technical planning and financial challenges associated with centralised power and the transmission and distribution of electricity. This is particularly true in developed countries where there are often complicated planning processes and local resistance to overhead transmission lines. In countries with less developed infrastructure, such as China and India, distributed power provides fast and simplified access to energy.

In recent years, the cost of distributed energy has come down significantly and smaller, modular energy systems require less upfront investment than centralised power. This allows cities to plan smaller-scale investments instead of more complex and expensive infrastructure projects. In addition, distributed energy systems allow cities to increase power supply incrementally to meet demand.

Policies designed to support an increasing role for distributed power are also creating more demand for natural gas. These policies recognise the role that natural gas can play in reducing emissions of greenhouse gases and air pollution, compared to coal.

District heating

District heating (also known as district heat networks) is a system for distributing heat generated in a centralised location for residential and commercial heating needs, such as space heating and water heating in buildings. The heat is distributed to where it is needed through a network of insulated pipes. Gas-fired district heating offers efficiency and environmental benefits, particularly when coal-fired boilers are converted to gas.

In China, the Ministry of Environmental Protection has implemented a plan to reduce air pollution in Beijing, Tianjin and 26 smaller cities in the north of China. Hundreds of thousands of homes have already been connected to new gas heating systems. Across China, coal to gas switching in the residential and commercial sector could add around 32 billion cubic metres (bcm) to China's gas use between 2016 and 2020, compared to total demand of around 206 bcm in 2016.

> THE COST OF DISTRIBUTED ENERGY HAS COME DOWN SIGNIFICANTLY

CASE STUDY: DISTRICT HEATING COMBINED HEAT AND POWER, ORADEA MUNICIPALITY, ROMANIA

IN THE ORADEA MUNICIPALITY IN ROMANIA, A COAL DISTRICT HEATING SYSTEM REPLACED BY A GAS-FIRED COMBINED HEAT AND POWER SYSTEM HAS INCREASED ENERGY EFFICIENCY BY 20%, CUT FUEL CONSUMPTION BY 23% AND REDUCED CO_2 EMISSIONS BY MORE THAN 200,000 TONNES EACH YEAR. THE HEAT IS USED TO PROVIDE RELIABLE HEATING AND HOT WATER TO 200,000 INHABITANTS.

Combining heat and power

Combined heat and power (CHP) systems (also known as cogeneration) are efficient, integrated energy technologies that generate electricity and heat close to where there are major centres of demand, such as towns and cities. A large share of energy is lost during conventional power generation. CHP units running on natural gas integrate the production of heat and power in a single, highly-efficient process.

The waste heat can be used to generate additional power, or be directed to nearby consumers in the form of steam or hot water via a short pipeline network. Waste heat can also be used in air conditioning units to meet the cooling requirements of buildings. This is also referred to as trigeneration. City planning that incorporates infrastructure to accommodate distributed gas-fired CHP generation helps to reduce emissions of greenhouse gases and air pollution, particularly when compared with the use of coal or diesel.

A combination of gas-fired district heating with gas-fired CHP is a highly efficient and cost-effective way to reduce CO_2 emissions and air pollution. For example, a combination of CHP and centralised heat pumps used in Stockholm, the capital of Sweden, allows the production of heat using surplus electricity from renewables, with gas-fired power generation and district heating being used when renewable power is insufficient.

The use of natural gas-fired CHP can also support the integration of low-emissions sources of energy, including geothermal heat and power, solar, wind and batteries.

NATURAL GAS | THE BUILT ENVIRONMENT

CASE STUDY: COMBINED HEAT AND POWER, ROPPONGI HILLS, TOKYO

ROPPONGI HILLS IS ONE OF JAPAN'S LARGEST INTEGRATED PROPERTY DEVELOPMENTS, LOCATED IN THE ROPPONGI DISTRICT OF MINATO, TOKYO.

The large complex incorporates office space, apartments, shops, restaurants, cafés and movie theatres, along with a museum, hotel, major TV studio, outdoor amphitheatre, and several parks. The Mori Building Tower has a natural gas CHP unit, which supplies electricity, heating and cooling to the whole area. The highly efficient system reduces energy consumption by 20% compared to centralised power generation. In turn, this cuts CO_2 and nitrogen oxides by around 20% and 40% respectively.

CASE STUDY: K.I.E.L. COASTAL POWER PLANT, GERMANY

THE MUNICIPAL UTILITY STADTWERKE KIEL IS DEVELOPING A LARGE-SCALE GAS-POWERED COGENERATION PLANT IN GERMANY THAT WILL PROVIDE HIGH-EFFICIENCY HEAT AND POWER.

Compared to the coal-fired power plant that it will replace, CO_2 emissions are expected to be reduced by more than 70%.

Increasing city resilience

An increasing dependence on the infrastructure networks that deliver the energy people need leaves communities increasingly vulnerable to supply disruptions, such as those caused by natural disasters. In the USA, for example, where the electricity grid is 99.97% reliable, disruptions caused by bad weather, human error, animal interference or mechanical failure cost at least $150 billion in economic losses each year, according to the US Department of Energy. Resilient energy systems are critical to prepare for and reduce the impact of these disruptions, particularly in cities.

Gas-fired CHP systems strengthen the resilience of cities, providing backup power when the main grid is down. This was demonstrated when Hurricane Sandy hit the East Coast of the USA in 2012. Power disruptions affected 8.5 million people and left more than 1.3 million without electricity for a week. However, a gas-fired microgrid system at Long Island, New York, continued to generate electricity for 15 days, providing power to the North Shore Health System facility and 400 homes.

Power to gas: the promise of hydrogen

In countries with existing gas infrastructure, hydrogen (produced by steam methane reforming of natural gas, or through electrolysis using solar or wind power) can be combined with natural gas and used in power generation, or injected into a distribution network for use in buildings. This is sometimes referred to as 'power to gas'. Today, most hydrogen is produced from natural gas. In the long term, hydrogen produced from renewables offers a storage solution for excess energy produced by variable renewables.

A report by KPMG, an audit, tax and advisory company, which explores the role of UK gas networks up to 2050, has shown that making use of the UK's existing gas network could provide a practical and affordable way to reduce emissions from heating. The report shows that a combination of natural gas, biogas and hydrogen offers the lowest-cost emissions reduction pathway for the UK's heating needs, saving the country up to $280 billion and consumers up to $12,350 each between 2015 and 2050. It is also shown to be the most technically feasible and socially acceptable option.

CHAPTER 5: **TRANSPORT**

5

The energy transition in transport

Transport is essential to modern living. It drives economic growth, allowing countries to trade goods and communities to connect with one another. A growing and more prosperous global population will significantly increase demand for transport, for both personal mobility and the transport of goods. Meeting this demand while reducing emissions will require continued innovation.

Today, transport accounts for 28% of global final energy demand. Even with significant energy efficiency improvements and a greater proportion of the world's population living in more compact cities, transport demand could increase by 46% by 2060, according to the IEA.

Satisfying increasing demand must be balanced with efforts to reduce greenhouse gas emissions, which contribute to climate change. Between 2010 and 2015, greenhouse gas emissions from transport increased by an average of 2.5% each year. Today, it is responsible for 23% of total global greenhouse gas emissions. Transport can also contribute to poor air quality, resulting in negative effects on the environment and human health.

Today, the transport sector is almost entirely powered by internal combustion engines fuelled with liquid hydrocarbons. This includes petrol and diesel in cars and fuel oil in ships. Improvements in the efficiency of these engines, in combination with lower sulphur fuels, have delivered considerable fuel savings and contributed to reductions in air pollution.

To meet increasing demand for transport with even fewer emissions, a mosaic of transport solutions will be required, including new lower-emissions fuels. This will include lower-emissions liquid fuels, biofuels and natural gas. It will also include new drivetrains and an increasing role for electric vehicles powered by both batteries and hydrogen fuel cells.

Natural gas will also have a significant role to play. Energy use in transport is expected to increase most in long-distance transport modes between 2015 and 2060, according to the IEA. In ships and trucks – where the size, weight and range of batteries currently limit their potential, natural gas could be an effective way to reduce air pollution and greenhouse gas emissions. The IEA estimates that use of natural gas for transportation could grow by as much as 14% between 2016 and 2022.

An effective transition in the transport sector will require a coordinated approach and policies that recognise the relationship between vehicles, fuels, refuelling infrastructure and consumer choice.

TRANSPORT ACCOUNTS FOR 28% OF GLOBAL FINAL ENERGY DEMAND

LNG for transport

LNG is emerging as a cost-competitive and cleaner-burning fuel for shipping and heavy-duty road transport. In the future, it could also be used for freight rail.

Realising the environmental benefits of LNG as a fuel will require collaboration across government and industry – growing infrastructure, supporting standards for emissions controls, and providing incentives that encourage demand growth for lower emissions fuels. This will be particularly important in the marine sector, which is subject to a complex regulatory environment with overlapping regional jurisdictions.

LNG for trucking

The IEA estimates that by 2060, 36% of additional energy demand for transport will come from road freight vehicles, particularly in East and South-East Asia. In 2015, China, India and countries in South-East Asia accounted for 30% of tonne kilometres (a measure of freight carried by a mode of transport) by road. This could increase to 46% by 2060.

In Africa, the share of trucking activity is expected to double by the end of the century.

Switching heavy-duty vehicles to LNG diversifies the fuel mix and can help reduce harmful air pollution. These benefits are helping to support demand in countries such as China, where there are already more than 200,000 heavy-duty trucks and buses on the road, refuelling at more than 2,000 LNG filling stations according to Sublime China Information. The number of LNG trucks is growing quickly, with sales of LNG heavy-duty trucks accounting for around 5% of total sales.

From extraction to use, LNG can reduce greenhouse gas emissions by up to 6% compared with diesel, according to a Thinkstep study for the Natural Gas Vehicle Association. Using the latest high pressure direct ignition engine, greenhouse gas reductions can be up to 15% lower, according to the study. LNG engines are also quieter than those using diesel. This is an advantage for urban areas, particularly for deliveries at night or areas subject to high traffic volumes.

How does LNG for transport work?

Once natural gas has been liquefied, the LNG is kept in insulated tanks until it is loaded into a specially designed ship or carrier. When it reaches its destination, LNG is offloaded into storage tanks at a facility known as a break-bulk terminal. This is used by supply barges, ferries, cruise liners, container ships and tankers in ports, rivers and coastal areas. Natural gas can also be liquefied on a small scale, which makes it even more accessible.

This approach uses liquefication plants built in sections so they can be scaled up and down and moved to different locations. Trains and tankers carry LNG to storage tanks at fuelling stations for large trucks. Once there, the LNG is kept cool in insulated tanks. Customers fill up the vehicles in just the same way as they would with other liquid fuels.

Vehicles that run on LNG can also be fuelled by biomethane, which is chemically and physically identical to the methane found in natural gas. When produced from organic waste, such as municipal waste, agricultural residues and manure, the use of biomethane can lead to lower greenhouse gas emissions, particularly when the methane used would otherwise be released into the atmosphere, such as at waste management or dairy sites.

Biomethane can be used directly in LNG fuel trucks, offering benefits to fleets with hub-and-spoke operations (a system of connections arranged like a wire wheel in which all traffic moves along spokes) and refuelling infrastructure close to biomethane production sites.

LNG for trucks
Used in trucks delivering goods, LNG can reduce sulphur emissions, particulates and nitrogen oxides, and help reduce greenhouse gas emissions from production to use, compared to conventional diesel. It also has the potential to offer savings on fuel costs.

LNG for shipping

Around 80% of world trade in goods is by ship. This trade is expected to increase by nearly 50%, between 2017 and 2030. Today, there are limited alternatives to hydrocarbons to fuel ships, which still mainly run on heavy fuel oil and diesel.

The global shipping fleet produces air pollution, which impacts the environment and human health. Around 70% of these emissions occur within 400 kilometres of coastal communities – mainly in East Asia, South Asia and Europe.

The International Maritime Organization has made progress in agreeing to limit sulphur oxide and nitrogen oxide emissions from ships. LNG fuel can help ship operators meet these requirements. Compared to heavy fuel oil, natural gas combustion produces up to 80% less nitrogen oxides, which can help reduce smog formation.

Natural gas emits virtually no sulphur dioxide, so using more natural gas as fuel would emit less of the pollutants that cause acid rain. LNG also has a lower unit cost compared with low-sulphur heavy fuel oil or low-sulphur diesel fuel.

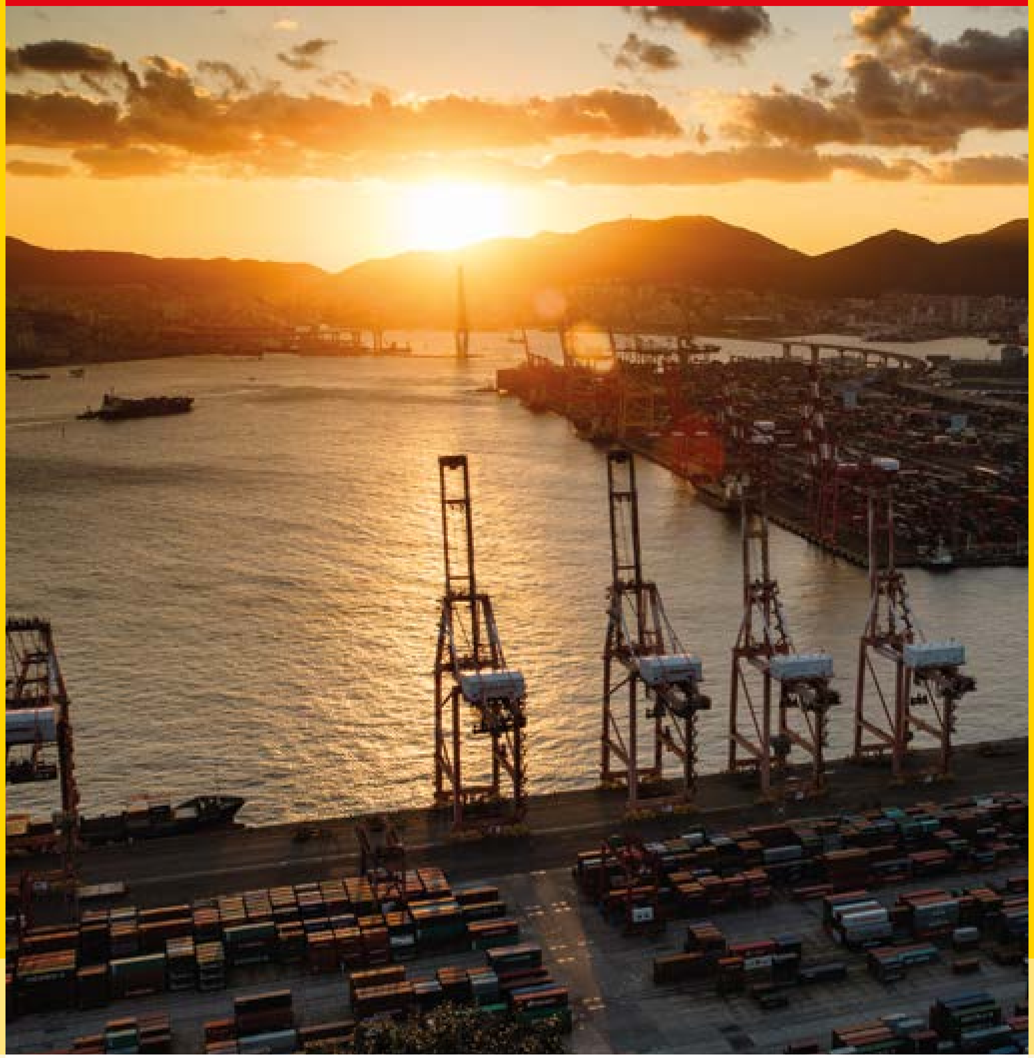
Shipping also produces greenhouse gas emissions. Although it is an efficient means to transport cargo over long distances, the scale of activity generates significant total emissions, with more than 50,000 merchant ships operating internationally. Switching from heavy fuel oil to LNG can reduce greenhouse emissions by up to 21% in a two-stroke engine with high-pressure injection and by 11% in a four-stroke engine, according to the Thinkstep study. This may become an increasingly important consideration for ship operators with the development of more stringent international emissions standards over the next decade.

Carnival Corporation, the world's biggest cruise operator, has commissioned two cruise ships that will run on LNG in northern Europe and the western Mediterranean from 2019.

North American Emissions Control Area

The North American Emissions Control Area (ECA) came into effect in 2012. It includes the US Pacific, Atlantic and Gulf coasts, Hawaiian Islands, St. Lawrence Seaway, Great Lakes and those rivers accessible to international shipping. By 2030, emissions from ships operating in these areas are expected to be reduced each year by 1,300,000 tonnes for sulphur oxide, 1,200,000 tonnes for nitrogen oxide and 143,000 tonnes for particulate matter, according to the US Environmental Protection Agency (EPA). The EPA estimates that this could prevent 12,000 to 31,000 premature deaths, and relieve respiratory symptoms for nearly 5 million people each year in the USA and Canada. The health-related benefits to the USA are valued by the EPA at $110 to $270 billion by 2030.

CASE STUDY: BUSAN PORT, SOUTH KOREA



BUSAN PORT PROVIDES A LOGISTICS HUB FOR NORTHEAST ASIA, CONNECTING CONTAINER TRAFFIC FROM 500 PORTS IN 100 COUNTRIES.

The port is rapidly growing to support increasing demand. In response to concerns about local air pollution in the port area, with the support of the Korean government, the port authorities are converting their ground transport fleet from diesel to LNG.

NATURAL GAS | TRANSPORT

Gas-to-liquids fuels

Natural gas is also converted into high-quality liquid transport fuels using a technology called the Fischer Tropsch process. Gas-to-liquids (GTL) fuel is a cleaner-burning alternative to diesel that can be used in existing heavy-duty and light-duty diesel engines as a drop-in fuel without the need for engine modifications, new infrastructure or vehicle investment. GTL fuel will play an increasingly important role in the fuel mix for heavy-duty vehicles, inland and seagoing marine vessels, rail and aviation ground fleets, particularly in regions seeking to improve local air emissions.

Compressed natural gas

Compressed natural gas (CNG) can be used in light- and heavy-duty vehicles and may emit fewer greenhouse gases and air pollutants than liquid fuels. For passenger cars, from the point where gas is extracted to when it is used in a car, CNG reduces greenhouse gas emissions by up to 23% compared with petrol and up to 7% compared with diesel, according to the Thinkstep study. For heavy-duty vehicles, CNG cuts greenhouse gas emissions by up to 16% compared to diesel. CNG also emits up to 58% less nitrogen oxide and up to 97% less particulate matter than diesel. Converting to CNG requires an upfront capital investment from vehicle owners. Where CNG costs less than liquid fuels, owners often recoup their investment over the lifetime of the vehicle.

GTL fuel, The Netherlands
Groningen chose to switch its municipal vehicles to GTL fuel to help improve the city's local air quality. Vehicles include garbage trucks, street cleaners, vans, all-terrain-vehicles and tractors.

CASE STUDY: CNG IN DELHI, INDIA

INDIA IS HOME TO THE WORLD'S SIXTH-LARGEST FLEET OF NATURAL GAS-FUELLED VEHICLES, INCLUDING CNG-POWERED TAXIS AND BUSES.

In response to air pollution, Delhi was one of the first cities to mandate a shift from diesel to natural gas. This approach has significantly lowered emissions and improved air quality in many cities across India. Continued switching from diesel to CNG could contribute to a nine-fold increase in demand for gas to power India's transport sector by 2040.

THE FUTURE OF NATURAL GAS

Energy powers progress. Meeting increasing global demand while minimising negative impacts on the planet and the air we breathe is one of the greatest challenges of the 21st century.

A transformation of the global energy system is needed. It will take place at different paces in different countries, depending on factors such as available natural resources and national policies designed to address climate change and local air quality.

Natural gas will be a critical component of this energy transition – to generate electricity, provide heat for essential industrial processes, heat or cool homes, and transport people and goods over long distances.

Switching from coal to cleaner-burning natural gas is significantly reducing greenhouse gas emissions and air pollution today.

The flexibility of natural gas will continue to support the integration of variable renewable electricity, cost-effectively responding to increases in demand and drops in supply from solar, wind and hydro.

An increasing share of electricity generated from renewables will drive greater use of electricity across industry, the built environment and transport.

Electricity generation is expected to increase from a fifth of energy use today to 50% by 2050. As the share of renewable electricity increases, the flexibility of natural gas will make it increasingly competitive with other thermal power generation, such as coal.

Natural gas will also be vital in parts of the economy that are more difficult to electrify, including industrial processes and freight transport.

Economics, government policies and relative environmental benefits will shape the future role of natural gas.

The economics will become more competitive when government policies consider not only the cost of purchasing and using fuel, but also the anticipated costs associated with the impacts on the environment and human health.

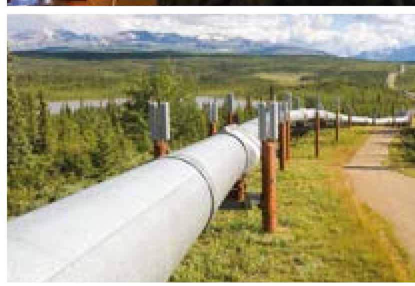
Government policies that put a price on carbon emissions can help reduce emissions and encourage investment in cleaner energy sources. Likewise, government-led emissions standards can drive investment and accelerate emissions reductions.

The natural gas industry must continue to prioritise safety, environmental safeguards and engagement with local communities.

A priority is to monitor and reduce methane emissions across the value chain, to realise the significant climate benefits compared to higher-carbon fuels.

Together, natural gas and renewables offer reliable, flexible and cost-effective access to more and cleaner energy.


shell.com/roleofnaturalgas



LNG INFORMATION PAPER

#1

2019 Update

Basic Properties of LNG

contents

GIIGNL's Technical Study Group introduces a series of Information Papers that provide factual information about Liquefied Natural Gas (LNG). This paper begins with a review of basic properties of LNG, which is a pre-requisite for accurately assessing potential LNG safety hazards and risks.

INTRODUCTION

A basic knowledge of LNG must begin with an examination of its chemical and physical properties because the properties that make LNG a good source of energy can also make it hazardous if not adequately contained. These properties determine how LNG behaves, inform our predictions about its behaviours, and influence how we assess and manage safety risks. Furthermore, to accurately understand and predict LNG behaviour, one must clearly distinguish its properties as a liquid from its properties as a gas or vapour.

The reader will note that discussions of the properties of LNG often contain ominous caveats like "depending upon its exact composition". This is because such specifics matter and universal generalisation about LNG are often inexact and inappropriate. Inaccurate information about the properties of LNG that influence potential safety hazards can lead to misunderstanding and confusion. For example, when thinking through how LNG would behave if accidentally or intentionally released (e.g. from a terrorist attack), the outcome will be profoundly influenced by the actual situation and site-specific conditions.

Misunderstanding LNG is not uncommon and is often caused by confusion, incomplete, or inaccurate information about LNG properties. Since properties determine behaviour and influence how we manage potential safety hazards and risks, having an accurate understanding is key.

A number of LNG companies have made commitments to educate the general public about their product Companies in Japan and South Korea have gone to great lengths to share information about their facilities with the local communities and to educate them about LNG. For example, Osaka Gas Company and Tokyo Gas Company have installed Gas Science Museums at each of their terminals; the first one opened in 1982. More than 50,000 children, among other visitors, tour the museums every year and are able to observe table-top demonstrations of LNG properties and behaviours.

LNG is natural gas which has been converted to liquid form for ease of storage or transport. LNG takes up about 1/600th of the volume of natural gas. Depending upon its exact composition, natural gas becomes a liquid at approximately -162°C (-259°F) at atmospheric pressure.

LNG's extremely low temperature makes it a cryogenic liquid. Generally, substances which are -100°C (-148°F or less) are considered cryogenic and involve special technologies for handling. In comparison, the coldest recorded natural temperatures on earth are -89.4°C (-129 °F) at the height of winter in Antarctica and the coldest reported temperature in a town was recorded in Oymyakon (Sakha Republic) during Siberian winter (-71.2°C; -96.16 °F). To remain a liquid, LNG must be kept in containers which function like thermos bottles – they keep the cold in and the heat out. The cryogenic temperature of LNG means it will freeze any tissue (plant or animal) upon contact and can cause other materials to become brittle and lose their strength or functionality. This is why the selection of materials used to contain LNG is so important.

LNG is odourless, colourless, non-corrosive, non-flammable, and non-toxic. Natural gas in your home may have been liquefied at some point but was converted into its vapour form for your use. It may also have a smell due to an odorising substance added to natural gas before it is sent into the distribution grid. This odour enables gas leaks to be detected more easily.

Key liquid and gas properties for LNG are:

- Chemical Composition,
- Boiling Point,
- Density and Specific Gravity,
- Flammability

These properties are listed on Material Safety Data Sheets (MSDS's).

CHEMICAL COMPOSITION

Natural gas is a fossil fuel, meaning it has been created by organic material deposited and buried in the earth millions of years ago. Crude oil and natural gas constitute types of fossil fuel known as "hydrocarbons" because these fuels contain chemical combinations of hydrogen and carbon atoms. The chemical composition of natural gas is a function of the gas source and type of processing. It is a mixture of methane, ethane, propane and butane with small amounts of heavier hydrocarbons and some impurities, notably nitrogen and complex sulphur compounds and water, carbon dioxide and hydrogen sulphide which may exist in the feed gas but are removed before liquefaction. Methane is by far the major component, usually, though not always, over 85% by volume. **Table 1** displays the chemical compositions of the hydrocarbon compounds which make up natural gas, and the volume ranges in which they may be present in LNG. Pipeline natural gas may contain small amounts of water vapour.

Table 1. Examples of LNG composition

Origin	Nitrogen (N_2X)	Methane (CH_4) C1 %	Ethane (C_2H_6) C2 %	Propane (C_3H_8) C3 %	Butane (C_4H_{10}) C4+ %	Gas GCV MJ/m³ (n)	Wobbe Index MJ/m³ (n)
Australia NWS	0.04	87.33	8.33	3.33	0.97	45.32	56.53
Malaysia Bintulu	0.14	91.69	4.64	2.60	0.93	43.67	55.59
Nigeria	0.03	91.70	5.52	2.17	0.58	43.41	55.50
Qatar	0.27	90.91	6.43	1.66	0.74	43.43	55.40
Trinidad	0.01	96.78	2.78	0.37	0.06	41.05	54.23

(Source: 2018 Annual Report, GIIGNL)

Due to its chemical composition, natural gas is the cleanest burning hydrocarbon, which offers a considerable chance to reduce CO_2 emissions. It produces the least CO_2 of all fossil fuels because of its high heating value, low carbon content and efficient combustion. When natural gas is used for electricity generation, it produces 45-55% less greenhouse gas (GHG) emissions than coal and 20% less than oil. Natural gas is also one of the keys to solve the global air pollution problem as it emits virtually no sulphur or particles.

LNG is often confused with liquefied petroleum gas (LPG), which in turn is often incorrectly identified as propane. In fact, LPG is a mixture of mainly propane and butane gases that exist in a liquid state at ambient temperatures when under moderate pressure (less than 1.5 MPa or 200 psi). In the U.S., Canada, and Japan, LPG consists primarily of propane (**Table 2**). However, in many European countries, the propane content in LPG can be as low as 50% or less. Moreover, in some countries, LPG may contain a substantial portion of propylene.

LPG's differing composition and physical properties (from LNG) make its behaviour different as well. The propane and butane in LPG have different chemical compositions from methane, the primary hydrocarbon in natural gas and LNG. Propane and butane can be stored and transported as a mixture, or separately. Both are gases at normal room temperature and atmospheric pressure, like methane, readily vaporising. Propane liquefies much more easily than LNG (at -43°C [-46 °F] vs. -162°C [-259 °F] for LNG) so it is substantially easier to compress and carry in a portable tank. In fact, LPG is stored as a liquid under pressure at ambient (room) temperatures, whereas LNG is stored as a liquid only at very low temperatures and ambient pressure.

Table 2. Typical composition of LPG in % by volume

Country	Propane	Butane
Belgium	50	50
France	35	65
Ireland	100*	100*
Italy	25	75
Germany	90	10
UK	100*	100*
Denmark	50	50
Greece	20	80
Netherlands	50	50
Spain	30	70
Sweden	95	5

** NOTE: In Ireland and the U.K., LPG may be 100% of either basic gas.*

BOILING POINT

Boiling point is one of the most significant properties because it defines when gas becomes a liquid. Merriam-Webster online (www.merriam-webster.com) defines "boiling point" as "the temperature at which a liquid boils" or at which it converts rapidly from a liquid to a vapour or gas at atmospheric pressure. The boiling point of pure water at atmospheric pressure is 100°C (212 °F). The boiling point of LNG varies with its basic composition, but typically is -162°C (-259 °F).

When cold LNG comes in contact with warmer air, water, or the environment, it begins to "boil" at that interface because the surrounding temperatures are warmer than the LNG's boiling point, as shown in **Figure 1. Table 3** shows the boiling points of water and common gases.

The liquefaction process cools natural gas to a temperature below its boiling point, changing it to a liquid with a volume approximately 600 times lower than that occupied by the gas. Before distribution to industrial and residential consumers LNG is converted back into natural gas (regasified) by warming it back above its boiling point.

Figure 1. LNG "boiling" at atmospheric pressure and temperature *(Source: OSAKA Gas)*

Table 3. Boiling points of water and some common gases

Fahrenheit (degrees F)	Celsius (degrees C)	Occurrence
212	100	Water Boils
31	-0.5	Butane Boils
-27	-33	Ammonia Boils
-44	-42	Propane Boils
-259	-162	LNG Boils
-298	-183	Oxygen Boils
-319	-195	Nitrogen Boils
-422	-252	Hydrogen Boils
-454	-270	Helium Boils
-460	-273	Absolute Zero

(Source: Adapted from the Engineering Toolbox online, www.engineeringtoolbox.com/boiling-points-fluids-gases-d_155.html)

NOTE: Absolute zero is the coldest temperature theoretically possible, and cannot be reached, by artificial or natural means. By international agreement, absolute zero is defined as precisely 0 K on the Kelvin scale and is equivalent to -273.15°C/-459.67 °F.

DENSITY AND SPECIFIC GRAVITY

Density is a measurement of mass per unit of volume and is an absolute quantity. Because LNG is not a pure substance, the density of LNG varies slightly with its actual composition. The density of LNG falls between 420 kg/m^3 and 470 kg/m^3 (3.5 to 4 lb/US gal). LNG is less than half the density of water; therefore, as a liquid, LNG will float if spilled on water.

Specific gravity is a relative quantity. The specific gravity of a liquid is the ratio of density of that liquid to density of water (at 15.6°C/60°F). The specific gravity of a gas is the ratio of the density of that gas to the density of air (at 15.6°C). Any gas with a specific gravity of less than 1.0 is lighter than air (buoyant). When specific gravity or relative density is significantly less than air, a gas will easily disperse in open or well-ventilated areas. On the other hand, any gas with a specific gravity of greater than 1.0 is heavier than air (negatively buoyant). The specific gravity of methane at ambient temperature is 0.554, therefore it is lighter than air and buoyant.

Under ambient conditions, LNG will become a vapour because there is no place on earth with a temperature of -162°C (-259 °F). As LNG vaporises, the cold vapours will condense the moisture in the air, often causing the formation of a white vapour cloud until the gas warms, dilutes, and disperses as shown in **Figure 2**.

Figure 2. LNG Vapour Cloud created at ENGIE Lab CRIGEN LNG testing facility *(Source: Engie Lab)*

For a relative humidity of higher than 55%, the flammable cloud is totally included in the visible vapour cloud. If the relative humidity is less than 55%, the flammable cloud can be partially or completely outside of the visible cloud, which means that the vapours could be ignited even though the ignition source is distant from the visible vapour cloud. The size of the vapour cloud will depend on wind speed, direction, and other weather conditions and can easily be predicted by the appropriate related calculations. These very cold vapours will rise as they are sufficiently warmed by ambient air.

LNG vapours at the boiling point temperature (-162°C/-259 °F) and atmospheric pressure have a relative density of about 1.8, which means that when initially released, the LNG vapours are heavier than air and will remain near the ground. However as methane vapours begin to rapidly warm and reach temperatures around -110°C/-166 °F, the relative density of the natural gas will become less than 1 and the vapours become buoyant.

At ambient temperatures, natural gas has a specific gravity of about 0.6, which means that natural gas vapours are much lighter than air and will rise quickly. Cold LNG vapours (below -110°C/-166 °F) are negatively buoyant and more likely to accumulate in low areas until the vapours warm. Therefore, a release of LNG that occurs in an enclosed space or low spot will tend to replace the air (and oxygen) and make the area a hazard for breathing.

The rate of LNG vapour ascent depends upon the quantity of LNG released, ambient weather conditions, and where the LNG is released, e.g., confined or unconfined, low or elevated area, on land or on water. One strategy to manage the vapours is to create a downwind water curtain which helps block and/or divert the vapours away from possible ignition sources until the vapours warm and become buoyant, and/or dilute to a lesser concentration outside the flammable limits, which are discussed in the next section.

Heat input to LNG in any form will enhance vaporisation and dispersion. Such heat may be transferred from passive sources such as atmospheric humidity (which is a significant source), the ground or spill catchment areas, impoundments, pits and structures. LNG vaporises up to five times more quickly on water than on land, depending upon the soil condition. In fact, another strategy for managing the flammability hazard of LNG vapours is to use a water hose to warm the liquid more quickly (while avoiding contact with the super-cold LNG), increase vaporisation rates, and make the vapours buoyant sooner, rising away from ignition sources at ground level.

FLAMMABILITY

Flammability is the property which makes natural gas desirable as an energy source, and yet for the same reason flammability can be a safety hazard. It is very important to be clear: natural gas is flammable but LNG (the liquid form of natural gas) is not because of the lack of oxygen in the liquid. Since LNG begins vaporising immediately upon its release from a container, the important issue is: when will the vapours be flammable and for how long?

Flammability Limits

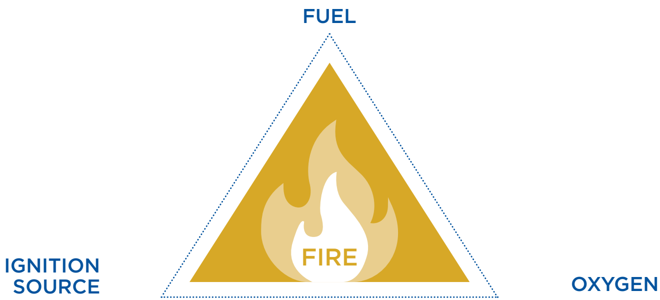
Three things are needed to support a fire:

- A source of fuel (e.g., flammable gas or vapour),
- Air (oxygen), and
- A source of ignition (e.g., spark, open flame, or high-temperature surface).

This is known as the fire triangle (**Figure 3**). Several factors are required to start a fire from LNG vapours. In particular, the fuel and the oxygen have to be in a specific range of proportions to form a flammable mixture.

Figure 3. The fire triangle

This “Flammable Range” is the range of a concentration of a gas or vapour that will burn if an ignition source is introduced. The limits are commonly called the «Lower Flammability Limit» (LFL) and the «Upper Limit» (UFL) (**Figure 4**).



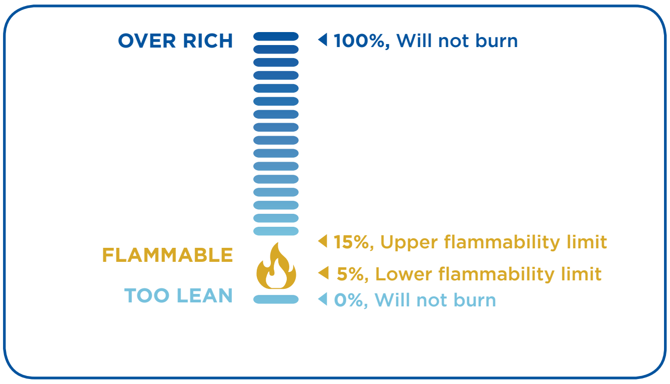


Figure 4. Flammability range for methane

(Source: Foss 2003)

The LFL for methane is 5% and the UFL is 15% both by volume in air. Outside of this range, the methane/air mixture is not flammable. **Table 4** shows flammability limits for methane compared with other fuels. Many materials around us are flammable and it is important to be aware of each substance's flammability limits to assure safe handling and use. Materials that have wide flammable ranges make them dangerous to emergency responders because there is a longer time that they are within the flammable limits. For example, hydrogen and acetylene have a very wide range and acetylene can burn whenever vapours are from just over 2% to over 80% in air.

In a closed storage tank or vessel, the percentage of methane is essentially 100% (mostly liquid and some vapours). Any small leak of LNG vapour from a tank in a well-ventilated area is likely to rapidly mix and quickly dissipate to lower than 5% methane in air. Because of the rapid mixing, only a small area near the leak would have the necessary concentration to allow the fuel to ignite. All LNG terminals use several types of equipment on and around the storage tanks and piping throughout the facility to detect any unlikely leakages and combustible gas mixtures. This safety equipment is described in Information Paper No. 6.

Table 4. Flammability limits of hydrocarbon fuels

Fuel	LFL %	UFL %
Methane	5.0	15.0
Butane	1.86	7.6
Kerosene	0.7	5.0
Propane	2.1	10.1
Hydrogen	4.0	75.0
Acetylene	2.5	>82.0

(Source: NPFA Fire Protection Handbook)

Ignition and Flame Temperatures

The ignition temperature, also known as auto-ignition temperature, is the lowest temperature at which a gas or vapour in air (e.g. natural gas) will ignite spontaneously without a spark or flame being present. This temperature depends on factors such as air-fuel mixture and pressure. In an air-fuel mixture of about 10% methane in air, the auto-ignition temperature is approximately 540°C (1,000°F). Temperatures higher than the auto-ignition temperature will cause ignition after a shorter exposure time to the high temperature. **Table 5** shows the auto-ignition temperature of some common fuels, indicating that diesel oil and gasoline will auto-ignite at substantially lower temperatures than LNG.

Table 5. Auto-ignition temperature of some fuels at standard conditions

	NATURAL GAS	DIESEL OIL	GASOLINE
Auto-ignition temperature	599°C	260-371°C	226-471°C

(Source: BV 2009)

The precise auto-ignition temperature of natural gas varies with its composition. If the concentration of heavier hydrocarbons in LNG increases (e.g., the methane portion of the natural gas begins to evaporate or be removed from the mix), the auto-ignition temperature decreases. In addition to ignition from exposure to heat, the vapours from LNG can be ignited immediately from the energy in a spark, open flame, or static electricity when they are within the flammable limits.

LNG has a very hot flame temperature. Simply stated it burns quickly and is a better heat source than other fuels, e.g., gasoline. The methane in LNG has a flame temperature of 1,330°C (2,426 °F). In comparison, gasoline has a flame temperature of 1,027°C (1,880 °F), which means LNG burns hotter. Also, LNG burns quickly, at a rate of about 12.5 m^2/minute, compared to gasoline's burn rate of 4 m^2/minute. LNG produces more heat when burning because its heat of combustion is 50.2 MJ/kg (21,600 Btu/lb), compared to that of gasoline which has a heat of combustion of 43.4 MJ/kg (18,720 Btu/lb). The combustion of LNG produces mainly carbon dioxide and water vapour. The radiant heat of an LNG fire is a frequent safety concern of government regulators and officials, and of the public.

KEY POINTS AND CONCLUSIONS

In closing, the key points of the first information paper are:

1. First, and most importantly, one must understand that those properties which make LNG a good source of energy can also make it hazardous if not adequately contained. While LNG is predominately methane (about 85%-99%), its composition also includes small amounts other hydrocarbons. The specific chemical composition of natural gas is a function of the gas source and type of processing. The chemical composition of the natural gas and the properties of its hydrocarbon components determine how LNG behaves, affect our predictions about its behaviours, and influence how we assess and manage safety risks. Misunderstanding LNG is not uncommon and is often caused by confusion, incomplete or inaccurate information about LNG properties. One also must clearly distinguish its properties as a liquid from its properties as a gas or vapour.

2. LNG, the liquid form of natural gas, is a fossil fuel, like crude oil or other hydrocarbon-based forms of energy and products.

3. The "boiling point" of LNG is -162°C; -259 °F, which is considered a cryogenic temperature. At this temperature (somewhat depending upon its actual composition), LNG evaporates to convert from a liquid to a vapour.

4. Conversely, LNG becomes a liquid at these cryogenic temperatures (-162°C; -259 °F) at atmospheric pressure. As a liquid, it takes up about 1/600th the volume of natural gas. Consequently, it is generally transported and stored in a liquid state.

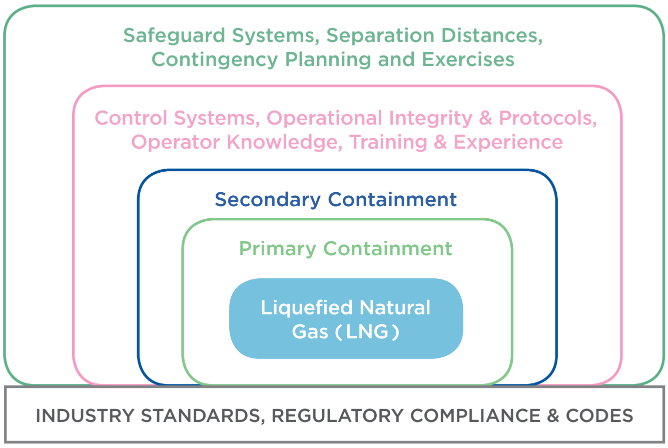
5. LNG is odourless, colourless, non-corrosive, non-flammable and non-toxic.

6. While natural gas is flammable, LNG is not. The flammability limits of methane are such that any small leak of LNG vapour from a tank in a well-ventilated area is likely to rapidly mix with air and quickly dissipate. Large leaks and spills are essentially precluded by a plethora of leak-detection systems and similar safeguards (which are discussed in later papers).

In summary, the basic properties and behaviours of LNG warrant that it be considered as a desirable option which can be managed safely when evaluating the mix of energy sources.

Subsequent papers in this series will include a discussion of the many ways in which LNG safety is assured, through Multiple Safety Layers, all firmly based on a foundation of solid Industry Standards, Regulatory Compliance and Codes. These "safety layers" include several key components of the industry's Risk Management framework. Included among them are Primary and Secondary Containment, Control Systems which promote Operational Integrity; Protocols, Operator Knowledge and Experience (which are reinforced by comprehensive and ongoing training). A protective umbrella of Safeguard Systems, Separation Distances, and Contingency Planning further enhances safe management of LNG. A graphic illustration of these "Multiple Safety Layers" is reflected in the figure below.

Multiple Safety Layers Manage LNG Risk



For more information about these and other topics, or to obtain copies of this report series contact:

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LNG INFORMATION PAPER

#6

Managing LNG Risks
Industry Safeguard Systems

2019 Update

contents

GIIGNL's Technical Study Group introduces a series of Information Papers that provide factual information about Liquefied Natural Gas (LNG). This paper describes the operational safeguards which the industry implements as standard practices to detect, control and minimize potential effects from a release of LNG.

SAFETY SAFEGUARDS IN MANY LAYERS

The safety of LNG worldwide is the result of high industry standards, effective regulations, and a fervent industry commitment to rigorous risk management. Regardless of the type of LNG facility, there are multiple layers of protection implemented to minimise the likelihood of an LNG release. **Information Papers No. 4 and 5** describe ways in which the industry maintains operational integrity through regulations, codes, standards and best practices, and how the LNG is contained in various types of storage tanks. This paper describes industry safeguard systems designed to immediately detect, control and mitigate the consequences if a release of LNG were to occur in the import terminal.

There are two types of safety features in an LNG facility: management systems and equipment/technology systems. Management systems include studies during the design process which first identify hazards and then review the design to ensure that these hazards can be controlled or mitigated. During the operational phases, procedures are written to ensure that safe working practices are encouraged, inspections and maintenance are conducted in an appropriate and timely manner and that the impact on the public and employees of any unexpected circumstance is minimised.

With regard to safety equipment and technology, LNG facilities have multiple levels of hazard detection, mitigation and intervention systems. There are two types of intervention systems: those based on passive technology, which require no interaction, and active systems, where action is either automatic or an operator is prompted to take action.

PREVENTION

LNG facilities and LNG carriers are viewed in the industry as the "top of the line". This view is justly predicated on their high quality, robust safety systems and overall attention to detail in design, solid construction and stringent operational practices. All of these factors collectively serve to prevent accidents, incidents and product releases of any kind. The excellent safety record of the industry is substantive evidence of this commitment. There was a (single) major tank failure incident, which occurred in Cleveland, Ohio, US in 1944 at the beginning of the LNG industry, resulting in a fire and a number of fatalities. This incident is discussed in detail in **Information Paper 9 (Q&A's).** At the time of the Cleveland incident, the safe storage practices required for cryogenic liquids were not fully understood. Since then, the LNG industry has implemented safety improvements to prevent situations which could lead to or cause such incidents. Examples of standard practices which are now established around the world to prevent leaks and their escalation include the following:

- Compliance with known and proven codes and standards for designing and siting new facilities;
- Siting new facilities a safe distance from adjacent populations based on risk assessments;
- Construction of special materials and inclusion of systems designed to safely insulate and store LNG at temperatures of -162°C (-259 °F);
- Various codes and standards for maintenance and inspection of equipment in LNG service;
- Overpressure protection (pressure controllers and relief valves);
- Leakage detection and spill control through temperature probes;
- Ignition source control;
- Fire zoning;
- Emergency depressurising;
- Passive fire protection, e.g., fireproofing, fire resistant barriers and coatings; and
- Active fire protection.

Additional standard devices and practices specifically for tanks include:

- Cool-down temperature sensors on the tank wall and base;
- Leak detection equipment, e.g., temperature sensors, and low temperature alarms, located in the annular space;
- LNG tank gauging systems to provide remote readings, with high/low level alarms which trigger emergency shut down systems; and
- Combined temperature and density sensors to detect rollover potential.

In Europe, the Seveso III Directive requires a complete Safety Management System for the control of major-accident hazards. This System must include a safety study with a risk analysis and relevant measures for the mitigation of consequences. The final risk level must be acceptable to the authorities.

In the US, the regulations generally require that these worst-case spill hazards are contained within the perimeter of the owner's property such that risk to the public is near zero.

In Japan, JGA (Japan Gas Association) published safety guidelines for aboveground and underground LNG tanks. It contains design layout (security distance etc.), disaster prevention facilities (safety valve, security electricity, etc.), monitoring (alarming) system, communication system, shutdown system and maintenance philosophy for these safety facilities. JGA also published safety guidelines for gas manufacturing facilities containing same contents as mentioned above. These guidelines were updated in 2017 based on the experience of 'The 2011 off the Pacific coast of Tohoku Earthquake' adding countermeasures against Tsunami.

Locating LNG facilities and vessels a safe distance away from adjacent industry, communities and other public areas provides the assurance of protecting citizens from potential hazards in case a serious incident occurs. In the current environment, where there is a threat of terrorism, the public is understandably concerned that bulk storage of a flammable energy source represents a risk. Separation of LNG from the public can take the form of exclusion zones for facility-siting or safety zones around LNG ships while underway. The separation distances used in codes, standards, and regulations are based on risk assessments and scientific analyses.

In addition to industry best practices and governmental requirements, financial institutions specify guidelines to assure that LNG facilities are safe and worthy of financing and insurance. The World Bank Group states in its guidelines that the layout of an LNG facility (and the separation distance between the facility and the public and/or neighbouring facilities outside the LNG plant boundary) should be based on an assessment of risk from LNG fire (entitled a "thermal radiation profile prediction"), vapour cloud ("flammable vapour cloud dispersion characteristic prediction"), or other major hazards. The results of such risk assessments define the recommended separation distance for a proposed facility. Generally in Europe, depending upon the design and storage capacity of the subject facility, risk assessments recommend a separation distance from residential, recreation areas, or other public built-up areas. In simple terms, separation distances ensure that the surrounding public is protected from the consequences of any credible LNG release at a terminal.

The industry standards and regulations described in **Information Paper No. 4** reduce the likelihood of a release. If a release were to occur, the consequence is minimised through the use of secondary containment and active safety mitigation systems described in this paper.

Figure 1 illustrates multiple layers of protective measures, for instance, to prevent the escalation of an LNG leak into a pool fire and to minimize the consequences of such an incident. The occurrence of a hazardous event, in this case, a pool fire, would require the simultaneous and very unlikely failure of several, independent layers of protection.

The layers of protection implemented at terminals include risk mitigation measures such as the following:

- **Spacing and design of pipes, equipment and storage tanks:** they must be made of specific materials in order to resist cryogenic temperatures and avoid LNG leaks. LNG tanks are equipped with integral impoundment.
- **Detectors:** Facilities are constructed with a variety of leak detection devices, including cameras, temperature sensors and various kinds of very specific detectors (for discovering fire, flame, gas, smoke or tank overfill). This detection equipment communicates to the control centre and can automatically trigger emergency shut-down systems (some examples are shown in Figure 2).

- **Emergency shut-down (ESD) valves**: In case of fault detection, ESD valves are automatically closed to prevent the further loss of LNG.
- **Impounding areas**: In the event of an LNG leak, the spill is contained in these areas to control its spread, vaporisation rate and, if a pool fire occurs, to minimise the consequence outside the terminal.
- **Fire control systems**: LNG fires can be mitigated with fire-fighting systems available throughout the terminal.
- **Vapour reduction systems**: if an LNG pool has formed, foam generators can be used to reduce the rate of vapour formation and movement.
- **Trained operators**: operators are always present in the terminal to control operations and ensure rapid response to any emergency condition, including making emergency notifications to agencies and responders, as well as an emergency broadcast to the community.

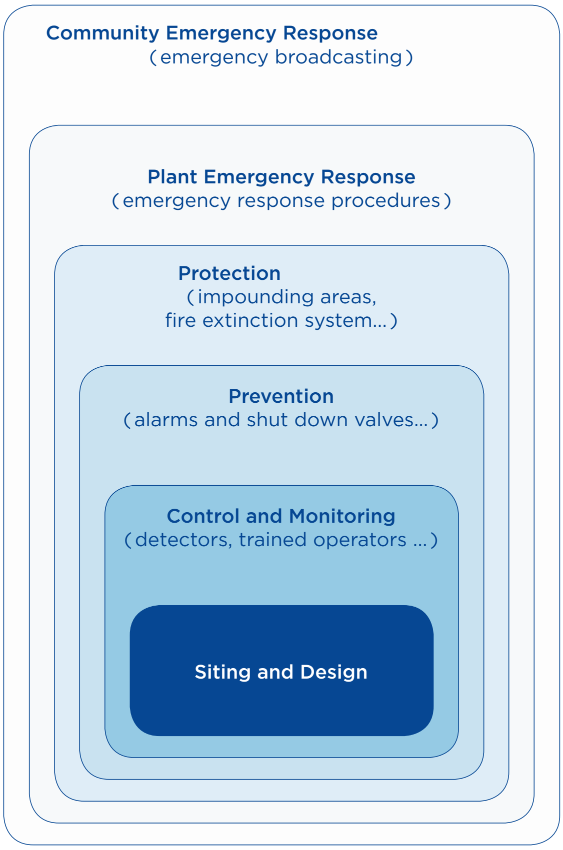


Figure 1. Layers of protective measures to prevent escalation of an LNG leak into a pool fire *(Source: BV 2009)*

Operations and maintenance personnel in LNG facilities are required to be trained, both initially and periodically thereafter, in:

- The hazards of LNG;
- The hazards of operation and maintenance activities;
- How to recognise breaches of security and execute security procedures;
- Understanding the potential causes, types, sizes and predictable consequences of fires and knowing and following fire prevention procedures;
- How to perform their assigned functions during both normal operations and emergencies; and
- How to provide first aid.

Verification of compliance with these requirements is performed by each national dedicated Authority.

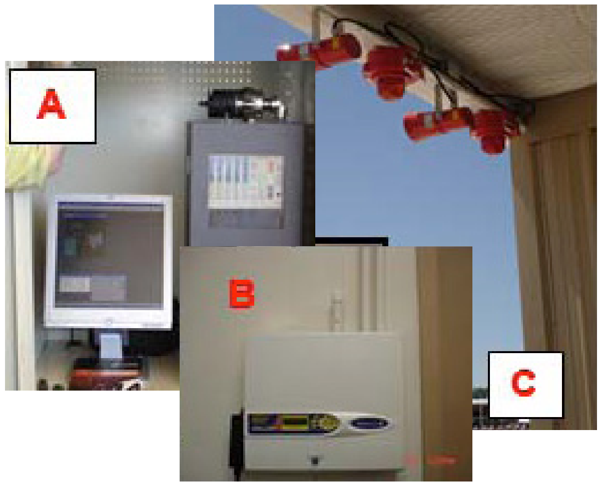


Figure 2. Detection and warning devices for LNG terminals: A) flame detection monitoring in a control room, B) aspirating smoke detector, and C) audible alarms
(Photos provided by A.H. Walker)

DETECTION

Several systems incorporate monitoring and control devices to detect deviation from acceptable parameters, thereby enabling corrective action to prevent unsafe conditions. Standards and codes require that combustible gas detectors and low temperature detectors are located at places where an LNG release might occur and where LNG or low temperature vapour might accumulate. In Europe, the code is: EN 1473. In the US, they are: NFPA 59A 49 CFR Part 193.2507, Subpart I and 49 CFR Part 127.201-3. These detectors are continuously monitored. They also have alarms set just above the detection levels and automatic shutdowns at hazard levels.

For facilities on land, monitoring systems are required by EN 1473 in Europe, 49 CFR Part 193 and NFPA 59A in the US and JGA-10 in Japan. Onboard ship, monitoring systems are required by the International Gas Carrier Code, the classification society's requirements and the USCG requirements of 46 CFR 153-154 and 33 CFR Parts 127, 160-169.

In addition to the code-required instrumentation specifically for leak detection, there is abundant normal process instrumentation which will alert an operator to an abnormal condition which may or may not be caused by leakage. Many areas are either covered by remote TV cameras or are visible to a plant operator or to a crew member from a ship's control room. An LNG release of any size is easily recognized visually, because of the condensation of water vapour from the atmosphere within any resulting cloud.

All LNG facilities have equipment to detect an LNG release and to initiate immediate notification so as to control the leak or spill. Vapour and liquid detection equipment is used to detect problems, set off alarms and monitor flammable vapours. Remote monitoring screens, e.g., in a control room, provide a means to instantaneously see the situation and manage the overall facility. Closed-circuit TV is used to monitor operational areas in the terminal and serve as a secondary visual system for the gas, flame, and fire detectors. Detection and initial response equipment includes:

- Cryogenic liquid detection.
- Leak detectors designed to detect low temperatures,
- Gas or vapour detection,
- Smoke detectors,
- Flame detectors,
- Safety alarms,
- Emergency shut down valves to limit the quantity of LNG released, and
- Secondary containment designed to mitigate the consequences of release.

Continuous improvements are made in detection systems.

CONTROL AND MITIGATION

A hazardous event (e.g., a pool fire) could only occur due to simultaneous failure of several independent layers of protection.

If a liquid spill is detected, emergency shut-down valves may be automatically activated depending upon the situation, e.g., size of the spill and the location. They can also be activated manually by push buttons at the jetty, control room, around the terminal and on the LNG ship (when it is at the jetty). The emergency shut-down system stops all pumps and closes off all piping so that the LNG stays either in the storage tanks or on the ship if there is a ship offloading. In many terminals, emergency-release couplings on the unloading arms or flexibles, used to transfer LNG between the ship and the shore, are quick break-away lines that shut the unloading system down and allow the ship to move away from the jetty.

If a leak is detected, actions are taken to:

- Prevent fire by securing the leak and the area, eliminating ignition sources, and monitoring vapours until no flammable vapours remain;
- Warn and shelter facility workers and notify authorities as required or appropriate;
- Control vapour dispersion with foam and/or water curtains;
- Use water spray to increase the vaporisation rate of the LNG (rapidly warm it), which will facilitate a more rapid mixing and dilution of LNG vapours to outside flammable limits, and help them warm more quickly to the temperature at which they will become buoyant and rise away from ignition sources and people on the ground (see Information Paper No. 1); and
- Control and manage/mitigate incidents if vapours are ignited, using dry chemical powder or foam, and applying water to plant equipment (not the LNG fire) to cool it down.

High-expansion foam and water-spray curtains help control LNG vapours in a proactive manner. The application of foam to LNG spills on land, or water spills that are contained, e.g., in a storm drain or small pond, is an effective hazard control technique. Applying and maintaining a "blanket cover" of high-expansion foam can help to minimise ignition risk and/or to manage vaporisation rates and vapour dispersion, when either of these actions is appropriate for the specific situation. The use of water curtain sprays to form water barriers between LNG vapours and potential ignition sources can also be an effective risk mitigation technique for a liquid spill. Dry chemicals can be applied to extinguish flames if the vapours in a contained area ignite. High-expansion foam has proven effective in reducing flame height and radiant heat.

In the event of a leak or spill, responders wear personal protective equipment (PPE) while undertaking control and mitigation actions. Common PPE equipment in industrial operations includes safety goggles, steel-toed boots, gloves, and hard hats. In an LNG facility, PPE for protection from cold liquids and vapours, e.g., face shields suitable for contact with cryogenic materials, are also standard. During an LNG incident, additional personal protective equipment might include a breathing apparatus (depending upon the magnitude of any gas release), since LNG vapours can displace oxygen and lead to asphyxiation, along with fire protection gear such as:

- Full protective clothing (coat and trousers),
- Anti-flash hood,
- Fire helmet with visor,
- Fire gloves, and
- Fire boots.

INSPECTIONS

Government agencies routinely inspect LNG facilities and ships to verify that safety measures have been correctly applied and maintained. Inspections vary among countries, or regions. For example:

- Europe The Safety Management System, required by the European Directive Seveso III and implemented by the operator, includes internal control loops for every safety activity. In addition, verification of compliance is made by oversight agencies and inspections are performed by local authorities.

- US Safety activities and inspections are under the jurisdiction of several agencies: the US Coast Guard, the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the US Department of Transportation, and the Federal Energy Regulatory Commission (FERC). All of these agencies inspect terminal operations after start-up. Each agency will verify safety compliance with their respective jurisdictions through inspections. The inspection rate is chosen by the responsible agency and will vary by facility.
- Asia In Japan, the Ministry of International, Trade and Industry (MITI) prescribes inspection frequencies.

EMERGENCY RESPONSE PLANS

Being prepared for any emergency is an essential activity for LNG terminals and ships. A set of preparedness activities conducted before an incident helps assure that any incidents that do occur are well managed and mitigated. To be most effective, preparedness activities are conducted in a sequence, where the results of one activity leads into another, with the end result being that overall preparedness is constantly improving. This is referred to as the Preparedness Cycle (**Figure 3**). Preparedness is achieved and maintained through a continuous cycle of planning, organising, training, equipping, exercising, evaluating, and taking corrective action. Ongoing preparedness efforts among all those involved in emergency management and incident response activities ensure coordination during times of crisis.

A good emergency response plan helps assure that responders have optimal control over an incident. Beginning to plan response actions at the time of an incident is an extra but avoidable challenge. For this reason, LNG facilities prepare and maintain emergency response plans which identify potential credible incident scenarios and then develop specific actions to mitigate the consequences of such incidents.

The regulations of countries, including the US and Europe, and companies, specify the content of these plans. For example, emergency response plans for import terminals, which in the US are required by FERC and must be approved before the terminal even begins operations, must include scalable procedures for responding to:

- Emergencies within the LNG terminal;
- Emergencies that could affect the public near an LNG terminal;
- Emergencies that could affect the public along an LNG vessel transit route;
- Methods for notifying agencies and the public; and
- Training and exercises using the plan.

It is important to involve all response stakeholders (including adjacent facilities) in the planning process to develop the plan. The facility emergency response plan is prepared in consultation with appropriate local and national governmental agency representatives, including first responder representatives. The valuable benefit of a plan is the planning process of working through incident management issues.

Figure 3. Preparedness cycle *(Source: US FEMA)*

Another key component of emergency planning is the training of all emergency responders, which incorporates coordination, communication, drills and exercises. Hazards and mitigation scenarios are identified and used to develop responses and role assignments. Simulated emergencies, both table-top and full-scale, are used to validate the effectiveness and efficiency of both individual responders and responding organisations. Field exercises provide an opportunity to practice hands-on skills and cultivate expertise.

Participating in such training and exercises helps assure that the emergency response plan will be well understood by the organisations with responsibilities during an incident and that they are ready to respond effectively in the unlikely event of an emergency.

KEY POINTS AND CONCLUSIONS

In closing, the key points of this information paper are:

1. Industry safeguard systems are designed to immediately detect, control and mitigate the consequences of any LNG release in an import terminal.

2. There are two types of safety features in an LNG facility: equipment/technology systems and management systems. The former include multiple levels of hazard detection, mitigation and intervention systems. The subject intervention systems may be active systems, requiring an operator to act or being automatically started, or passive systems, requiring no interaction.

   Management systems, include, among other things, studies during the design process which first identify the hazards and then review the design to incorporate steps which eliminate or control/mitigate the hazards. They also include, for example, the drafting, refinement and implementation/dissemination of sound operating procedures and safe working practices.

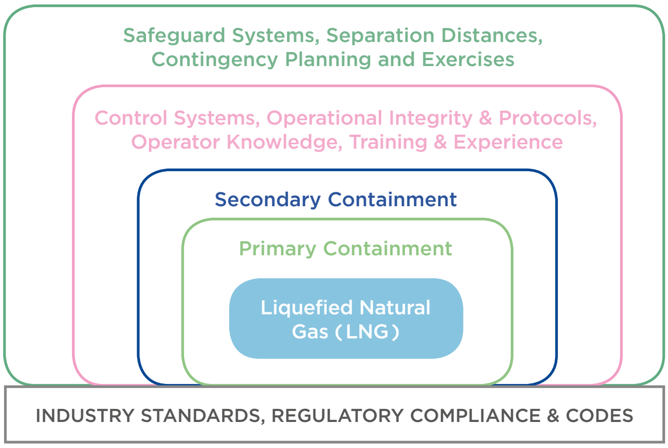
3. Safety design of facilities, systems, and equipment in the LNG industry are generally viewed as "top of the line", largely due to their high quality, robustness and implicit attention to detail.

4. The tragic accident in Cleveland, Ohio, US over 60 years ago, when LNG first became commercially viable, resulted in a fire and a number of worker and public fatalities. As a result of the exhaustive subsequent investigation, a comprehensive number of safety precautions have been implemented and are in effect throughout the industry.

5. Typical layers of protection implemented in modern LNG terminals are graphically illustrated in **Figure 1.** These layers begin, in a sense, with the Siting and Design of the terminal. The next layer reflects the Control and Monitoring features (including, for example, detectors and trained operators). Prevention components include alarms, shut-down valves, etc. Protection is provided by elements such as impounding areas and fire extinction systems. Company management of the incident is provided by implementing the Plant Emergency Response procedures. In addition, Community Emergency Response begins with notification about the leak or other incident, which activates governmental oversight, mobilizes additional response resources to reinforce the facility's response, and thereby protects the public and adjacent properties.

The goal of this series of papers has been to identify and describe the many components which comprise LNG safety along with providing a global sense of LNG risk management.

Multiple Safety Layers Manage LNG Risk



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LNG INFORMATION PAPER

#5

2019 Update

Managing LNG Risks
Containment

contents

GIIGNL's Technical Study Group introduces a series of Information Papers that provide factual information about Liquefied Natural Gas (LNG). This paper describes the tanks used to store LNG, which should be viewed as the primary means for safely containing LNG and preventing the exposure of LNG's extremely cold temperatures and flammable vapours to facility workers or the public. Secondary containment, i.e. ways in which the tank contents will be captured on site in the unlikely event of a leak or spill, is also discussed.

INTRODUCTION

A primary safety requirement for the industry is to contain LNG. LNG is stored in large tanks at liquefaction facilities and import terminals. At an import terminal, LNG is stored until it is either reloaded on trucks/LNG ships or turned back into natural gas through regasification and then sent out to consumers in pipelines. A typical LNG import terminal has 2 to 4 LNG storage tanks (although a small number have only 1 or over 10 tanks).

Storage tanks are a critical component of LNG terminals. The minimum construction time is 32 to 40 months. Storage tanks require substantial capital expenditures.

LNG can also be stored at a floating terminal (Floating Liquefaction Unit, Floating Storage Unit (FSU), Floating Regas Unit (FRU) or Floating Storage and Regas Unit (FSRU), Floating Units (ships or barges) which generally require lower capital expenditures than onshore terminals but may entail higher operating costs. Floating terminals must comply with all relevant regulatory requirements, including those of the International Maritime Organisation (IMO), International Gas Carriers (IGC) and the US Coast Guard (USGC). For additional information on floating units, please refer to **Information paper N°3.** This paper focuses primarily on the onshore terminals.

LNG tanks have more than one means of containment. The first layer of containment is provided by the tank which holds the LNG. All LNG storage tanks are constructed with thermal insulation to prevent heat transfer, reduce evapo-ration, and protect the structure from cryogenic tempera-tures which could damage the structural integrity of the tank. Secondary containment is provided either by the use of dikes, berms and impoundment dams around storage tanks, or by building a second tank around the primary storage tank to contain the LNG in the unlikely event of a failure in the primary tank.

The decision to use a particular design is influenced by available space and local requirements. The vast majority of LNG storage tanks are above-ground. Some countries have constructed partly or fully below ground. For LNG storage different concepts are applied depending on individual process or local requirements.

While flat-bottom tanks are operated at pressures below 0.5 barg, in spherical and bullet tanks the product is stored at 2.0-3.0 barg to which the LNG supply chain systems (LNG trucks, ships, etc.) are compatible.

Atmospheric storage is well established and compre-hensively regulated by codes, applicable for large tanks. Spherical and bullet tanks are more applicable for small terminals or satellite stations.

STORAGE TANKS

The tanks in which LNG is stored are the means for primary containment. Safe and secure containment is in part a function of the codes and standards which contribute to the operational integrity layer of protection (described in **Information Paper No. 6**); these codes and standards define suitable engineering designs and specify appropriate materials for constructing storage tanks and other equipment at LNG facilities. Several types of tanks are used to store LNG in the world today. In some places a reinforced concrete tank surrounds the inner tank. Types of onshore LNG storage tanks include:

- Single containment tank,
- Double containment tank,
- Full containment tank,
- Membrane tank, and
- In-ground tank.

Single Containment Tank

A single containment tank is composed of an inner cylindrical container made of 9% nickel or stainless steel which is self-supporting (**Figures 1 & 2**; next page). This inner tank is surrounded by an outer tank made of carbon steel which holds an insulation material (usually an expanded mineral material called perlite) in the annular space. The carbon steel outer tank is not capable of containing cryogenic materials; thus the inner tank provides the only containment for the cryogenic liquid. However, single containment tanks are always surrounded by a dyke (bund or containment basin) external to the tank that provides a secondary containment volume of at least 100% of that of the inner tank in the event of a complete failure of the inner tank. This type has an excellent history of reliability but the need for a containment dyke does require a relatively large area of land.

Double Containment Tank

The double containment tank is similar to a single containment tank, but instead of a containment dyke there is an outer wall usually made of post-stressed concrete (**Figure 3**; page 4). Therefore if the inner tank fails, the secondary container is capable of containing all of the cryogenic liquid.

The outer concrete wall increases the cost of the tank, but less space is required because there is no need for a containment dyke. Should the inner tank fail, the liquid will be contained and vapours will escape through the annular gap, which is the space between the two tanks or the tanks and the concrete wall.

Full Containment Tank

A full containment tank is a double containment tank in which the annular gap between the outer and inner tanks is sealed (**Figure 4**; page 4). The majority of large LNG storage tanks built in the last 20 years worldwide have been designed as full containment tanks.

In this tank, the secondary container is liquid- and vapour-tight in normal operations. In case of leakage of the primary barrier, the secondary container remains LNG- tight. The secondary container wall of a large tank is generally made of pre-stressed concrete and the roof is usually reinforced concrete, although under EN 1473 metal roofs may be allowed.

The membrane type of storage tank is a full containment post-stressed concrete tank with a layer of internal load-bearing insulation covered by a thin stainless-steel corrugated membrane (**Figure 5**; page 4). In this design, the concrete tank supports the hydrostatic load (weight of the liquid) which is transferred through the membrane and insulation (in other words, the membrane is not

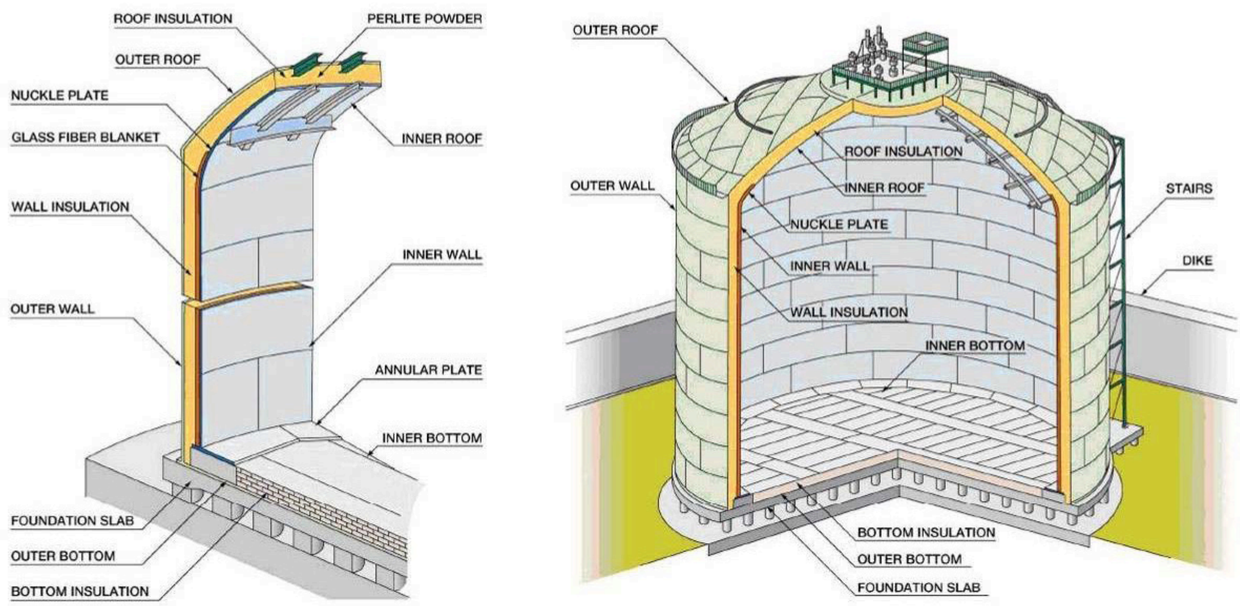


Figure 1. Single containment tank *(Source: Kawasaki Heavy Industries, Ltd.)*

self-supporting). The membrane is able to shrink and expand with changing temperatures. These tanks were constructed primarily in France, Korea and Japan in the 1970s and 1980s.

An LNG bullet or spherical tank is defined as full integrity when the inner and the outer container of the vessel are constructed from cryogenic steel being able to hold the LNG. In case of inner tank leakage the cryogenic liquid is contained in the outer tank and the structural integrity of the complete bullet is maintained. An example for a full integrity LNG bullet is given in **Figure 6.**

In-ground Tanks

In-ground LNG tanks are obviously less visible in their surroundings (**Figure 7**; page 5). They are mainly used in Japan and some other Asian countries. They were developed by Tokyo Gas Engineering (TGE) in the early 1970's based on earlier designs in the UK, the US and Algeria and subsequently used by other Japanese companies.

These tanks are more expensive and take longer to build than an above-ground tank – about 4 to 5 years compared to 3 years for a tank built above ground. The terminals with in-ground tanks are designed to harmonise with the surroundings and ensure safety at every stage of the lifecycle. These tanks do not need to be surrounded by a dyke or bund wall, so the separation distance from adjacent land is less than that of other types of tanks. This is especially important for countries such as Japan, Korea, and Taiwan.

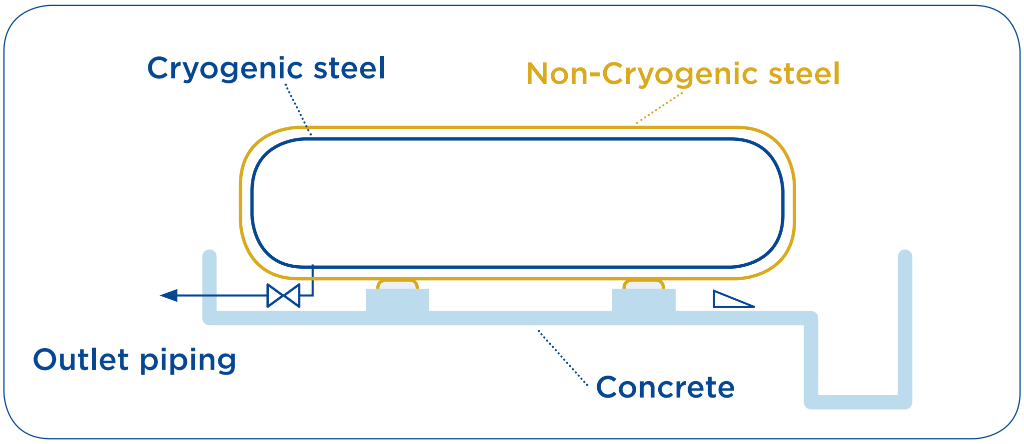


Figure 2 : Single integrity LNG bullet, surrounded by a dike.

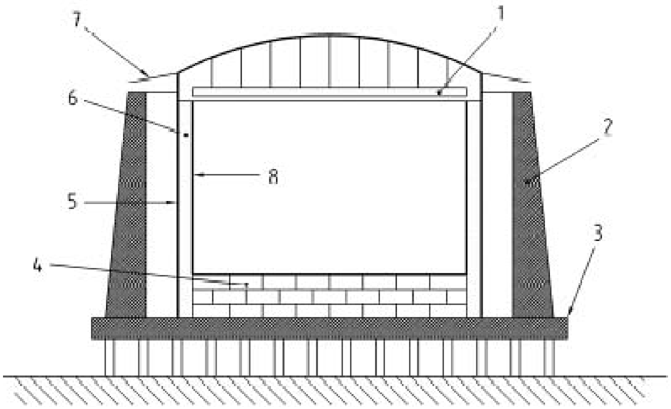


Figure 3 : Double containment tank *(Source: EN 1473)*

Key

1. suspended deck (insulated)
2. post-stressed concrete secondary container
3. elevated slab
4. base insulation
5. outer shell (not able to contain liquid)
6. loose- fill insulation
7. roof if required
8. primary container

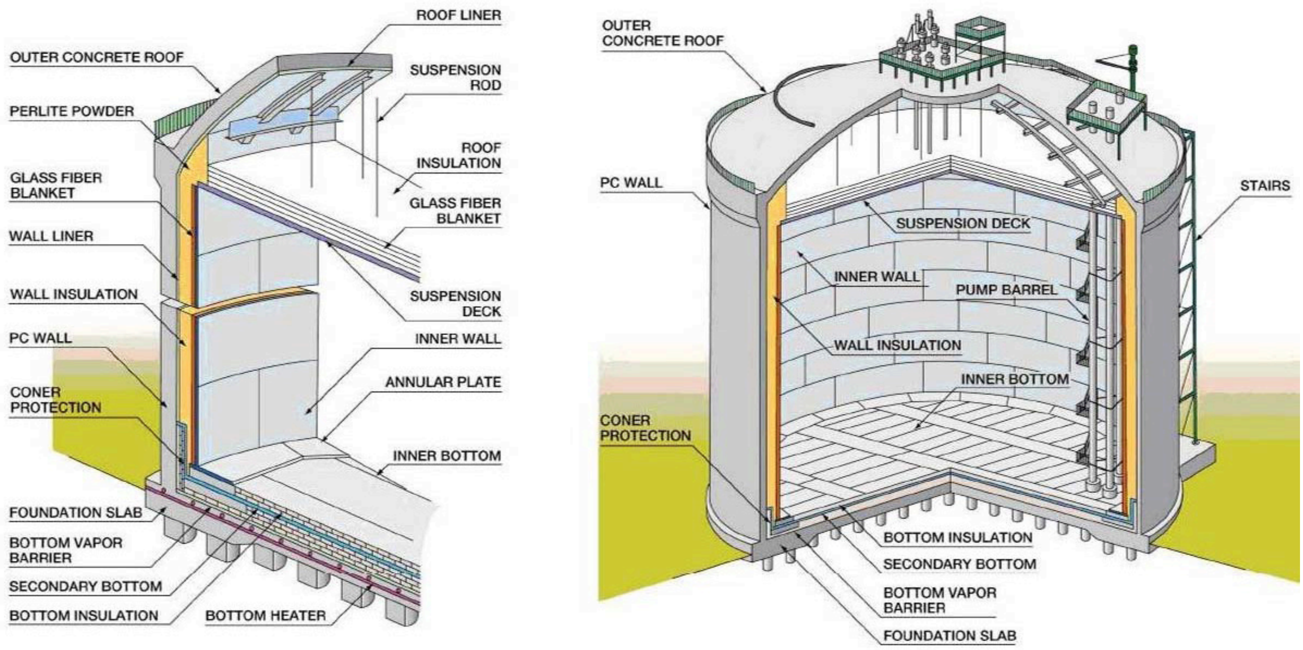
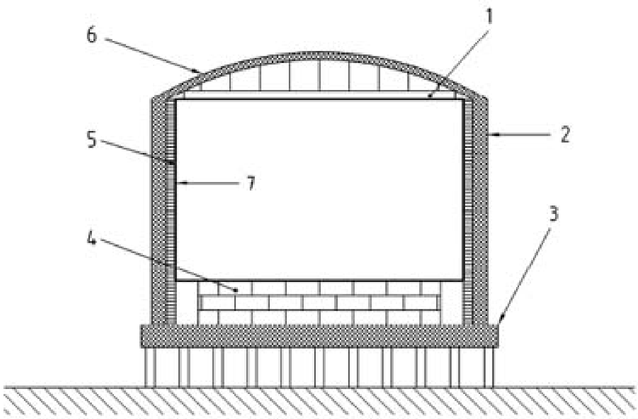


Figure 4. Full containment tank *(Source: Kawasaki Heavy Industries, Ltd.)*



Key

1. suspended deck (insulated)

2. post-stressed concrete secondary container

3. elevated concrete raft

4. base insulation

5. loose fill insulation

6. reinforced concrete roof

7. primary container membrane

Figure 5. Membrane tank *(Source: EN 1473)*

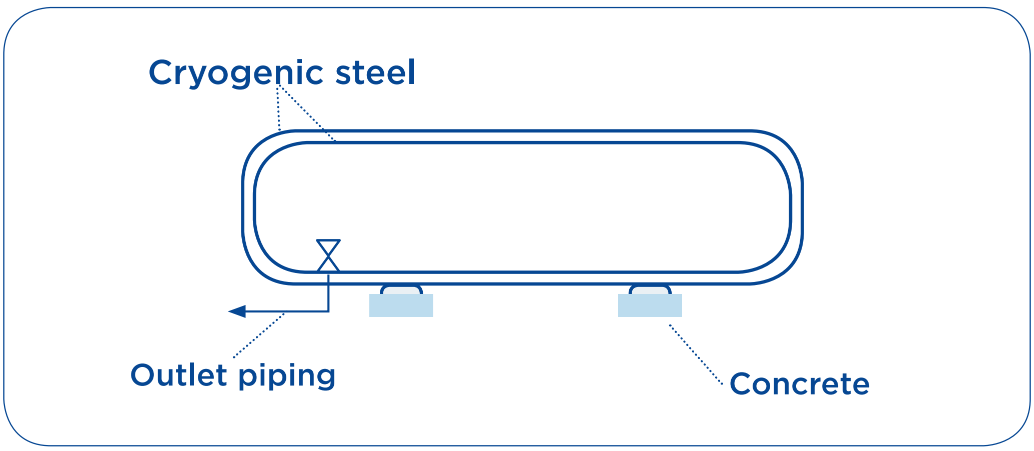


Figure 6 : Full integrity LNG bullet

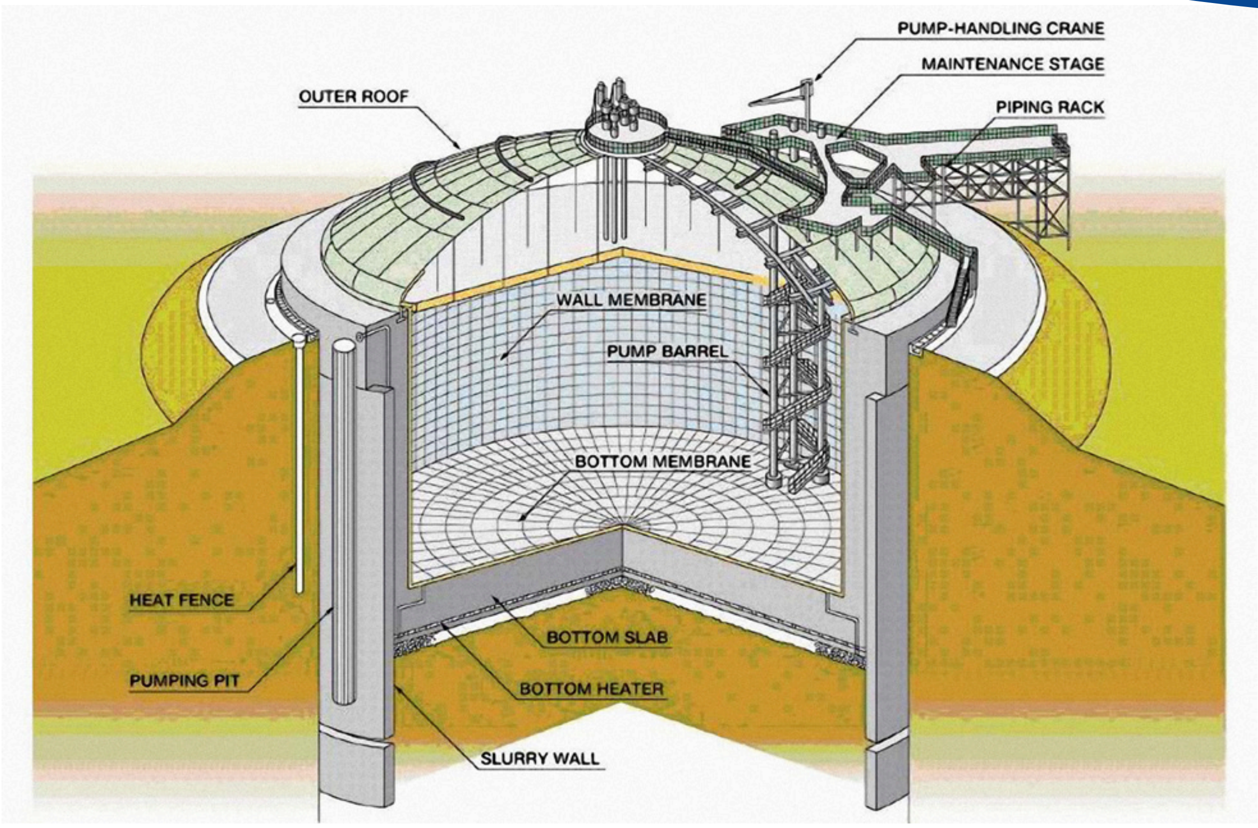


Figure 7 : In-ground storage tank *(Source: Kawasaki Heavy Industries, Ltd.)*

LEAK AND SPILL CAPTURE

In over 50 years, there have not been any incidents concerning LNG tanks which have had any impact beyond the terminal boundary.

LNG terminals are designed to detect any vapour leaks, as well as to detect and capture liquid leaks. LNG containment is a system which consists of the primary containment in the tank plus secondary containment, e.g., the impoundment around the tank to capture and keep in place any leakage of LNG. Storage tanks also incorporate the following measures to prevent leaks or detect leaks immediately at the source:

- Tank construction of special materials and equipment with systems designed to safely insulate and store LNG at temperatures of approximately -162°C (-259 °F);
- Cool down temperature sensors on the tank wall and base;
- Leak detection temperature sensors located in the annular space to signal a low temperature alarm;
- LNG tank gauging systems to provide remote readings and high/low level alarms;
- Level temperature density gauge to detect rollover potential;
- Pressure controllers and relief valves.
- Passive fire protection, e.g., fireproofing, fire resistant barriers and coatings; and
- Various codes and standards for maintenance and inspection of equipment in LNG service.

Many of these safety measures in tank design and construction were implemented to prevent a re-occurrence of the incident at a peak-shaving facility in Cleveland, Ohio, US in 1944, 20 years before LNG became a significant industry. Post-incident analysis clearly demonstrated that the size of the design of the capture basin was inadequate. Since then, codes and standards have been developed to require a second layer of protection around the primary containment (of single-containment tanks). Single-containment tanks now must be designed to prevent the spread of an LNG spill. Dykes, berms, and dam impoundments surround each single-containment storage tank to capture the LNG in case of a spill. The size of impoundment areas must be able to capture a volume which exceeds that of the storage tank. Dykes are designed to contain 100-110% of the tank volume and to be high enough so the trajectory of a leak at the upper liquid level in the tank can not overshoot the edge of the dike. Impoundment areas often have concrete or earthen liners and employ some method for extracting rain and deluge water.

In the unlikely event of a leak of any kind, all LNG facilities have many types of equipment to detect a release, and initiate immediate notification and control of the leak or spill. Standard detection and initial response equipment in various areas of an import terminal include:

- Cryogenic liquid detection;
- Gas or vapour detection;
- Smoke detectors;
- Flame detectors;
- Safety alarms;

- Emergency shutdown valves on piping to stop the flow of LNG and limit the quantity of LNG released; and
- Secondary containment designed to mitigate the consequence(s) of release.

Vapour and liquid detection equipment is used to detect, set off alarms and monitor flammable vapours. Most devices have remote monitoring screens, e.g., in a control room, and provide a safe and secure way to monitor the situation and manage the overall facility. Continuous improvements are made in detection systems and there are vendors who specialise in systems just for LNG.

LNG facilities develop and maintain emergency response plans for the unlikely event of any leak. These plans identify potential credible incident scenarios and then develop specific actions to control and mitigate the consequences of these incidents.

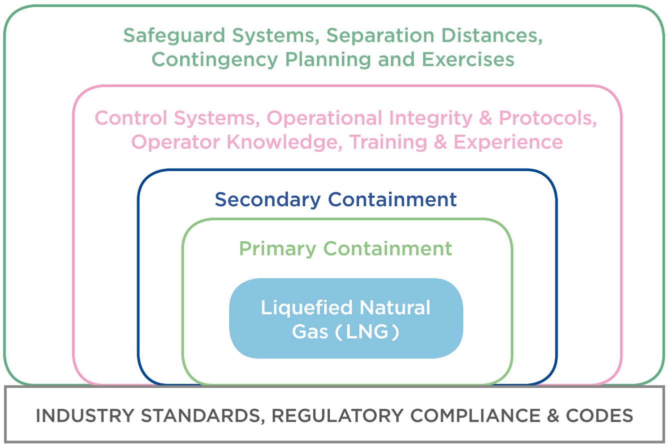
KEY POINTS AND CONCLUSIONS

In closing, the key points of this information paper are:

1. In an industry in which safety considerations are paramount, containment is the primary requirement for LNG safety. This is underscored by the degree to which related codes, equipment, regulations, procedures and systems permeate all of our efforts.
2. LNG facilities and terminals have more than one means of containment. Beyond the first layer (the specifically-designed and constructed tanks), various methodologies (including berms, dykes, impoundment dams and secondary tanks) are used to provide another layer of protection.
3. Various kinds of tanks are used around the world, including Single Containment Tanks, Double Containment Tanks, Full Containment Tanks, Membrane Tanks and In-ground Tanks.
4. Liquid and gas/vapour leak detection and response systems incorporate a wide array of relevant devices and technologies, including alarms, emergency plans and shutdown valves, fireproofing/fire-resistant barriers and coatings, flame detectors, gauging devices, pressure controllers, relief valves, smoke detectors and temperature sensors.
5. Most detection devices and response systems have remote monitoring screens, e.g., in a control room, to provide a safe and secure way to monitor the situation and manage the overall facility.

As reflected in the illustration below, the Multiple Safety Layers for LNG are all firmly based on a foundation of solid Industry Standards, Regulatory Compliance and Codes, many of which are developed by the foregoing associations and regulatory bodies. These "safety layers" include several key components of the industry's Risk Management framework. Included among them are Primary and Secondary Containment, Control Systems which promote Operational Integrity; Protocols, Operator Knowledge and Experience (which are reinforced by comprehensive and ongoing training). A protective umbrella of Safeguard Systems, Separation Distances, and Contingency Planning further enhances the safe management of LNG.

Multiple Safety Layers Manage LNG Risk



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Natural Gas and the Clean Energy Transition

By Alan F. Townsend

In the clean energy transition, the value of natural gas infrastructure is very important for operating the energy system. Gas-fired power plants contribute to optimized energy systems when they are designed to operate flexibly, responding to demand patterns and the variable supply of renewable energy. Smart electricity grids, renewable energy, battery storage technology, and gas-fired power plants in combination will generally be the lowest cost, low-carbon solution to the growing energy requirements of emerging markets. Private investors and financiers are responding to these opportunities, but the full potential will only be reached with improvements in policy, regulation, and procurement in destination markets.

The de-carbonizing power sector solution for most countries will be characterized by several factors, including:

- A smart, integrated, and expansive network;
- Increasing penetration of photovoltaic (PV) solar, wind, and other lower cost renewables;
- Battery storage serving the short duration requirements of the network and its need to balance variable renewables in real time;
- A mix of gas-fired power generation capacity that supports further penetration of renewable energy, provides long-duration balancing resources, and ensures supply is reliable even when renewable energy generation is low.

Technically, this mix is already available on a commercial basis and its components are becoming more efficient and cheaper over time—dramatically so in some cases. This evolution will provide time for discovery and development of revolutionary breakthroughs that are expected to bring an end to both expansive integrated networks and fossil fuel-fired generation, though it is far from clear when exactly this will happen.

Figure 1 highlights the importance of gas-fired generation and the logic of de-carbonization. In many countries, especially in Asia, new energy has been a mix of coal and variable renewables, with natural gas sometimes marginalized. Flexible and efficient, gas produces half the

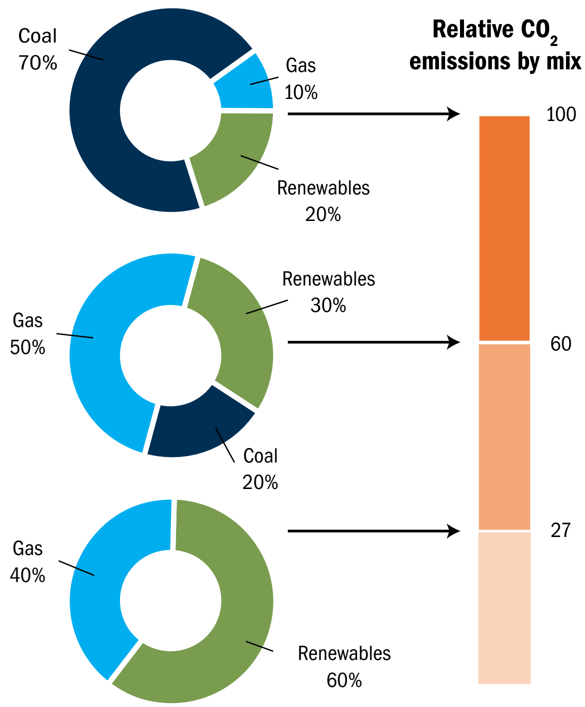

FIGURE 1 **Gas and the Clean Energy Transition**

Source: Author

About the Author

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emissions of coal per kilowatt hour (kWh), plus low or no sulfur oxides (SOx), nitrogen oxides (NOx), and particulate matter (though methane leakages need to be kept low). If its use can be expanded, so can renewables. The result is a 40 percent decrease in total emissions, even with some coal remaining in the system.

Gas can be economical even when the capacity is utilized flexibly, leaving room for more renewables. In the stylized example, when coal is eliminated from the system, emissions have been reduced by 73 percent. The final step toward zero greenhouse gas emissions, which is some years away, is when new storage technology, more efficient renewables, and ultra-smart grids obviate the need for gas at all.

The renewables/flexible gas solution is economically available now. That is, for most countries, the combination of flexible gas, variable renewables, smart networks, and storage will be least-cost for all capacity additions going forward. This is because, even without considering the cost of carbon emissions:

- PV solar, wind, and natural gas-fired turbines and engines have lower unit capital costs than coal-fired equipment, and there are natural incentives to combine solar, wind, and gas such that the required capital expenditure is least-cost compared to a coal-heavy mix.
- The all-in cost of PV solar and wind in many markets is below the marginal cost of natural gas, so total fuel costs can also be minimized.

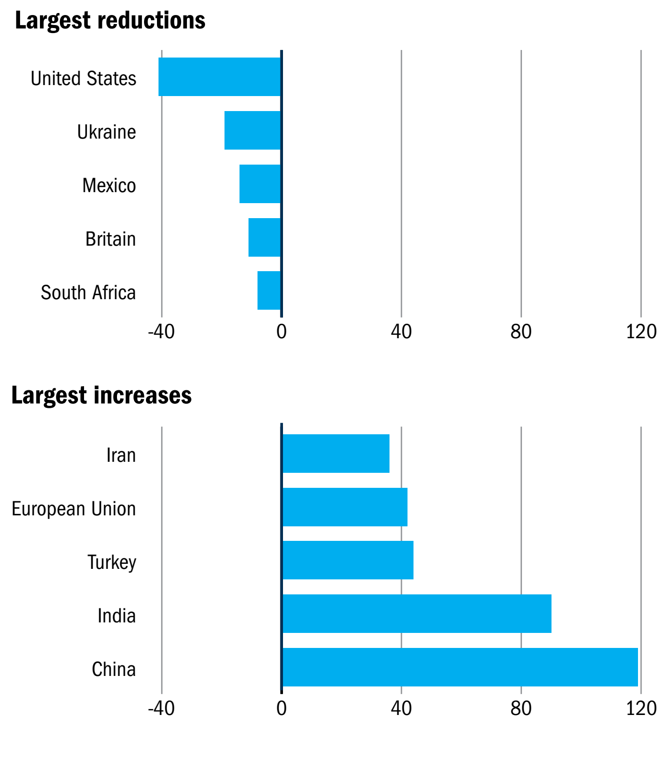

FIGURE 2 Change in CO2 emissions, 2016-17, million tons

Source: The Economist

Developed Markets Show the Way

Two of the biggest de-carbonizers on an absolute and relative basis are the United States and the United Kingdom (Figure 2). They have dramatically reduced their coal burn in the power generation sector while greatly increasing the penetration of renewables and natural gas. In the United Kingdom, a modest carbon tax has been enough to essentially eliminate coal from the country's power generation mix. The United States has no carbon tax, but the shale gas revolution has lowered the cost of natural gas to a level that leaves many coal-fired power plants unable to compete. In Europe and Korea, despite the occasional policy inconsistency, trends are in a similar direction—the combination of renewables and natural gas is pushing coal out of the mix.

Emerging markets have embraced natural gas as a power generation fuel but rarely as a strategic component of a clean energy mix. Grids are often weaker, battery storage has not entered most such markets, renewables policies vary widely and have sometimes been volatile, and many markets continue to develop new coal-fired power projects. Access to natural gas has frequently been a significant issue. Most emerging markets only had access to local gas reserves that came to market via pipelines. Until 2008, almost no emerging markets imported liquefied natural gas (LNG).

That changed with the advent of floating storage and regasification units (FSRUs), which are essentially floating LNG terminals. First in Brazil and soon thereafter in nations such as Argentina, United Arab Emirates, Indonesia, and Malaysia, FSRUs have opened new markets to LNG. In 2007 there were 17 importing countries. By end-2018 there were 40 importing countries and almost all new importers are emerging markets that have developed FSRU-based terminals.

IFC has analyzed FSRU examples globally to understand the motivations behind the individual projects, and the findings are striking (see Figure 3). Countries have turned to FSRUs primarily for three reasons: they needed LNG for a secure supply of natural gas, to provide back-up to hydroelectricity, or to make up for declining domestic gas reserves. In many cases, the consequence of not having access to LNG was a steep increase in the amount of oil burned in power generation. That changed when FSRUs came on-line.

There isn't a single emerging market LNG terminal in which the initial investment was primarily or even partly driven by the desire to complement variable renewables. And coal substitution is the primary motivating influence for only one project, Indonesia's Java-1 LNG-to-power, which is under construction (LNG-to-power refers to facilities that import and regasify LNG and then use it to generate power). These findings suggest that, although natural gas has a compelling role in a clean energy mix, LNG development in emerging economies has so far been driven by other concerns. As policy catches up to power

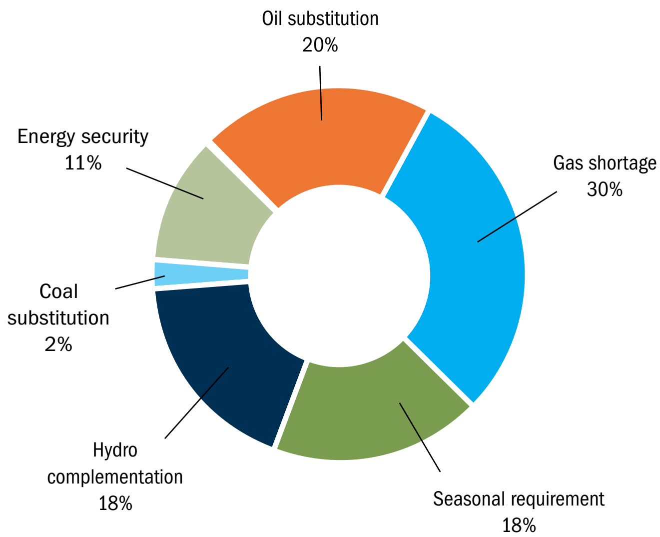

FIGURE 3 Primary motivation for floating storage and regasification units (FSRUs) – 44 projects total

Source: Author

sector decarbonization pressure, new opportunities will arise for gas-to-power.

Unbalanced Supply and Demand

Meanwhile, the LNG-to-power market is struggling. Even as the industry has responded to the potential for FSRUs by speculatively ordering many new, state-of-the-art vessels, there has been a noticeable slowdown in FSRU awards (Figure 4). While projects already under construction will add new importers to the roster of LNG consuming countries, no new emerging market terminals outside of China are scheduled to open beyond the early months of 2021.

About two dozen FSRUs are either available today or will be available as they come off contract between now and 2024. Rates for FSRUs are barely half what they were five years ago and several FSRUs are being used as LNG carriers.

While there are several reasons for the combination of demand contraction and supply expansion in the FSRU space, one factor looms especially large in explaining the steep fall in bankable projects: bad procurement practices. Of three dozen operating or under-construction projects in emerging markets, it can be argued that almost all have either been fully competitively bid or have had significant aspects subjected to competition by tender.

The flip side of this is that bilateral negotiation has produced almost no examples of FSRU projects being successfully concluded. Yet parallel, bilateral negotiation is an approach that is commonly seen in markets ranging from Ghana and Sri Lanka to Myanmar. And this approach has not seen any projects obtain financing and be brought into operation. This raises an important question: Why haven't the negotiated deals been financeable? Probably because they have lacked legitimacy across a wide range of stakeholders in politics, the media, the donor community, finance, and in the end-user/consumer community.

The dearth of financed deals may also result from governments having too many deals under negotiation (the logic seems to be that is the way to get the best deal). But when saying "yes" to one party is a de facto "no" to everyone else, sometimes no decision can be made. When the various ministries across the government apparatus are not aligned and not effectively coordinating across energy, transportation, industrial, and environmental policy streams, decision-making can also be paralyzed.

The market seems to be waking up to the peril of negotiated deals that can't be closed. Accordingly, the industry has become enthusiastic about participating in transparent and competitive tendering processes. Such processes are now ongoing in a diverse range of markets, including Benin, Lebanon, Cyprus, Sharjah (United Arab Emirates), Colombia, and Australia, and drawing significant interest from LNG suppliers, traders, and FSRU firms.

The next step is to recognize the capacity value of LNG-to-power infrastructure. Brazil's Porto de Sergipe, a 1,500 MW project, demonstrates this value. The project, now under construction, is economically supported by a fixed annual capacity fee sufficient to paying for a full range of fixed and non-fuel operating costs, including the lease on the FSRU. The plant is fully dispatchable. And when it runs, it will run because hydro reservoirs are low, and its energy will be very valuable indeed in a country with memories of drought-induced power rationing.

Porto de Sergipe will be the most efficient gas-fired plant in Latin America, with thermal efficiency of 62 percent. But

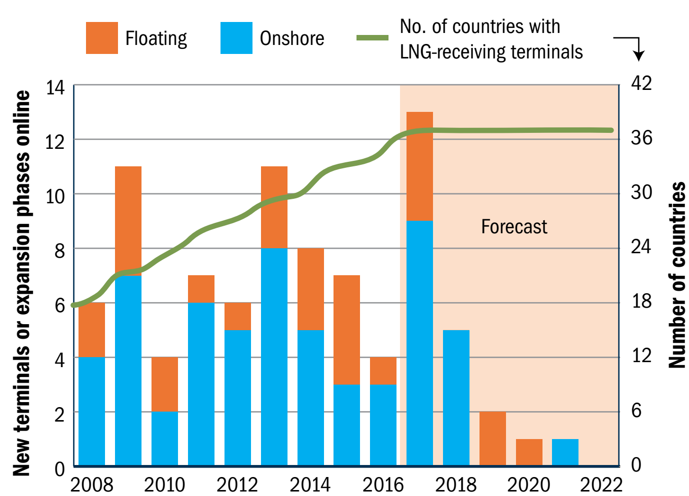

FIGURE 4 New terminals or expansion phases online 2008-22 for floating or onshore LNG storage

Source: International Gas Union (IGU)

when it rains it will not be needed, and LNG offtake can be reduced because the supply contract is highly flexible as well. Brazilian power customers will benefit: if the plant is forced to run because it must buy the gas, the annual cost of LNG will be about $600 million (at $10/million British thermal units (mmBtu)). Projects like Porto de Sergipe and Panama's AES Colon illustrate a critical fact of today's LNG-to-power space: that all players in the supply chain, other than the LNG supplier, can be indifferent to actual LNG consumption if contracts are structured appropriately.

This is a key insight because, consistent with the clean energy mix approach, there are two steps for gas in the transition. First, an increased market share for gas as it replaces dirtier fuels. And second, a decreasing share for gas as it is replaced by the combination of renewables and storage. This path for gas should be a conscious goal of energy policy makers.

Like the LNG-to power market, power generation equipment suppliers are also struggling. The big equipment manufacturers, especially General Electric and Siemens, are under pressure. Siemens estimates that suppliers of turbines of over 100 MW can manufacture 400 such units per year, but demand going forward will be no more than 110 units per year. Demand is soft for smaller units too, including both turbines and reciprocating engines.

LNG supply is nonetheless growing rapidly. The world is currently in the middle of the biggest LNG supply expansion in history, driven in recent years by rapid expansion of Australian and U.S. supply. By 2023, the International Energy Agency (IEA) projects that gas liquefaction capacity will exceed 500 billion cubic meters (bcm) of natural gas per annum, or about 400 million tons of LNG (Figure 5). And recent investment decisions—in Qatar, Canada, the United States, and other places—will add to supply after 2023.

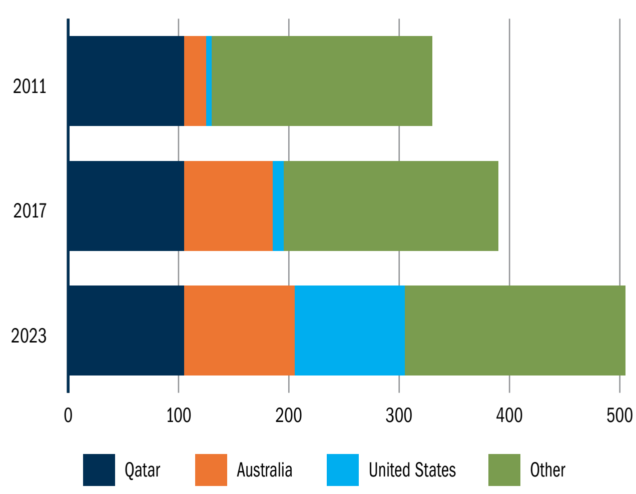

FIGURE 5 Global LNG supply growth 2011-23 (bcm)

Source: International Energy Agency (IEA)

Significantly, the basis for investment decisions has changed. Older projects have been underpinned by long-term offtake contracts with creditworthy buyers. Recent investment decisions have relied much less on contractual offtake and more on the equity strength of sponsors like Qatar Petroleum, Shell, Petronas, and Mitsubishi. Markets newly opening to LNG are always steps down the credit quality ladder.

Abundant LNG Reserves

This raises an important question: Why are producers committing billions to new LNG production despite the difficulties now seen in opening new emerging markets, and amid a global slowdown in gas turbine sales? There are several factors involved in the answer: Natural gas reserves are plentiful, but often far from potential markets; and LNG is often the preferred solution for remote gas reserves.

Those plentiful reserves mean that there is plenty of competition to get new projects to market, and firms that can take the equity approach (as opposed to being dependent on limited recourse project financing) have a distinct advantage. The LNG market is globalizing and commoditizing, reducing the risk of bringing on new supply if production costs can be contained. Finally, there is the reality that climate politics might turn some natural gas reserves into stranded assets at some point. This was certainly a factor behind Qatar's recent decision to lift the moratorium on further North Field development and commit to increasing LNG production capacity by nearly 50 percent, taking its output potential to 110 million tons per year, or over 140 billion cubic meters (bcm) per year.

A more flexible market helps. LNG companies know that, at worst, they will need to dump unsold LNG into the liquid markets of Europe, where annual utilization of LNG import capacity runs at 20 to 30 percent. Chinese demand is the wildcard: In 2017–18, China bought many of the available cargos, and European terminal utilization was low. In late 2018 and into 2019, China's appetite waned because of a warmer winter, and LNG suppliers had to put more into Europe.

The truism of the current market is that when China buys LNG, it turns a buyer's market into a seller's market. China is now the second largest buyer of LNG globally. It surpassed Korea this year and may overtake Japan as the largest LNG destination by 2020. China underscores a core environmental truth about natural gas: it is not just about the carbon. The purpose of Chinese LNG purchases has been to improve air quality in northern China, an effort that has been stunningly successful and is expected to continue for some time. China's LNG binge has contributed directly to increased confidence among LNG project sponsors, and that confidence translates, in part, to positive investment decisions for new capacity.

Conclusion

For emerging markets, LNG-to-power should be an essential part of a clean energy strategy. To make that happen, a handful of principles should be incorporated into the policy framework of individual countries:

- Countries need to embrace transparent and competitive tendering processes when awarding rights for energy infrastructure and energy supply.
- Natural gas has proven its carbon advantage relative to coal, and as China has shown, natural gas can have an immediate impact in reducing local pollution; these benefits should be incorporated in policy frameworks.
- Attention should be paid to replacing coal with a mix of flexible gas and renewables.
- In an increasingly flexible and commoditizing sector, LNG buyers and FSRU lessors should be clear about their requirements and should be careful about overcommitting on volume, tenor, or other factors; but contracts (with the right flexibility) remain critical pieces of the commercial supply chain. Buyers in today's gas market should be assertive but should also value stable relationships with reputable providers of LNG and infrastructure.

Box 1: Maximizing Finance for Development—Cascade Objective and Algorithm

Maximize financing for development by leveraging the private sector and optimizing the use of scarce public resources. WBG support will continue to promote good governance and ensure environmental and social sustainability.

When a project is presented, ask: "Is there a sustainable private sector solution that limits public debt and contingent liabilities?"

- If the answer is "Yes"—promote such private solutions.
- If the answer is "No"—ask whether it is because of:
  - Policy or regulatory gaps or weaknesses? If so, provide WBG support for policy and regulatory reforms.
  - Risks? If so, assess the risks and see whether WBG instruments can address them.

If you conclude that the project requires public funding, pursue that option.

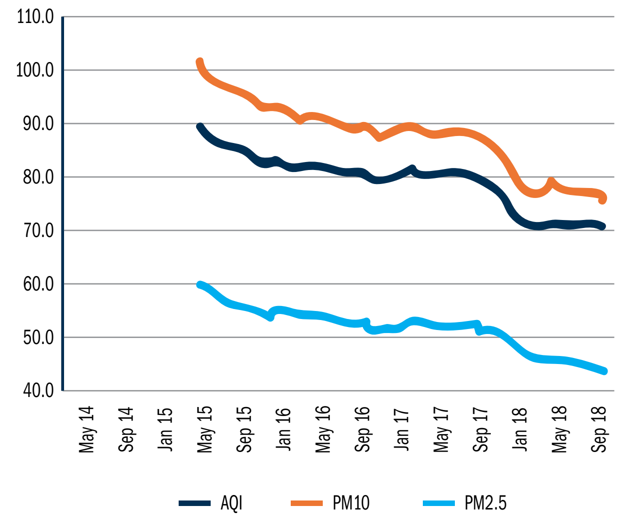

FIGURE 6 China: Particulate Matter and the Air Quality Index have been decreasing since 2015 (annualized basis)

Source: CNEMC, Citi Research

The private sector needs to be at the heart of efforts to mobilize finance for the clean energy transition. There is an opportunity to apply a maximizing finance for development (MFD) approach (Box 1) for gas that will address policy reform, market readiness, and enabling investments aligned to country climate targets.[1]

ACKNOWLEDGEMENTS

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Please see the following additional EM Compass Notes about energy opportunities in emerging markets:
Energy Storage–Business Solutions for Emerging Markets (Note 23); *Creating Markets in Turkey's Power Sector* (Note 33); *Using Blockchain to Enable Cleaner, Modern Energy Systems in Emerging Markets* (Note 61).

[1] See for example: World Bank Group. 2017. "Maximizing Finance for Development: Leveraging the Private Sector for Growth and Sustainable Development." Report prepared by the World Bank Group for the Development Committee, September 17, 2017, p. 6–7.

Box 2: About IFC and investing in LNG in emerging markets

IFC—a sister organization of the World Bank and member of the World Bank Group—is the largest global development institution focused on the private sector in emerging markets. We work with more than 2,000 businesses worldwide, using our capital, expertise, and influence to create markets and opportunities in the toughest areas of the world. In fiscal year 2018, we delivered more than $23 billion in long-term financing for developing countries, leveraging the power of the private sector to end extreme poverty and boost shared prosperity. For more information, visit www.ifc.org.

IFC has invested equity and debt in the first LNG terminals to come into operation in Pakistan and Bangladesh. IFC is senior lender ($150 million) to the AES/Motta Group Colon LNG-to-power project in Panama, and a senior lender ($200 million) to the Golar Power/ebrasil Porto de Sergipe Project. IFC has been the lead or co-lead debt arranger for LNG projects in Bangladesh, Panama, Brazil, and El Salvador.

IFC operates in partnership with the most significant companies in the LNG and power businesses. Our projects involve supply commitments from Qatar Petroleum, ExxonMobil, Shell, BP, and Total. Equipment and sometimes equity and EPC services have come from General Electric, Siemens, and Wartsila. Three of the four largest FSRU owners, Excelerate, Golar, and BW, provide vessels to IFC-financed projects. The largest commodity firms trade LNG through IFC-financed infrastructure, including IFC client Vitol. Leading financial institutions such as FMO, JICA, and Goldman Sachs work with IFC to support lending and project bonds.

Additional Selected EM Compass Notes Previously Published by IFC Thought Leadership

Note 64: Institutional Investing: A New Investor Forum and Growing Interest in Sustainable Emerging Markets Investments — February 2019

Note 63: Blockchain and Associated Legal Issues for Emerging Markets — January 2019

Note 62: Service Performance Guarantees for Public Utilities and Beyond—An Innovation with Potential to Attract Investors to Emerging Markets — January 2019

Note 61: Using Blockchain to Enable Cleaner, Modern Energy Systems in Emerging Markets — November 2018

Note 60: Blended Concessional Finance: Scaling Up Private Investment in Lower-Income Countries — November 2018

Note 59: How a Know-Your-Customer Utility Could Increase Access to Financial Services in Emerging Markets — October 2018

Note 58: Competition Works: Driving Microfinance Institutions to Reach Lower-Income People and the Unbanked in Peru — October 2018

Note 57: Blockchain Governance and Regulation as an Enabler for Market Creation in Emerging Markets — September 2018

Note 56: A Practical Tool to Create Economic Opportunity for Low-Income Communities — July 2018

Note 55: Peru's Works for Taxes Scheme: An Innovative Solution to Accelerate Private Provision of Infrastructure Investment — June 2018

Note 54: Modelo Peru: A Mobile Money Platform Offering Interoperability Towards Financial Inclusion — May 2018

Note 53: Crowding-In Capital Attracts Institutional Investors to Emerging Market Infrastructure Through Co-Lending Platforms — April 2018

Note 52: Crowding-In Capital: How Insurance Companies Can Expand Access to Finance — April 2018

Note 51: Blended Finance—A Stepping Stone to Creating Markets — April 2018

Note 48: Increased Regulation and De-risking are Impeding Cross-Border Financing in Emerging Markets	January 2018
Note 47: From Farm to Fork: Private Enterprise Can Reduce Food Loss Through Climate-Smart Agriculture	October 2017
Note 46: Precision Farming Enables Climate-Smart Agribusiness	October 2017
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Note 23: Energy Storage—Business Solutions for Emerging Markets	November 2016
Note 22: Mitigating the Effects of De-Risking in Emerging Markets to Preserve Remittance Flows	November 2016
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Creating Markets, Creating Opportunities

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ACCELERATED GROWTH OF

RENEWABLES AND GAS POWER CAN RAPIDLY CHANGE THE TRAJECTORY ON CLIMATE CHANGE

EXECUTIVE SUMMARY

Addressing climate change must be an urgent global priority, requiring global action, national commitments, and consistent policy and regulatory frameworks.

Too often, the dialog around climate change can be mired in defining and debating an ideal future state and the timeline by which society would achieve that end-state. In the meantime, insufficient global progress is being made with each passing day. Paraphrasing an old adage, "Perfection is the enemy of progress."

Decarbonization* of the power sector and electrification of energy-use sectors (e.g., transportation, industry and heat) as quickly as possible will have the most substantial impact on global carbon emissions. Based on our extensive analysis and unique experience across the breadth of the global power industry, **GE believes that accelerated and strategic deployment of renewables and gas power can change the trajectory for climate change, enabling substantive reductions in emissions quickly, while in parallel continuing to advance the technologies for low or near zero-carbon power generation.**

GE also believes that decarbonization actions will be determined locally, based on resource availability, policy, current infrastructure, and demand for power. There are many regions in which gas power can be a key enabler to further renewables penetration, specifically in regions with high current gas capacity and/or substantial dependence on coal. In those regions, gas power can serve as a backbone for greater renewables penetration and accelerate the retirement of coal assets, both of which will have significant positive impact on overall emissions.

Renewables are the fastest growing source of new power generation capacity and electricity. This dramatic growth has been propelled by a combination of factors including public awareness about climate change, steep cost declines, advances in wind and solar technologies, and favorable policies that incentivize investment in renewable technologies. Yet despite the progress, today wind and solar together account for just 8 percent of global electricity generation and with all renewables considered (predominantly hydropower) it grows to nearly 27 percent.[1]

To put the challenge of relying solely on increased deployment of wind and solar PV to combat climate change into perspective, in the International Energy Agency's (IEA) Stated Policies Scenario, their reference scenario, wind and solar account for nearly 75 percent of global net capacity additions between now and 2040. This results in more than a 3X increase in wind, and 6X increase in solar installed capacity. Despite the rapid growth and significant investment in wind and solar PV postulated in this scenario, their combined generation contribution only increases to 28 percent of the global total in 2040 and they are roughly on par with coal at 22 percent and gas power at 21 percent.[2]

GE believes that the accelerated and strategic deployment of renewables and gas power can change the trajectory for climate change

New sources of abundant and affordable natural gas have driven the economic shift of coal-to-gas switching in several regions. With less than half the CO_2 of coal generation, natural gas is contributing significantly to decarbonization in these regions. Yet globally, coal still accounts for nearly 40 percent of electricity generated and it is expected to remain the largest single source of electricity generation for decades to come unless significant changes in the power sector fuel mix occur.

Viewed separately, renewables and gas generation technologies each have merits and challenges as a means to address climate change and optimum solutions will differ regionally. Such solutions will depend upon factors such as fuel availability and security, land use constraints, renewable resource availability, and the emphasis a particular region is placing on climate change. Together, their complementary nature offers tremendous potential to address climate change with the speed and scale the world requires. Key attributes of these technologies are summarized on the following page.

**Decarbonization in this paper is intended to mean the reduction of carbon emissions on a kilogram per megawatt hour basis.*

EXECUTIVE SUMMARY

TABLE 1: The complementary attributes of renewables and gas power

	WIND, SOLAR & STORAGE	GAS POWER
FUEL	Limitless, free fuel that is variable	Flexible, dispatchable power whenever needed, utilizing abundant & affordable natural gas or LNG
CO_2	Carbon-free generation	Less than half the CO_2 of coal generation with a pathway to future conversion to low or near-zero carbon with hydrogen and Carbon Capture and Sequestration (CCS)
COST	Competitive Levelized Cost of Electricity (LCOE) with no lifecycle uncertainty (mostly CAPEX)	Competitive LCOE with lowest CAPEX, providing affordable, dependable capacity
DISPATCH	Dispatches first in merit order... extremely low variable cost	Most affordable dispatchable technology... fills supply/demand gap
PEAKING	Battery storage economical for short duration peaking needs (<8 hour, intraday shifting)	Gas economical for longer-duration peaking needs (day-to-day and weather-related extended periods)
CAPACITY FACTORS	25%–55% capacity factors based on resources (wind and solar often complementary)	Capable of >90% capacity factors when needed, runs less based on variable costs & renewables
LAND	Utilizes abundant land with good renewable resources (multi-purpose land use); Offshore wind is not land constrained	Very small physical footprint for dense urban areas with space constraints
HYBRID SOLUTIONS	Extends renewable energy to align with peak demand	Carbon-free spinning reserve peaking plants using onsite battery storage

Technologies other than wind, solar, battery storage and gas will contribute as well to the longer-term power mix, but **the focus of this whitepaper is to elevate the emphasis on renewables and gas power as an urgently needed solution to change the near-term trajectory on climate change.**

The power industry has a responsibility, and the technical capability to take significant steps to quickly reduce greenhouse gas emissions and help address climate change at scale. The solution for the power sector is not an either/or proposition between renewables and natural gas, but rather a multi-pronged approach to decarbonization with renewables and natural gas power at its core. GE as a company is uniquely positioned to play a role through its scale, breadth, and technological depth.

Attributes of renewables and gas power are complementary, making them a powerful combination to address climate change

We have been a key player in the power industry since its inception and have a suite of complementary renewable, gas-fired, nuclear, grid and digital technologies needed for the transformation to a decarbonized energy future. This industry experience coupled with technological know-how enables GE to help policy makers to make effective decisions that deliver the desired decarbonization results while avoiding unintended consequences.

FRAMING THE CLIMATE CHALLENGE

There is broad scientific consensus that the concentration of CO_2 in the atmosphere is increasing, that the increase is due primarily to anthropogenic (man-made) sources, and that the higher concentration is causing an increase in global average temperatures. Although other greenhouse gases (GHGs) including methane, nitrous oxide, and fluorinated gases are also contributing to the increase in global temperatures, CO_2 is the largest single contributor, accounting for more than 75 percent of all GHGs.

THE POWER INDUSTRY CAN'T DO IT ALONE: CROSS SECTOR SOLUTIONS NEEDED

Forty one percent (13.7 Gigatonnes or Gt) of the global CO_2 emissions from fuel combustion are attributable to the electricity and heat production sector. This is followed by the industry and transport sectors, with 26 percent and 25 percent respectively.[3] See Figure 1. Although there has been significant attention, and some progress addressing CO_2 emissions in the power sector, there has not been as much focus or progress in other sectors. As an example of non-power sector initiatives, GE supports the aviation industry's plan to achieve a net reduction in aviation CO_2 emissions of 50 percent by 2050, relative to 2005 levels. GE invests $1 billion annually to accelerate technology innovations needed to drive reduction in carbon emissions that help make flying increasingly sustainable.

If power sector CO_2 emissions could somehow be brought immediately to zero—an impossibility—that would not realize the COP 21 Paris Agreement goal of keeping the global average temperature increase to less than 2°C.

Emission reductions are needed across all sectors, but the power sector can and should make whatever reductions it can by deploying as much renewables as possible supported by a combination of coal-to-gas switching, deployment of new gas-fired power plants and efficiency upgrades to existing gas-fired plants.

Another method for reducing power sector emissions is through reduced electricity consumption. Demand-side energy efficiency is sometimes called the first fuel, or the fuel you don't need to use, and is often expressed in terms of electrical intensity. This metric is defined as the amount of electricity consumed per unit of gross domestic product (GDP), and it has been on a steady global decline for several decades due to things such as more efficient home appliances, LED light bulbs, and energy conservation measures.

CO_2 Emissions by Sector (33.7 Gt Total)

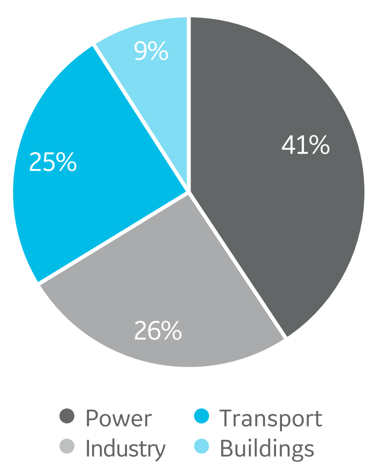


FIGURE 1: The power sector produces the largest amount of CO_2 emissions, but all sectors need to address CO_2 emissions.

Continuing these energy efficiency efforts will help to reduce the need for additional generation across the power sector. The "Future is Electric" scenario from the IEA's 2018 World Energy Outlook[4] postulates that widespread deployment of currently available technologies could take the proportion of electricity in final energy use from 19 percent to a maximum technical potential of around 65 percent. This would happen, for example, if heat pumps become widespread in industry and buildings, if electric vehicles (EVs) become the vehicle of choice, if induction stoves become the sole choice for cooking, and so on. The potential for higher electrification therefore is very large, even though around 35 percent of final consumption would still require other energy sources, including most shipping, aviation and certain industrial processes.

Electrification by itself will not deliver on sustainability goals. Although switching from combustion of fuels to electricity has clear environmental advantages at the point of use due to reduced emissions of local air pollutants, the overall environmental impact needs to be considered at the system level. **Simply shifting from tailpipe emissions from an internal combustion engine to smokestack emissions from a coal power plant providing electricity to an EV does not necessarily reduce, and in some locations could increase, system CO_2 emissions.** For electrification to be most effective at reducing CO_2 emissions there needs to be a concurrent shift in the makeup of the fuel sources of the power sector such as coal-to-gas switching immediately and continuing the pursuit of low or zero-carbon sources. This concurrent shift, combined with electrification, would then enable significant reductions across the largest CO_2 emitting sectors of the economy, namely power, transportation, and industry.

AFFORDABLE, RELIABLE AND SUSTAINABLE ENERGY IS A BASIC HUMAN RIGHT

Access to affordable, reliable, and sustainable energy is critical to growing economies and is fundamental to the quality of life in the modern world. According to the IEA, roughly 770 million people lack access to reliable electricity, and more than 2.6 billion do not have access to clean cooking fuel, relying primarily on biomass (wood, charcoal, dung, etc.). Universal access to modern energy by 2030, including electricity and clean cooking, is one of the key pillars of the United Nations' Sustainable Development Agenda (SDG 7).[5] See Figure 2.

In addition to the challenge of addressing basic energy access, the global middle class is now more than half of the world's total population—more than doubling since 2010—and is expected to reach 5.3 billion by 2030. Most of this growth is expected to occur in Asia.[6] The continent has some of the most densely populated cities in the world, and the power density of gas power makes it well suited to providing power at scale, in close proximity to demand. As people join the middle class, they purchase more energy intensive products such as air conditioners, refrigerators and other home appliances, thereby increasing electricity demand. The IEA projects that total electricity demand will rise globally by nearly 50 percent through 2040.[7]

Energy Trilemma

ELECTRICITY GENERATION, DELIVERY & CONSUMPTION

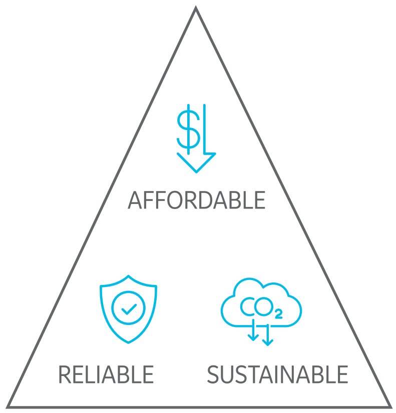


FIGURE 2: The energy trilemma is the challenge of providing affordable, reliable and sustainable energy.

The most effective way to ensure power system reliability and energy security is through a mix of generation sources. No single form of power generation is optimal in every situation or economy. For example: wind and solar are variable but consume no fuel and emit no CO_2; natural gas-fueled generation emits CO_2 but is dispatchable (i.e., has output that can be readily controlled between maximum rated capacity or decreased to zero) to help balance supply and demand; hydro power often requires dedicating significant amounts of land area but is zero-carbon, renewable and dispatchable, and can provide long-term, low-cost energy storage.

A mix of generation sources is the most effective way to provide system reliability and energy security

THE AGE OF RENEWABLES

Renewable power is carbon-free, uses an infinite supply of free fuel that is not subject to price fluctuations, and produces very low cost electricity. These attributes make the deployment of renewables the core element in combatting climate change, leading to tremendous growth in capacity additions since the turn of the century—especially in wind and solar PV. This explosive growth has been driven primarily by reductions in cost, technology advancements to improve capacity factors, favorable policies and positive public sentiment around zero-carbon energy. In some locations with abundant wind and solar resources, renewable technologies have become cost-advantaged relative to thermal power generation on an LCOE basis. The biggest perceived drawback of wind and solar, the fact that they are variable, is mitigated by the fact that with modern weather forecasting methods they are largely predictable.

Despite massive renewables investment, coal generation is down only ~10% and gas generation is up ~33% through 2040.

Global installed capacity of renewables has grown from approximately 1 GW of solar PV and 17 GW of wind in 2000 to approximately 650 GW of each today.[8] 2019 was an unprecedented year for global renewable capacity orders, eclipsing the 200 GW mark for the first time.[9] The cumulative effect of nearly two decades of renewables orders growth resulted in 27 percent of global electricity supply coming from renewable sources in 2019.[10] This growth is expected to continue

CAPACITY ADDITIONS FORECAST AND RESULTING GENERATION EVOLUTION

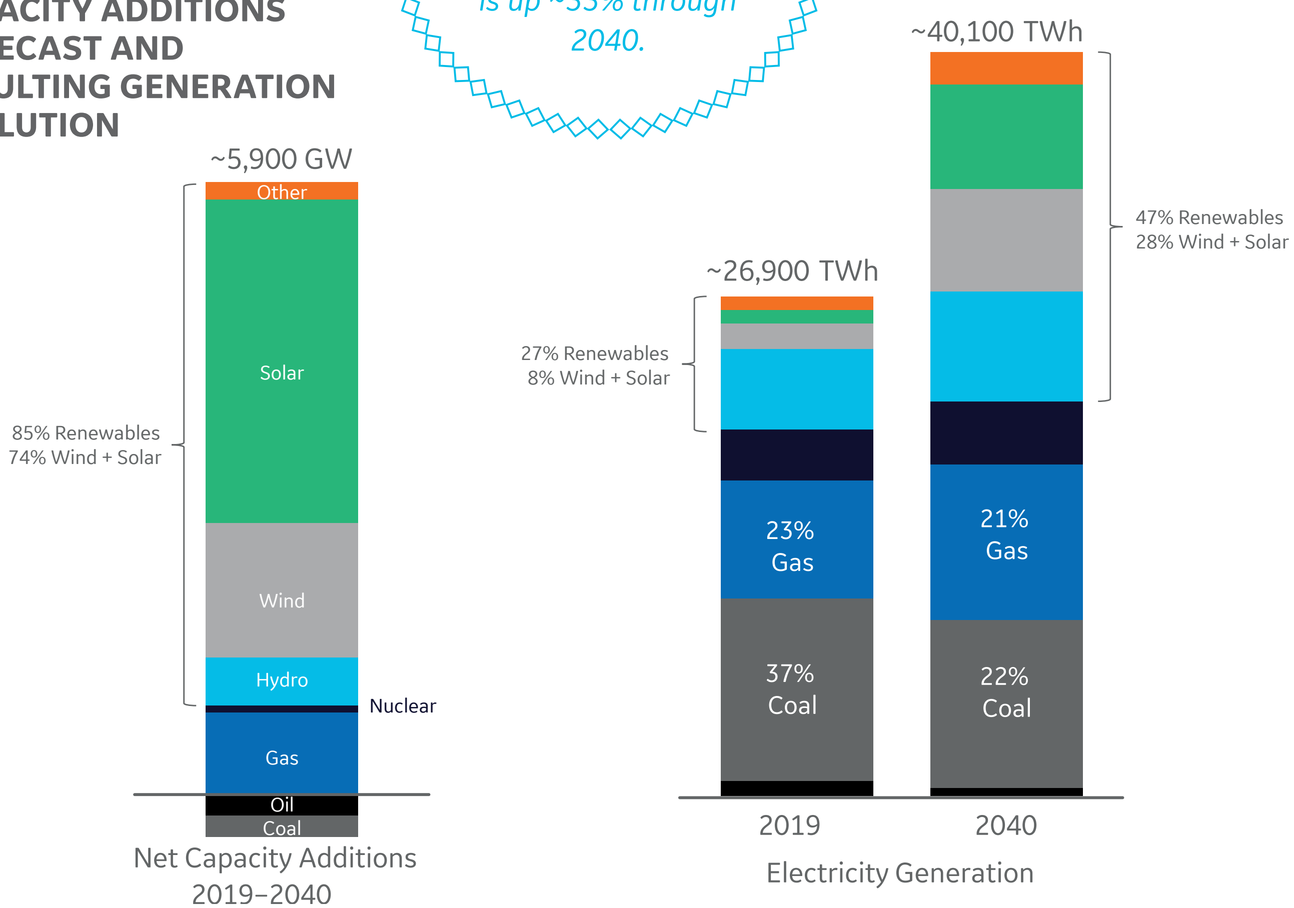


FIGURE 3: Net capacity additions and resulting change in electricity generation 2019 to 2040…despite aggressive renewables net additions, they are insufficient to result in a meaningful reduction in absolute global coal generation by 2040.

Source: IEA World Energy Outlook 2020 Stated Policies Scenario

LCOE reductions in wind and solar are expected to continue, driven by lower CAPEX and improved capacity factors

and accelerate, with solar PV capacity growing approximately 6X to more than 3,600 GW, and wind capacity more than 3X to 1,900 GW by 2040, according to the IEA's reference Stated Policies Scenario. An additional two decades of renewables growth will result in more than a 2.6X increase in electricity generation from renewable sources, accounting for 47 percent of the total global electricity supply in 2040.[11]

Yet despite wind and solar accounting for nearly 75% of global net capacity additions between now and 2040, the industry needs to do more to reduce global generation from coal to meet decarbonization goals. See Figure 3.

The cost drivers behind the rapid growth in renewables deployment are expected to continue. Figure 4 demonstrates how the LCOE of onshore wind and utility scale solar PV are expected to continue to drop between 2020 and 2040. As examples, the LCOE for onshore wind in Brazil is expected to drop 31 percent during this period and solar PV in Germany is expected to drop 50 percent. In fact, the average reduction in onshore wind LCOE for the five diverse countries shown is 32 percent, and for solar PV it is 49 percent.[12] A main driver for these reductions in LCOE is a reduction in CAPEX as supply chains benefit from increasing scale and an accelerating learning curve. A key outcome of the reduction in CAPEX is the ability to accelerate renewables deployment because a fixed amount of investment purchases more capacity.

Advances in technology have also contributed to the reduction in LCOE. Wind turbines are getting more efficient at low wind speeds. The towers are getting taller and blade diameters larger, enabling them to produce more energy from a given piece of land. Capacity factors are also improving, with new onshore wind farms now operating at up to 35 percent capacity factor and new offshore wind farms at up to 55 percent capacity factor.[13]

Offshore wind energy holds the promise of significant environmental and economic benefits. It is an abundant, low-carbon energy resource located close to major coastal load centers, and in many cases provides an alternative to long-distance transmission or development of electricity generation in these land-constrained regions. Moreover, offshore wind LCOE keeps dropping yearly, with GE's most efficient designs achieving a capacity factor of 63%.

Offshore wind is an affordable, renewable source of energy that can be deployed at a scale capable of providing as much capacity as thermal and nuclear power plants. The IEA has highlighted its almost limitless potential, and the Ocean Renewable Energy Action Coalition (OREAC) estimates the world can deploy 1.4TW by 2050.[14] Offshore wind is an undeniable pillar in the energy mix, a here-and-now technology contributing to decarbonization and limiting increases in global average temperatures.

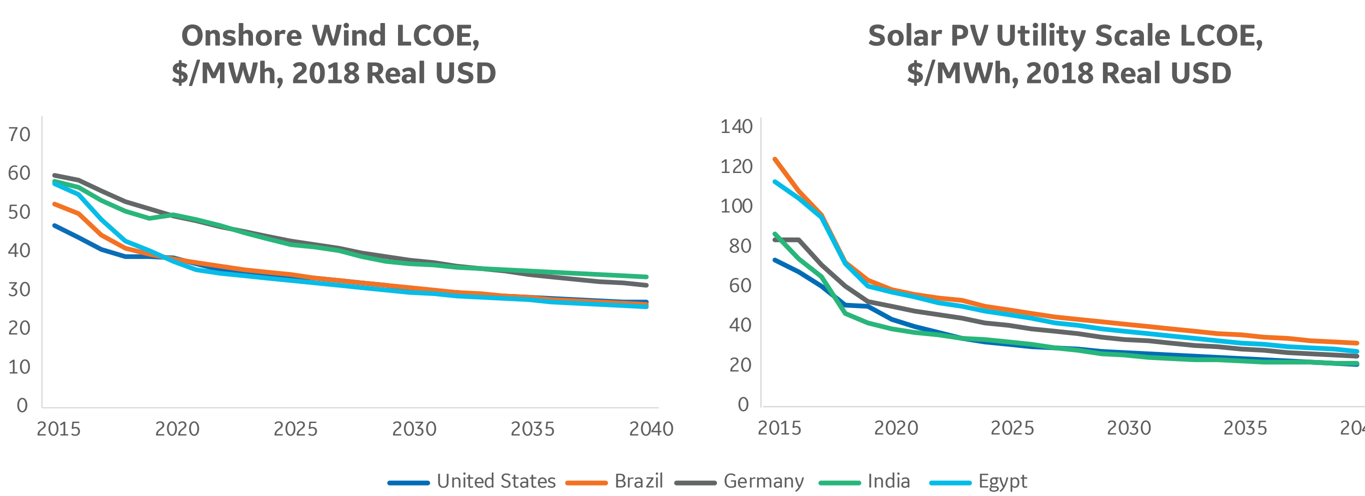


FIGURE 4: LCOE of Onshore Wind and Utility Scale Solar PV are expected to continue to drop.

Source: IHS Markit, Global Renewable Levelized Cost of Electricity Outlook Part 1, February 2020. ©2020 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior permission by IHS Markit.

Strong grids and energy storage systems are key to compensating for the variable nature of wind and solar generation. Although in some locations wind and solar generation are complementary, i.e., solar generation is available during the day and wind generation is more prevalent at night, modern power systems must match supply and demand in real time and provide 24/7/365 reliability.

Very high penetration of renewables generation could lead to system instability if grid operators don't mitigate the variability of the resource via a combination of storage, complementary gas generation, demand side management, grid infrastructure investment, and other strategies.

Lithium-ion (Li-ion) battery energy storage system (BESS) technology has made great strides in CAPEX reductions resulting in the potential to significantly improve the dispatchability of wind and solar generation to provide required grid reliability.

The CAPEX of Li-ion batteries has come down substantially in recent years and this cost reduction trajectory is expected to continue. See Figure 5. Utility-scale battery systems have benefited from the massive build-up of battery capacity to support the electric vehicle market, and the CAPEX of a 4-hour BESS is expected to drop an additional 50 percent between 2020 and 2040.[15]

Li-ion battery storage has become an attractive and economical approach for intra-day (typically <8 hours) storage of renewables. Utility scale batteries are now being deployed to provide grid ancillary services and to defer transmission investments. The economics can be justified because in intra-day applications the battery charges and discharges, and creates value daily, or even multiple times within a day. The battery CAPEX for this intra-day shifting is therefore monetized over many charge/discharge cycles. Using batteries to shift energy from perhaps a weekend when the sun is shining but demand is low to a weekday when demand is higher will reduce the number of charge/discharge cycles over which to monetize the battery CAPEX. The relationship of CAPEX to the Levelized Cost of Storage (LCOS) is such that if the number of charge/discharge cycles is cut in half, the LCOS doubles. **Battery storage will not be competitive on an LCOS basis for durations greater than 8 hours until there is a significant technology breakthrough resulting in a reduction in cost.** Until a battery technology breakthrough occurs, gas power remains the most cost effective backup for large, multi-day shortfalls in the supply of renewable energy.

Batteries can also be deployed effectively in a hybrid power plant in which a BESS is integrated directly with one or more forms of power generation such as wind, solar, or a gas turbine power plant. This type of application leverages the best attributes of each technology and can help provide vital grid stability services such as frequency regulation, spinning reserve capacity, or black start capability, and several hybrid BESS systems are in operation today.

Battery storage has become economical for intra-day storage of renewables but not yet for longer periods

Battery Storage CAPEX, Li-ion 4 Hour $/kW, 2018 Real USD

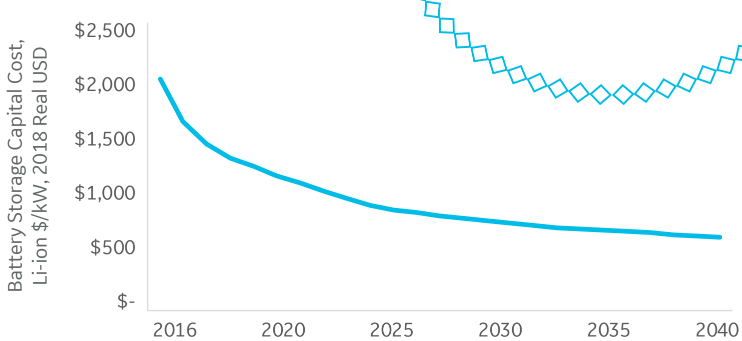


FIGURE 5: The CAPEX of Li-ion battery storage systems has dropped substantially and is expected to continue to drop. *Source: IHS Markit, US Battery Storage Capital and Levelized Cost Outlook, January 2020. ©2020 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.*

Gas plants are capable of compensating for long gaps in renewable production in ways that today's battery storage technology cannot

COAL IS DOWN, BUT NOT OUT

As the international community moves toward a decarbonized future, the ideal generation mix will depend on an individual country's available fuel resources, its point in the journey to a decarbonized future, and the often-competing goals of providing reliable, affordable and sustainable energy to a growing population that aspires to improved standards of living.

Coal is the largest fuel source for electricity generation in the world today, accounting for 37 percent of the total.[16] Despite well publicized retirements of coal-fired capacity in the United States and Western Europe, **there are still more than 2,000 GW of coal power plants installed globally, making up nearly 30 percent of global installed capacity, and nearly 400 GW in the United States and Western Europe alone.** Approximately 1,400 GW of new coal-fired power plants have been put on order globally since the turn of the century, mostly in China during the 2000-2010 timeframe. In recent years there has been a dramatic slowdown in orders for new coal power plants due in large part to utilities responding to the negative public perception of coal, and reductions in available sources of finance from entities such as export credit agencies, pension funds, and private equity. Despite the retirements and recent orders slowdown, there remains a large installed base of coal power plants globally and it is expected that there will still be nearly 2,000 GW of coal plants in operation at the end of this decade.[17]

Global CO_2 emissions from coal power has been increasing for decades, but with a leveling off of coal power generation due to coal-to-gas switching, increased renewables generation, reduced operation and retirement of coal power plants, policy mandates, and the impact on demand due to the COVID-19 pandemic, global coal power CO_2 emissions likely have already reached their peak. Since 2010, coal power CO_2 emissions have come down more than 46 percent, and 31 percent in the USA and Europe, respectively. See Figure 6. These trends are expected to continue, and in the IEA's Stated Policies Scenario the USA's coal power CO_2 emissions come down 77 percent by 2030 relative to the 2010 baseline year and Europe's come down 74 percent.[18] Despite the gains in these regions, there is the potential to reduce coal power CO_2 emissions even further by running the installed gas power fleet more and strategic deployment of new gas power and renewables.

Coal in 2040: 22% of total global electricity and 68% of power sector CO_2

SOURCE: IEA WEO 2020

China and the rest of the world (ROW), however, have experienced increases in coal power CO_2 emissions since 2010. Coal power CO_2 emissions in China are up approximately 44 percent since 2010 and the ROW is up 27 percent. Coal power emissions are expected to level off in China and ROW near the end of this decade, leaving both with enormous potential to further reduce CO_2 emissions from coal.

Looking out a decade further, to 2040, coal power is expected to provide 22 percent of global electricity generation and be responsible for 68 percent (8.5 Gt) of power sector CO_2 emissions, according to the IEA.[19]

Emissions from coal at this level are inconsistent with achieving the goal of reducing global warming and more aggressive actions are needed, including deployment of carbon capture, utilization and storage (CCUS) at coal power plants, increased utilization of existing gas power, and increased deployment of new gas power and renewables.

POWER SECTOR COAL EMISSIONS TRAJECTORY

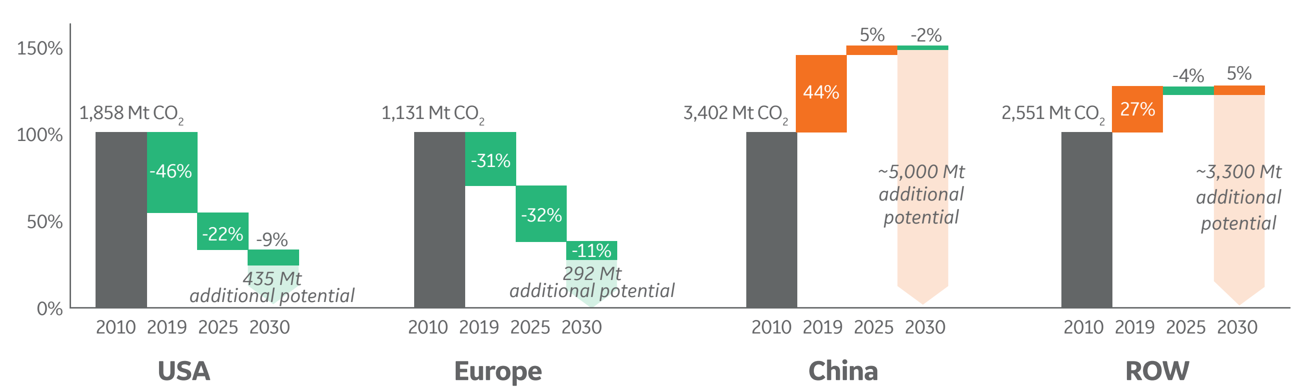


FIGURE 6: The USA and Europe are on a trajectory to reduce coal power CO_2 emissions significantly through retirements and decreased operation, but there is an opportunity for further reductions. China and ROW are still on a trajectory of increasing coal power emissions and need to reverse course. *Source: IEA World Energy Outlook 2020 Stated Policies Scenario*

The world is better served by accelerating renewables deployment, running existing gas plants more, and adding new gas capacity as the industry reduces coal generation

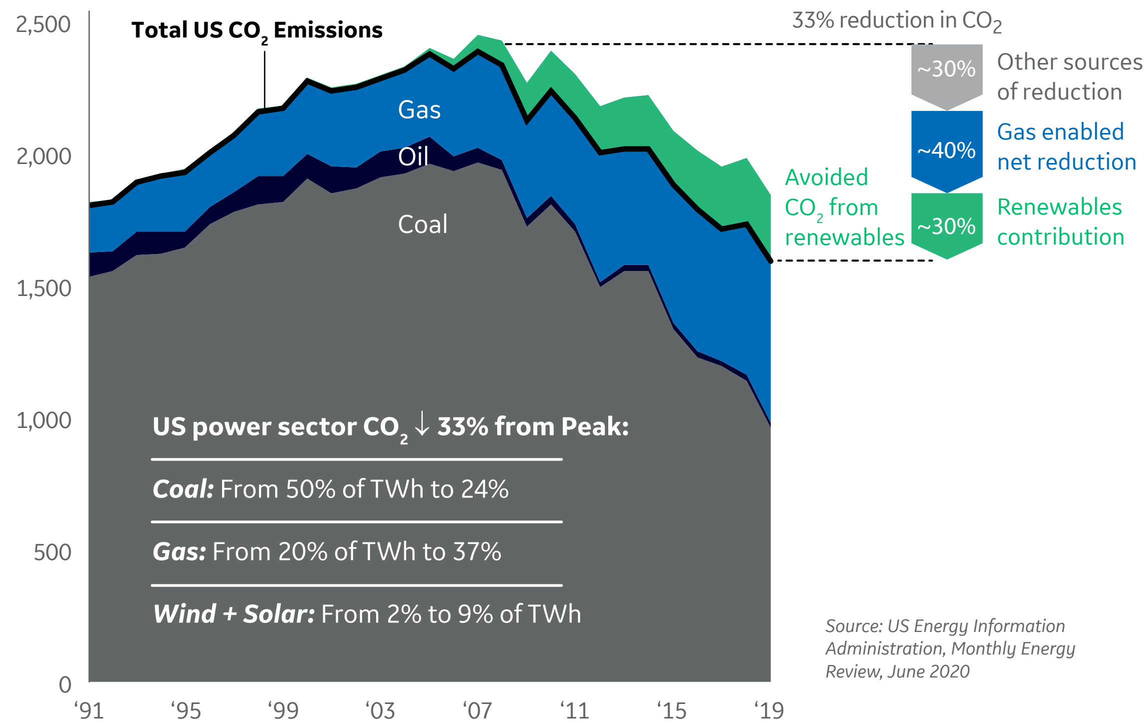
A POWERFUL COMBINATION – RENEWABLES PLUS GAS-FIRED POWER

GE believes in and promotes additional renewables capacity, augmented where needed with natural gas generation to provide system flexibility and dependable capacity, as the most effective near-term action to decarbonize the energy sector. Despite the massive deployment of wind and solar capacity in recent years, increases are not occurring at the pace or scale needed to decarbonize the electricity sector and meet the goals of the Paris Agreement. According to the IEA, given the time it takes to build up new renewables and to implement energy efficiency improvements, coal-to-gas switching represents a potential quick win for emissions reductions. There is potential in today's power sector to immediately reduce up to 1.2 Gt/yr of CO_2 emissions by running existing gas-fired plants harder and reducing coal use commensurately. There is additional opportunity to reduce coal emissions by retiring existing coal-fired capacity and replacing it with new, high efficiency combined cycle capacity. Doing so would almost immediately bring down global power sector emissions by 10 percent and total energy-related CO_2 emissions by 4 percent.[20]

> *Given the time it takes to deploy new renewables and to implement energy efficiency improvements, coal-to-gas switching represents a potential quick win for emissions reductions.*
>
> SOURCE: IEA SPECIAL REPORT, THE ROLE OF GAS IN TODAY'S ENERGY TRANSITIONS, JULY 2019

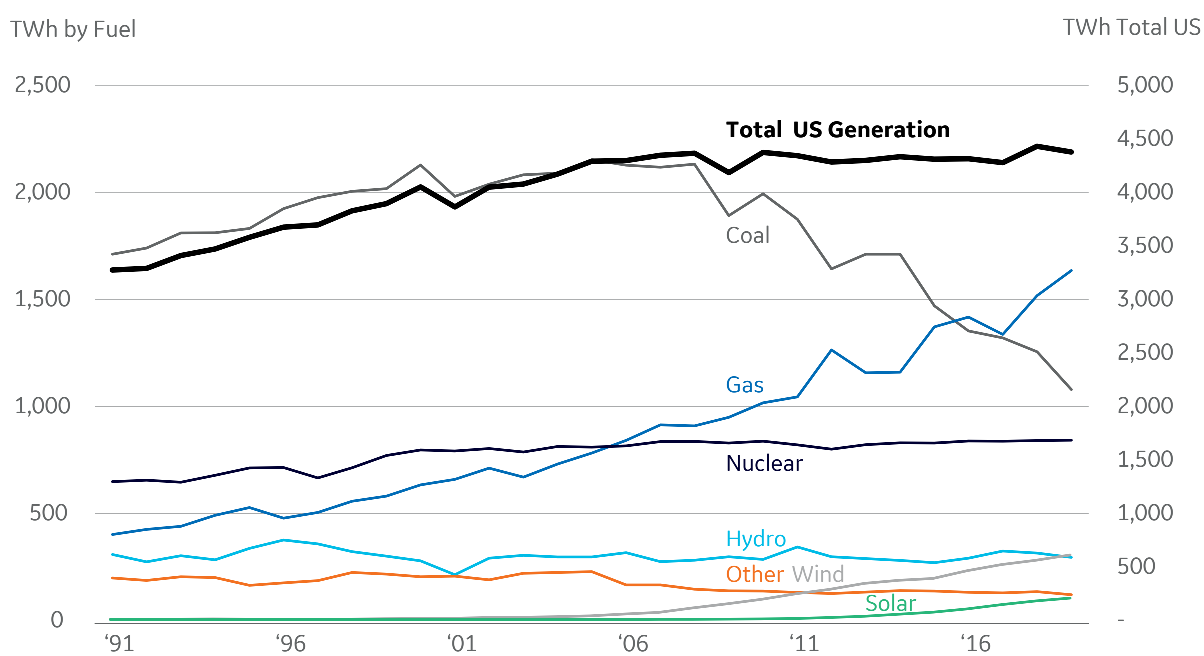
The United States is a powerful example of the pace and scale that renewables and gas power can lead to decarbonization of a power sector that was heavily dependent on coal. Since the peak in 2007, power sector CO_2 emissions in the United States have dropped 33 percent while total electricity generation remained fairly constant at approximately 4,300 TWh. During this time, coal generation dropped roughly in half, from 50 percent to 24 percent, while gas generation increased from 20 percent to 37 percent, and wind and solar grew from less than 1 percent to 9 percent.[21] The emissions reduction attributed to coal-to-gas switching was greater than that from any other fuel source. See Figure 7 on the following page.

US POWER SECTOR CO2 (Million Metric Tons)



Source: US Energy Information Administration, Monthly Energy Review, June 2020

US ELECTRICITY GENERATION BY FUEL



Source: GE Gas Power Global Power Outlook 2020

FIGURE 7: Coal-to-gas switching is contributing more to power sector carbon reduction in the US than any other generation technology.

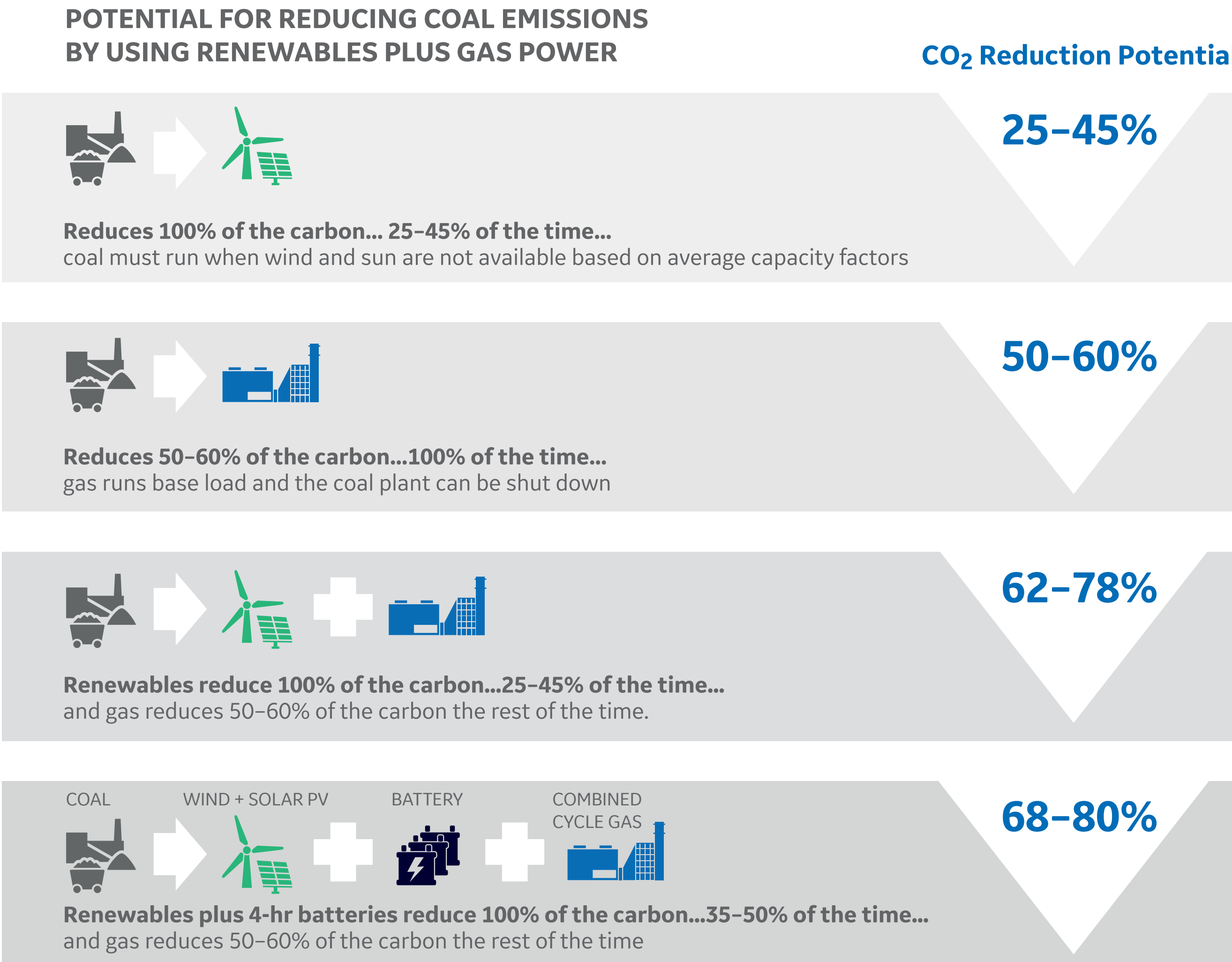


FIGURE 8: Replacing baseload coal with a combination of renewables and gas yields the quickest carbon reduction at scale. Note that CAPEX and required land are not addressed in the above analysis.

On a global scale, replacing coal with a combination of variable renewables and batteries plus dispatchable gas yields greater carbon reduction than renewables alone. An analysis done by GE and summarized in Figure 8 considers the real-time balancing of power supply and demand using a hypothetical base loaded coal plant as an example.

Because of the variable nature of wind and solar energy, and lower capacity factors for these technologies, a direct replacement of coal with wind and solar would eliminate approximately 25–45 percent of the coal CO_2 emissions. That said, the coal plant would still need to provide energy, and thereby emit CO_2, when wind and solar are not available.

Replacing the coal plant with base load natural gas alone would reduce CO_2 emissions by approximately 50–60 percent for 100 percent of the time due to the lower CO_2 intensity of natural gas.

Replacing the coal plant with a complementary mix of wind and solar plus natural gas, however, enables the wind and solar to provide zero-carbon energy whenever they are available, with combined cycle gas turbine plants making up any remaining energy needs. This results in approximately a 62–78 percent reduction in overall system CO_2.

Replacing the coal plant with a complementary mix of wind, solar, and 4-hour batteries, plus natural gas enables the wind and solar to provide zero-carbon energy for 35–50 percent of the time, with combined cycle gas turbine plants making up any remaining energy needs. This maximizes the energy from the renewables sources and results in approximately a 68–80 percent reduction in overall system CO_2.[22]

GAS POWER ENABLES MORE RENEWABLES

Natural gas-fired power generation is flexible and dispatchable. Plants can come online quickly, adjust power output level, and turn down to a very low output level to balance supply and demand as needed. They can deliver more power or less as supply and demand for electricity vary throughout the day, over the course of a week or month, and seasonally—whenever required. This flexibility is especially important to maintain grid stability as more non-dispatchable wind and solar resources are deployed.

Gas-fired power plants are available regardless of the time of day or weather conditions, providing dependable capacity as long as needed, whether for minutes, hours, days or weeks at a time. Wind and solar power are available when the wind is blowing or the sun is shining. The availability of the wind and solar resources does not always coincide with demand. Because electricity supply and demand must always be in balance, renewables require dispatchable backup power such as natural gas power plants or batteries to ensure system reliability. The Dependable Capacity metric shown in Figure 9 has been developed by GE to illustrate the ability of a technology to reliably produce electricity during summer or winter daytime and nighttime peaks considering nameplate capacity, degradation due to ambient temperature effects, and the coincidence of a renewable generation source to peak demand. The values shown are global averages.

Average Dependable Capacity

Gas	84%
Coal	78%
Nuclear	92%
Hydro	63%
Wind	14% Onshore, 27% Offshore
Solar	20–40%

FIGURE 9: Average dependable capacity of various generation technologies.[23]

Nuclear remains an important part of the power generation landscape and is contributing to the transition to cleaner energy as the most dependable source of CO_2-free power. Today nuclear power delivers approximately 10% of the world's electricity with more than 400 GW in the global installed base. While there are plans to phase out nuclear power in some countries, forecasts show around 10 GW/yr of future demand for new nuclear plants although the timing is uncertain.

Typical CAPEX Cost $/kW

Gas – CC	~$700–$1,200
Coal	~$5,000
Nuclear	~$8,000
OnshoreWind	~$1,500
Solar PV	~$1,250
Battery	~$1,200/kW (4-hour)

FIGURE 10: Gas power is the lowest cost generation technology on a $/kw basis.[24]

Gas power is affordable due to its low CAPEX requirements and the availability of abundant, cost competitive natural gas. In fact, it is currently the lowest cost generation technology on a $/kW basis. This is especially important when access to capital is constrained or project financing is required. See Figure 10.

Gas can provide affordable baseload power in developing, high-growth regions, and then transition to economic and complementary cyclic or peaking power as needed to accommodate future renewables growth.

Gas power is affordable, efficient and dispatchable as a means to complement renewables, with less than 50% of the CO_2 emissions compared to coal

LAND USE IS AN IMPORTANT FACTOR

Modern society requires vast amounts of electricity to function, and one of the greatest challenges we face today is providing electricity that is affordable, reliable and sustainable on a planet with a growing population that requires more land. **Land is an increasingly scarce global resource that is subject to competing pressures from agriculture, human settlement, and energy development. Renewables sources such as wind and solar PV are less power dense than natural gas power,** meaning that they require more land per unit of installed generating capacity or unit of electricity produced.

The low power density of wind, solar PV and battery storage is not an impediment in parts of the world where land is plentiful and the demand for electricity is in relatively close proximity to the renewable supply. Where this is not the case, there can be a conflict between electricity production and other land uses. Using the United States as an example, the relatively densely populated east and west coasts make locating utility scale onshore wind farms a challenge, but in the less populated central plains (e.g., Iowa) this is less of an issue. Similarly, solar PV can be located in the desert southwest (e.g., Arizona) where the solar resource is abundant and vast tracts of land are available with little or no competing uses. In both examples the transmission of the electricity from where it is generated to where it is consumed needs to be considered and new infrastructure such as high-voltage direct current transmission lines may be required.

Offshore wind has the potential to address land use challenges in some regions. A recent analysis by the IEA examined the technical potential of all marine areas within 300 kilometers of shore using the newest turbine designs. Tapping just the most attractive sites in near-shore shallow waters could provide nearly 36,000 TWh of electricity, nearly 90 percent of the total global electricity demand expected in 2040. Realizing this potential, however, will require trillions in investment dollars, careful planning, efficient supply chains, and transmission infrastructure capable of bringing the electricity onshore.[25]

Significantly less space is required for gas-fired generation, enabling natural gas power plants to be deployed closer to demand centers and possibly avoiding the need for an investment in transmission infrastructure. Figure 11 demonstrates the amount of land needed to provide 1,000 MW of power generation capacity using different technologies.[26]

Available land could become a barrier to a 100 percent renewable power sector in certain locations, particularly major cities, and will become increasingly challenging as the world's population grows. A more practical approach is to strategically deploy a combination of wind, solar PV, batteries and natural gas-fired power plants that enable decarbonization at a pace and scale greater than can be achieved by renewables alone, while minimizing the amount of valuable land required.

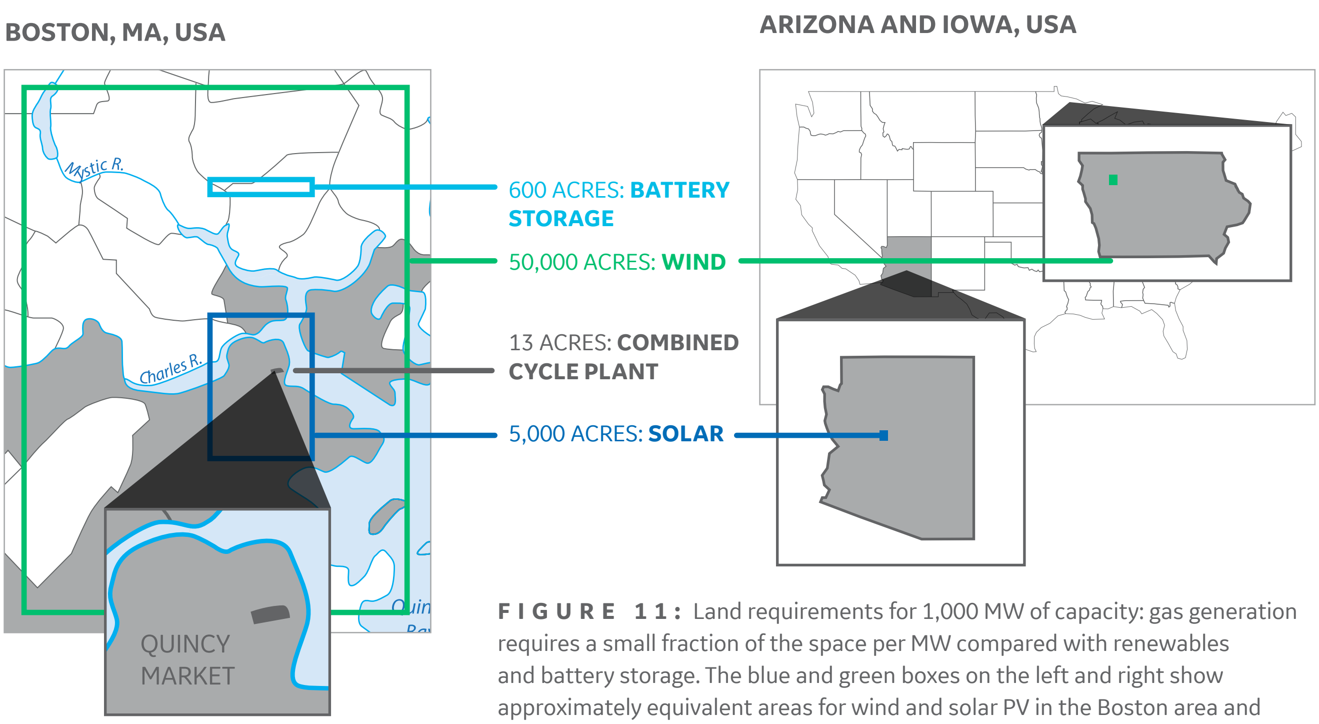


FIGURE 11: Land requirements for 1,000 MW of capacity: gas generation requires a small fraction of the space per MW compared with renewables and battery storage. The blue and green boxes on the left and right show approximately equivalent areas for wind and solar PV in the Boston area and less populated regions.

Gas power can be deployed quickly and at scale

NATURAL GAS IS ABUNDANT, AVAILABLE AND AFFORDABLE

Natural gas availability has increased dramatically with the advent of new methods for oil & gas production and a sharp increase in global gas liquefaction and regasification capacity. **The IEA projects that global natural gas production could increase nearly 30 percent by 2040 from 2019 levels and that USA wholesale prices remain below $4.20 ($2019) throughout the period.[27]**

According to IHS Markit, 2019 was a record year for global liquefied natural gas (LNG) on several fronts. Arguably, the most important of these is the amount of liquefaction capacity that was sanctioned in 2019, reaching a Final Investment Decision (FID). 70.4 Mtpa (millions of tons per annum) reached FID compared to the prior all-time high of 20 Mtpa in 2005. Most of this new liquefaction capacity will be in the US, Russia and Mozambique. Similarly, a record 38.8 Mtpa of new liquefaction capacity reached commercial operation in 2019, an increase of nearly 10 percent in global capacity.[28] In fact, the IEA expects globally traded LNG to grow nearly 80 percent by 2040.[29]

At the onset of 2020, the International Gas Union reported that there were 120 Mtpa of regasification capacity under construction, which will add about 15 percent to global capacity. When these facilities become operational, the number of countries with regasification capacity will exceed 42.[30]

The result of the new gas production methods and expansion of both liquefaction and regasification capacity is a natural gas fuel resource that is expected to be available at relatively low and stable prices for the foreseeable future.

Globally traded LNG is expected to grow nearly 80% by 2040.

SOURCE: IEA WEO 2020

RENEWABLES AND GAS POWER CAN BE DEPLOYED QUICKLY

The key to combatting climate change in the power sector is to make significant changes to the generation mix toward renewables and gas power quickly and at scale. **Natural gas power plants can be deployed more quickly than any other form of dispatchable, utility scale power.** A trailer mounted aeroderivative gas power plant rated at 30 MW can be deployed anywhere in the world in a manner of weeks to months to address emergency needs. Simple cycle gas power plants can be in commercial operation 6–12 months after notice to proceed is received. Combined cycle power plants rated at 1GW or more take 24–36 months to be brought into commercial operation. Wind and solar power can also be deployed quickly, typically generating power in as little as 6–12 months from notice to proceed.

These short deployment times mean that renewables and gas can be contributing to CO_2 reductions quickly and at scale, while generating revenue, and less capital is tied up during the construction phase of a project.

GAS TURBINES HAVE A PATHWAY TO LOW OR ZERO-CARBON EMISSIONS

Existing and future gas power plants can be decarbonized and avoid CO_2 "lock-in" by using hydrogen as a fuel or employing carbon capture

Natural gas-fired combined cycle power plants are the lowest emitting fossil fuel power plants, whether measured based on CO_2, SO_x, NO_x, particulate matter, or mercury. Going forward, however, there will be a need to reduce CO_2 emissions further and there is a concern that deploying new gas generation capacity will "lock in" CO_2 emissions for the lifetime of the power plant. Gas turbines currently in operation or yet to be deployed have a pathway to enabling decarbonization and avoiding lock in of CO_2 through utilization of hydrogen as a fuel or through carbon capture technologies. See Figure 12.

One method to reduce CO_2 emissions from gas turbines is to mix hydrogen with natural gas. "Green" hydrogen, which generates no carbon emissions, is produced by electrolyzing water using renewable energy as the energy source. The hydrogen produced in this manner serves effectively as an energy storage mechanism enabling the renewable energy to be stored in the form of hydrogen for later use in a gas turbine.

Gas turbines have been running for decades on high hydrogen/ low Btu gases. State-of-the-art HA gas turbines are currently capable of burning up to 50 percent hydrogen by volume when blended with natural gas, and work is underway to develop capability for 100 percent hydrogen in these machines by the end of the decade. It should be noted that mixing hydrogen and natural gas at a 50/50 volume ratio does not result in a 50 percent reduction in CO_2 emissions. In fact, because of the lower density and lower specific energy of hydrogen, a 50/50 mixture of hydrogen and natural gas by volume only reduces CO_2 emissions by approximately 25 percent relative to a gas turbine without hydrogen blended with natural gas. To achieve a 50 percent reduction in CO_2 would require approximately a 75/25 hydrogen/natural gas mixture by volume.[31]

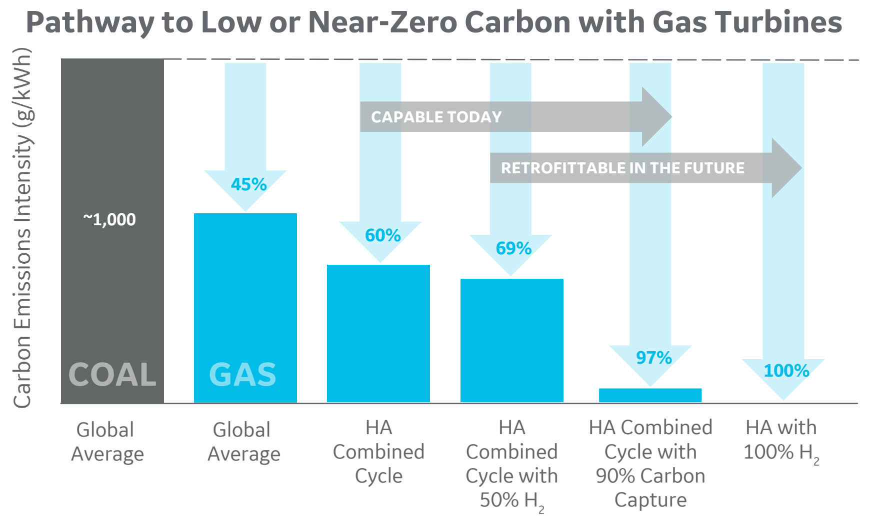


FIGURE 12: Gas turbine decarbonization opportunity

A potential benefit of using hydrogen as a fuel in gas turbines, either as a blend with natural gas or at 100 percent hydrogen, is that it can be accomplished either as a new build or on a retrofit basis, with relatively minor changes to the gas turbine and plant auxiliary equipment. Therefore, the decision to build a gas-fired power plant today does not necessarily lock in CO_2 emissions at the original level for the entire life of the power plant.

Future cost and technology breakthroughs may make hydrogen competitive as a zero-carbon dispatchable fuel source to complement renewables. Policies and incentives are being implemented in several countries to foster development of hydrogen infrastructure and drive down costs. These have the potential to significantly increase the availability and affordability of hydrogen, similar to what the wind and solar PV industries experienced through targeted policies and incentives.

Another pathway to net-zero carbon emissions for a gas turbine is through the use of either liquid or gaseous biofuels. Gas turbines are capable today of burning a wide variety of these carbon-neutral fuels.

Carbon capture or using hydrogen as a fuel are currently viable methods to decarbonize existing and future gas turbine power plants.

CCUS also has the potential to significantly reduce CO_2 emissions from all fossil fuel burning power generation and industrial processes. The Amine process is the most mature CCUS technology, with the capability to remove up to 90 percent of the CO_2 from an exhaust stream. Pilot projects are in operation today. Drawbacks include a near doubling of the upfront CAPEX of a power plant, additional space requirements, and a reduction in generation efficiency of almost 10 percentage points. Factoring in the additional cost and reduced efficiency results in an increase in LCOE of 30 percent to 50 percent.[32] Efforts are underway to optimize the power plant and CCUS thermal needs such that the impact on efficiency is reduced, and a price on carbon could make CCUS an economic option even with the increase in LCOE. Again, targeted CCUS policies and incentives, or a price on CO_2 emissions, could be the catalyst needed to foster technological innovation leading to reduced costs and widespread deployment of CCUS technologies.

Merely separating CO_2 is insufficient to reach deep decarbonization goals. It must be either used or stored safely and permanently. Public perception that captured CO_2 cannot be sequestered permanently is one of the biggest impediments to CCUS. Based on parallels to fossil fuel extraction technologies there is a strong technical basis that the **Earth has the capacity to store more CO_2 than humans can produce, and there is very strong evidence that we can safely store the CO_2 underground for hundreds of millions of years.** Every CO_2 molecule emitted began its journey underground, so the challenge is to put them back when we are done with them. Public perception and political sentiment are real, however, and need to be addressed before carbon sequestration is employed on a large scale. See Figure 13.

Technology is available and should be deployed to cost effectively reduce methane emissions

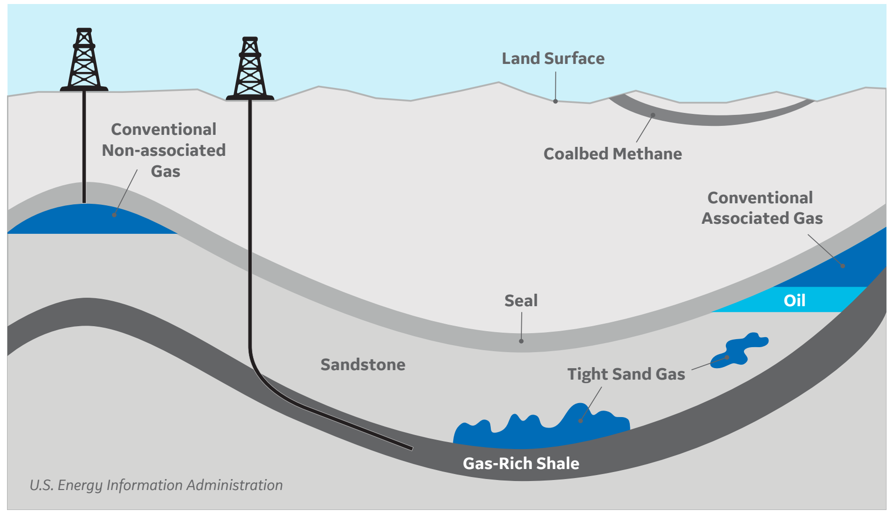


FIGURE 13: Geologic formations have stored gaseous natural gas, CO_2 and other hydrocarbons for hundreds of millions of years and may be feasible for safe and permanent CO_2 sequestration (image courtesy of the US Energy Information Administration).

METHANE EMISSIONS... AN OPPORTUNITY FOR REDUCTION

A concern often raised about natural gas power generation is that it is responsible for a significant increase in global methane (natural gas or CH4) emissions. Methane is 25X more potent as a greenhouse gas than CO_2 on a pound-for-pound basis. 570 million metric tons per year of methane are emitted globally, of which 40 percent are naturally occurring and 60 percent are anthropogenic. Methane accounts for 16 percent of anthropogenic greenhouse gases on a CO_2-equivalent basis, while CO_2 accounts for 76 percent. Twenty percent of total methane emissions are attributed to fossil fuels, of which coal is 25 percent, oil is 34 percent, and gas is 41 percent. Total oil and gas (O&G) related methane emissions are nearly 80 million metric tons per year, and are attributed to a combination of intentional venting, incomplete combustion of flared gas, and leaks in the production, processing and distribution of O&G. Natural gas-related methane emissions alone are 47 million metric tons per year, but only about 40 percent of global gas consumption is used in the power sector. **Gas power sector methane emissions, at 19 million metric tons per year,[33] therefore account for just 3 percent of total global methane emissions.**

The IEA estimates that O&G sector methane emissions can be reduced by nearly 75 percent by deploying available abatement technologies and practices. And about half of that reduction is possible with no incremental net cost (i.e., the value of the methane recovered is greater than the cost of the abatement technology.)[34] GE is supportive of policy that would require the power and O&G sectors to implement available methane abatement technologies and practices.

DIGITAL TECHNOLOGIES CAN TIE IT ALL TOGETHER

A key element of decarbonization of the power sector will be to ensure the entire system, including generating assets, the grid, and loads are integrated efficiently in order to optimize electricity generation and thereby minimize carbon emissions. This is where digital technologies can play an important role.

System operators will need to integrate and optimize dispatch of all assets after factoring in wind and solar resources days or weeks ahead, while considering the actual cost of each generation source including maintenance costs. Gas power plant component life is largely dictated by thermal consumption of parts, whereas wind components are driven more by mechanical wear, solar plants by output degradation, and battery systems on the number of charge/ discharge cycles. All these factors can be optimized digitally to ensure the lowest carbon/least cost generation solution is achieved in real- time.

Digital technologies can enable generation optimization to be coupled with grid optimization and a real-time understanding of demand to enable a system that works seamlessly across multiple generation sources, an intelligent grid, and varying demand, to maximize system efficiency, minimize CO_2 emissions, and ensure reliability.

POLICY: THE MISSING PIECE

GE supports the science and goals expressed in the Paris Agreement and the United Nations Framework Convention on Climate Change. The Paris Agreement was a landmark effort by 196 nations to agree to combat climate change and take actions and invest in a sustainable low carbon future. In alignment with the Paris Agreement, some states, municipalities, and utilities have also adopted zero-carbon or carbon-neutral pledges.

Cost reductions in renewables and advances in digital technologies are opening huge opportunities for energy transitions, while creating some new energy security dilemmas.

SOURCE: IEA WEO 2019

Meeting the targets of the Paris Agreement requires investment in new and upgraded technologies. Companies and innovators around the world are developing new technologies and solutions at an exciting pace. There is a range of decarbonization solutions that address the differences countries and regions experience in their energy needs. Governmental policies that define the objectives and foster innovation should help advance the goals of the Paris Agreement.

To achieve these goals, GE supports policies that:

- Measure and incentivize reductions in power sector carbon intensity (tons of CO_2 per MWh) with an emphasis on both near-term actions that drive the greatest reductions sooner, and a longer-term vision of ambitious carbon reductions leading to deep decarbonization in the coming decades.
- Are transparent and predictable, allowing lifecycle economics to drive investment decisions factoring in a cost of carbon in some form vs. generic mandates picking one technology over another.
- Establish market structures that value energy, flexibility and dependable capacity separately to encourage the optimum mix of technologies that are complementary in nature, provide energy security, and drive the greatest carbon reductions in an affordable and practical way.
- Reward R&D, innovation, and private risk taking.
- Encourage the free flow of goods and ideas consistent with the principles of the World Trade Organization.
- Reflect national and local circumstances.
- Set realistic timelines for reduction efforts with periodic reviews as knowledge of the science evolves and technology improves.

Policy reform is needed to establish a framework for making long-term power sector investments

GE has set its own goal to become carbon neutral in its facilities and operations by 2030. GE's goal focuses on its over 1,000 facilities across the globe, including factories, test sites, warehouses, and offices.

CONCLUSION & RECOMMENDATIONS

Addressing climate change must be an urgent global priority, requiring global action, national commitments, and consistent policy and regulatory frameworks.

Solving the climate change challenge requires cooperation across national boundaries, across sectors of the economy, and across the political spectrum. As stated by Fatih Birol, Executive Director of the International Energy Agency, it calls for a "grand coalition encompassing governments, investors, companies and everyone else who is committed to tackling climate change."

According to IHS Markit, "gas plants are highly reliable—able to fill in long gaps in renewable production in ways that today's energy storage technologies cannot—and flexible enough to ramp up and down quickly depending on the needs of the system, with the potential to run on low-carbon gas in the future. As the value of these characteristics grows over time, new gas plants could be an increasingly attractive option as a complement to intermittent renewables."[35]

Renewables and gas power have the capability to quickly make meaningful and long-lasting reductions to CO_2 emissions from the power sector. Neither will be as effective alone at decarbonization at the pace and scale needed to avoid raising average global temperatures by less than 2°C as outlined in the COP 21 Paris Agreement.

The power industry has a responsibility, and the technical capability, to take significant steps to quickly reduce greenhouse gas emissions. The solution for the power sector is not an either/or, renewables or natural gas proposition. It requires a multi-pronged approach to decarbonization with renewables and natural gas power at its core.

Recommended steps for the power industry include:

- Invest in a combination of wind, solar, batteries and gas-fired power at scale and with urgency
- As coal-fired generation declines, replace this capacity with renewables supported by gas power
- Advocate for policies that align with the goals of the Paris Agreement to reduce CO_2 emissions, while ensuring a safe, affordable and reliable electricity sector. Such policies should: 1) incentivize reductions in power sector carbon intensity with an emphasis on both near-term actions that drive the greatest reductions sooner, and a long-term vision of ambitious carbon reductions, 2) are transparent and predictable, and allow lifecycle economics to drive investment decisions, and 3) promote market structures that value energy, flexibility and dependable capacity separately in order to encourage the optimum mix of technologies
- Increase funding in Research and Development and incentive mechanisms to: 1) continue the cost decline and performance improvements in renewables, 2) develop renewables hybrid and storage technology, and 3) accelerate cost effective CCUS, hydrogen, small modular reactors, and other potential low or zero-carbon technologies for dependable capacity to complement renewables
- Advocate for producers and users of methane to employ the best available methane capture technology
- Encourage cross-sectoral cooperation for CO_2 emissions reductions such as providing green hydrogen produced from zero-carbon energy for use in the transportation sector

Addressing climate change will require government and consumer action. GE as a company is uniquely positioned to play a key role through its scale, breadth, and technological depth. We have been a key player in the power industry since its inception and have a suite of complementary technology including gas-fired power, onshore and offshore wind, hydro, small modular reactors, battery storage, hybrids and grid solutions needed for the energy transformation.

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FLEXIBLE GAS: AN ENABLER OF SOUTH AFRICA'S ENERGY TRANSITION

CONTENT

ABSTRACT

South Africa is currently experiencing a severe power crisis with the country plunged into daily black-outs (or ‘loadshedding’) largely due to a lack of new capacity coming online to replace the ageing coal fleet. As of late, announcements from the President have been made outlining a myriad of interventions to be undertaken to resolve the current crisis, many of which would support a significant growth in renewable energy onto the system.

This paper looks at both the adequacy of South Africa’s proposed energy crisis mitigation measures and the role that Gas Power plays in this context along with providing a view on how Gas Power can support South Africa’s energy transition to 100% renewables. Taking a completely transparent and participative approach to the power system modelling, we simulated the least cost power system up to 2032 under three scenarios, namely; “Perfect World” where the model has no restrictions on how to optimize the system; “Planned World” where we identify eighteen announced crisis mitigation measures (and IRP additions) that are successfully executed and; “Reality Check” where a view is taken on how such measures may be delayed, over-estimated, or not realised at all.

By comparing parameters including annual new-build capacity; unserved energy levels; reserve provider allocations; renewable penetration and curtailment; total system costs; and total system emissions; we can observe how far our planned mitigation measures are from the ideal world and what would happen if these measures don’t go according to plan. The results show that our Planned World is sufficient to alleviate the energy crisis but Reality Check will mean an exponential increase in the amount of load shedding we can anticipate.

Gas power is shown to play an important role in all three scenarios by providing dual dispatch functions we term “Flexible Peaking” and “System Contingency Reserves”. Under ideal conditions, preferably in the form of flexible Gas Engine power plants, provides combined energy and operational reserves which translate into capacity factors of 1-30% in ideal circumstances but which increases up to 60% under system contingency scenarios. The Perfect World, which requires the addition of 9 GW of flexible gas, 7 GW of energy storage systems, and 40 GW of combined wind and PV by 2032, enables a 26% ($26B) cumulative cost saving and a 17% cumulative emissions reduction when compared to the Reality Check. And when testing for a scenario where no new fossil fuel plants are built, we observe an unrealistically high battery new build requirement of at least 3 GW / 24 GWh per year; a 55% system cost premium; and a <1% emissions reductions being achieved when compared to Perfect World with new fossil fuels.

Recommendations are made, which are grounded in real life project examples, to implement distributed 100-400 MW Engine based power plants which will:

- Provide the much needed power to the grid with short construction times;
- Provide more localized reserve and flexibility advantages to key areas in the grid;
- Enable the realization of multiple new gas energy sources in South Africa; and
- Allow one to address key fuel supply risks using multi-fuel technologies.

INTRODUCTION

South Africa is currently faced with the immense challenge of addressing their immediate energy crisis in the context of meeting their emissions targets as a signatory of the Paris Agreement. And these challenges sit on the shoulders of an ageing coal fleet which today still produces >80% of the country's energy needs (Eskom, 2021). Eskom estimates that 6 GW of capacity is needed today to restore the power system however, with an estimated 1 GW of baseload coal likely to be removed through decommissioning and unavailability each year over the next 30 years, it is clear that significant capacity beyond the 6 GW will be required to ensure long term system stability (Colloquium, 2022). From the consumer's perspective, the country is currently experiencing up to level 6 load shedding[1)] and whilst Eskom predicts level 3 until the end of 2023, the risk of maintaining higher levels for the short term to medium term is a very real possibility (Eskom, 2022).

In fact, the situation has become so severe that the President himself made an exhaustive address outlining a number of initiatives that will be taken to try alleviate the crisis (South African Government, 2022). Some of these initiatives include:

- improving the coal fleet availability;
- fast tracking the implementation of upcoming renewable/gas/energy storage independent power producer programmes;
- removing the capacity size cap on private generation;
- entering into temporary Power Purchase Agreement's with existing generators;
- reducing license and Environmental Impact Assessment processing for renewable and transmission infrastructure; and
- increasing the international power imports.

It is clearly apparent that addressing the current crisis requires a multi-pronged solution at all levels of the energy value chain. For purposes of this paper, we limit our focus to currently identified new-build capacity initiatives ranging from rooftop PV to large-scale utility projects as fully described in Section 3 MODELLING APPROACH.

Gas-fired power generation ("Gas Power") is often featured as a key theme within discussions around energy security, a topic which as quoted by the Minister of Mineral Resources and Energy is "a priority for the government and our preoccupation as the Department of Mineral Resources and Energy" (Department of Mineral Resources and Energy, 2022). A market scan of over 15 expert opinions and studies related to the role of gas indicates that the majority views gas as a transitionary energy source in supporting South Africa's path to net-zero with a third of the opinions either indicating that "big gas"[2)] or no gas is needed for the South African system[3)] (see breakdown in Figure 1).

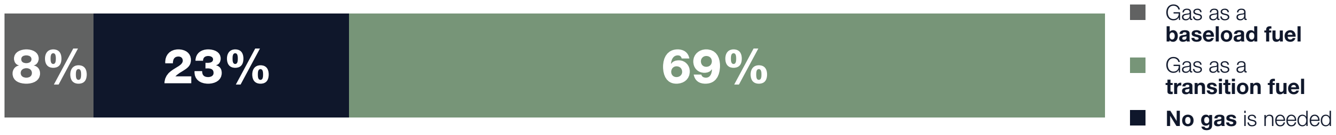


Figure 1: Poll on the role of gas for South Africa

[1)] Load shedding schedules go from level 1 (least worst) to level 8 (worst). Each level represents how many GW's is short in the grid which needs to be supplemented through cutting off consumers for a few hours at a time.

[2)] When referring to Big Gas, we take guidance from how it has been defined by Meridian Economics (Meridian Economics, 2022). It refers to gas-to-power plants that are operated at high capacity factors and utilize large gas volumes, for example, Combined Cycle Gas Turbines.

[3)] Sources for this survey includes Wits Business School; National Business Initiative; BUSA; Eskom; Eurasia Group; Shell; DMRE; Standard Bank; CSIR; Africa International Advisors; Amabhungane; Department of Mineral Resources and Energy; International Institute for Sustainable Development; Presendent Cyril Ramaphosa and Independent Analyst, Clyde Mallinson.

In this study, we attempt to draw comparisons with some of the analysis already done by credible organizations, namely, Meridian Economics in their study “Resolving the Power Crisis Part B: An Achievable Game Plan to end Load Shedding” and National Business Initiative (NBI) in their study “Climate Pathways and a Just Transition for South Africa: The role of gas in South Africa’s path to net-zero” (Meridian Economics, 2022) (National Business Initiative, 2022). Both have used sophisticated power system modelling software and well researched analysis to come to their conclusions but with slightly varying opinions on the role of Gas Power. Meridian proposes the immediate addition of 1.4 GW of peaking thermal (questioning whether gas should be considered instead of diesel due to the questionable economics to bring in LNG) and describes the role of gas as a “peaking and insurance provider”. They also show that in the case of the coal Energy Availability Factor (EAF) dropping by 2% per year, then the diesel fired peaking plant would experience up to 20% capacity factors up until 2026 (no further data beyond this date is provided). NBI states that “gas can, if affordably supplied, play a key role as a transition fuel to replace more emissions-intensive fossil fuels like coal and diesel, and provide flexible capacity to enable a rapid scale-up of renewables” (National Business Initiative, 2022). Their modelling shows that gas capacity factors of 10% on gas plants should be anticipated but with more mid-merit levels of 30% reached whilst the large coal-fired plants are decommissioned.

Both these studies provide valuable insights into the role of Gas Power but we believe that further analysis regarding exactly how gas plants would be used in the current context of South Africa is warranted.

For example:

- How will the capacity factor change in the event of an extended system contingency occurring?[4)]
- Does gas play a role in providing reserves to the system?
- Which gas technology is most suitable for South Africa’s needs and are the current plans for Gas Power sufficient to meet our energy crisis needs?

By understanding the power system requirements for Gas Power as our starting point, we can then start to look at how such projects may look like considering other factors such as gas supply options and grid location preferences. Addressing such questions would go a long way in aiding the thinking of future gas infrastructure developments which will have the maximum impact and least regret.

[4)] A system contingency could be any unplanned event which affects the systems supply/demand balance. In the context of this discussion, it is considered as more larger and longer term events such as an abnormal weather phenomenon; major transmission line failure; geo-political events which impact fuel prices; and a catastrophic failure of a coal plant.

OBJECTIVES

The objectives of this study are to:

1. Evaluate the adequacy of the currently planned energy crisis alleviation projects related to the addition of MW's onto the grid; and
2. Define the roles; technology; and envelope of operations that Gas Power should provide to the South African power system and discuss the associated benefits and risks associated with this along with presenting a conceptual solution.

MODELLING APPROACH

Model Overview

Power modelling software from Energy Exemplar called Plexos® was used for this analysis. Plexos® is a techno-economic modelling software that uses mathematically based optimisation techniques for energy market analysis, widely used by system operators, energy planning departments, and consultants.

A long-term capacity expansion optimisation approach was applied in this study. Capacity expansion modelling finds the least cost generation capacity mix for a power system to meet electricity demand in the future whilst respecting any given constraints. Plexos® selects new generation capacity additions from several potential technologies. Available options: solar, wind, battery storage (LiIon and Vanadium Redox batteries), Open Cycle Gas Turbines (OCGT), Combined Cycle Gas Turbines (CCGT), Internal Combustion Engines (ICE), nuclear, coal, hydro pump-storage, and technologies to produce synthetic fuels (P2H). Plexos® solves the hourly (2 hr in this case) dispatch of power plants throughout the studied period, which is years 2023-2032, whilst making new capacity additions that will enable the least cost energy for the system. By taking this chronological modelling approach, i.e., the variability and seasonality of renewable generation and load need to be balanced hour-by-hour in the model, and modelling the operational reserve requirements of the system, we can identify accurate flexibility and storage capacity requirements which would be overlooked in more conventional and overly simplified 'load duration curve' or 'merit order' modelling approaches.

Model Inputs

Like any model, the quality of the outputs is only as good as the quality of the inputs and for this reason, we adopted a transparent approach to the modelling which allowed other subject matter experts to provide their inputs and suggestions into our proposed set of inputs and assumptions. Our baseline data was derived from publicly available, and generally acknowledged to be reputable, sources as far as practicable. Any information that was not publicly available was provided by the Wärtsilä modelling experts based on their experience of similar models around the world.

To solicit inputs into our baseline inputs, Wärtsilä undertook a public participation process whereby key industry bodies and stakeholders were given the opportunity to comment on the input assumptions used in our model. Annexure A contains the Invitation Letter along with the respective list of all the key inputs and references that were used in the model. This invitation was distributed to approximately 6,000 energy sector stakeholders through various WhatsApp energy groups and email. Interested parties were then allowed one month to provide comments and attend a “introduction to modelling” webinar to have a better understanding of the modelling approach.

A total of seventeen people expressed an interest in the process however, zero changes to the inputs as put forward by Wärtsilä were volunteered (which was viewed as positive confirmation on the legitimacy and credibility of the proposed baseline modelling inputs).

Further to the exhaustive list provided in Annexure A, Annexure B contains a brief description on the approaches and assumptions we have taken on the key inputs.[5)]

Scenario Descriptions

In defining the scenarios, the objective was to test the role of gas under extreme circumstances that may be realized in the South African power system. These extreme cases, labelled as “Planned World” and “Reality Check”, enable us to gain insight into the operational envelope for Gas Power generation. As the name suggests, the Planned World scenario considers a system where all the recognized capacity addition measures are realized to their full potential and in line with their scheduled timeframes. The Reality Check scenario then takes a view on how each of those measures could either be delayed and/or reduced in capacity based on historical experience and/or anticipated behaviors’ going forward. These ‘unplanned’ events are what we refer to in this paper as system contingencies.

A third, and final, scenario, titled “Perfect World”, is one whereby we allow the model to determine the optimal capacity mix without imposing any of the known new capacity addition opportunities and/or restrictions. This Perfect World scenario allows us to benchmark our Planned World and Reality Check scenario in terms of achieving the lowest system tariff and reducing CO2 emissions.

Planned World	Considers a system where all the recognized capacity addition measures are realized to their full potential and in line with their scheduled timeframes.
Reality Check	Takes a view on how each of those measures could either be delayed and/or reduced in capacity based on historical experience and/or anticipated behaviors’ going forward.
Perfect World	Allow the model to determine the optimal capacity mix without imposing any of the known new capacity addition opportunities and/or restrictions.

5) It is well known that Plexos® has the capability to integrate a large amount of system variables however, based on our experience with system modelling, we have only listed here the inputs which we believe will have a material impact on the modelling results. Other inputs not listed here have either been integrated with ‘industry norms’ type of values.

A summary of the amount of MW's added for each initiative is summarized in the image below.

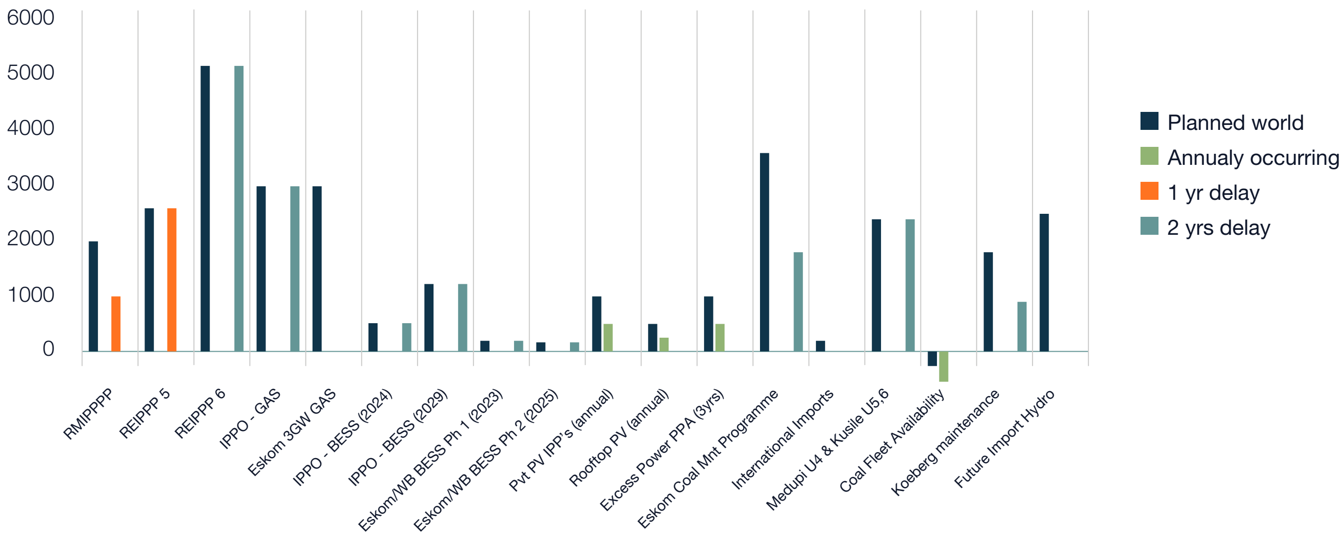


Figure 2: Treatment of how the impacted planned initiatives were either delayed or reduced in the Reality Check scenario

A more detailed description outlining the rationale for the delay and/or reduced MW's available under each initiative is provided in Annexure C.

In addition to the main scenarios as outlined above, further sensitivities to address related, and commonly discussed, topics have been undertaken which includes:

- Impact of not allowing for any new fossil fuel power plant to be built ("No Fossil Fuel");
- Impact of 'forcing' baseload CCGT's into the Planned and Reality Check scenarios[6] ("Big Gas"); and
- Looking at the role of gas should the gas price reflect a domestic supply being available ("Dom Gas").

[6] A concept often discussed is to replace/repurpose the current baseload coal fleet with baseload gas. We therefore impose a 70% minimum capacity factor for the CCGT's in this option and also reduce the gas price from $15/GJ to $12/GJ in recognition of the high volumes and stable offtake potential with this approach.

MODELLING RESULTS

New Capacity Additions

The table below adopts an 'IRP style' visualization comparing all three scenarios. The changes are based on the inputs and approaches as outlined in Annexure A and Annexure B with a full exhaustive list of associated installed capacity; new build capacity; and energy share graphs contained in Annexure D.

	COAL (MEDUPI/KUSILE ADDITIONS AND MAINTENANCE INCREASES)			AVAILABLE COAL CAPACITY (DECOMMISSIONING + REDUCED EAF)			NUCLEAR (+EXTENDED OUTAGE)			HYDRO AND PUMP STORAGE			BATTERY STORAGE		
	38773 (Eskom: 37149 + IPP: 1624)						1860			2100			2912		
	Planned	Perfect	Reality	Planned (1,5% EAF decline)	Perfect (no EAF decline)	Reality (3% EAF decline)	Planned	Perfect	Reality	Planned	Perfect	Reality	Planned	Perfect	Reality
2023	1600			-312		-633			-930				200	1652	
2024	800			-307		-614			-930				514	660	
2025	1800		1600	-3008	-2706	-3219							160	554	200
2026	1800		800	-315	-57	-553								589	514
2027			900	-252		-482								559	160
2028			900	-1643	-1394	-1759								886	
2029				-224		-415							1231	627	
2030				-221		-402				2500				465	
2031				-217		-390								464	1231
2032				-1803	-1589	-1762								621	
TOTAL NEW CAPACITY BY 2032 (MW)	6000	0	4200	-8301	-5746	-10228	0	0	0	2500	0	0	2105	7077	2105
TOTAL INSTALLED CAPACITY (% OF MW)	33,3	26,1	37				2,1	1,8	2,3	2,6	2	2,6	2,4	6,7	2,6
ANNUAL ENERGY CONTRIBUTION (% OF MW)	46,76	36,33	44,67				4,23	4,13	4,29	4,27	3,73	3,88	1,04	2,7	1,04

	PV (INCLUDES IPP'S + ROOFTOP)			WIND			CSP (INSTALLED BASE ALREADY INCLUDES CURRENT BUILD)			GAS & DIESEL			OTHER (RMIPPPP, P2H)		
	1474			1980			600			3830			499		
	Planned	Perfect	Reality	Planned	Perfect	Reality	Planned	Perfect	Reality	Planned	Perfect	Reality	Planned	Perfect	Reality
2023	500	2700	250		2502						850			150	
2024	500	1098	250		2562						11		1995		
2025	2500	1123	750	1600	2621						3235				1000
2026	3500	1149	750	3200	2681					3000	160				
2027	1500	1175	1750	1600	2741	1600					15				
2028	1500	1200	2750	1600	2801	3200				3000	1642	3000			
2029	1500	1226	1750	1600	2861	1600					224			262	
2030	1500	1252	1750	1600	2921	1600					251			726	
2031	500	1277	1750	1600	2981	1600					249			434	
2032	500	1303	1750	1600	3040	1600					2308				
TOTAL NEW CAPACITY BY 2032 (MW)	14000	13503	13500	14400	27711	11200	0	0	0	6000	8945	3000	1995	1572	1000
TOTAL INSTALLED CAPACITY (% OF MW)	18,3	13,6	19,7	20,2	30	18,4	0,7	0,6	0,8	10,3	12,6	7,7	2,3	1,4	1,3
ANNUAL ENERGY CONTRIBUTION (% OF MW)	13,2	11,28	13	17,23	33,25	15,4	0,71	0,69	0,72	2,02	3	8,63	4,34	<0	2,2

Table 1: IRP styled new build and energy share overview for each scenario

Coal

The addition of the Kusile Units 5 and 6 and the repair to Medupi Unit 4 would provide a significant amount of energy to the system along with the increased capacity that is claimed to be possible through increased maintenance (deRuyter E. -A., 2022). It was questioned whether these additions should be committed into the Perfect World as there is already a significant sunk cost into these projects but arguably, in a perfect world, there could be scope to divert those funds to other projects. In which case, we see that no new coal is built in the Perfect World nor any capex is spent to improve the performance of the current fleet.[7)]

Observing the effective lost coal capacity through decommissioning and reduced EAF, in Reality Check, which has a 3% annual EAF reduction, we see that over 10 GW is lost within 9 years. And the picture is only slightly improved in the Planned world where 8.3 GW is lost over 9 years.

The total energy share of coal by 2032 is 36% in the Perfect World (which is a significant drop from our current 80% level!).

[7)] It was assumed that the cost for existing plant performance improvements would be the equivalent to a new build capex cost. This however should be investigated further.

Nuclear

No new nuclear is recommended largely due to the high capital costs considered.

Hydro and Pump Storage

Apart from the 2.5 GW hydro that already exists in the current IRP (and which is premised on the realisation of a regional hydro project), no new hydro nor pump-storage is built.

Storage

There is 5 GW more storage proposed in the Perfect World than the current Planned and Reality Check scenarios. 2 GW of which is immediately required followed by an annual, and steadily increasing, contribution to align with the growth in renewables. Whilst both LiIon and flow batteries were modelled, only LiIon batteries were selected but it should be noted that this preference is highly susceptible to the technology learning rates and should not be taken as a firm view that LiIon is better than alternate emerging battery technologies.

The model opts to build predominantly 1hr and 2hr batteries in the first 2 years thereafter, it builds predominantly 4hr batteries until 2031 wherein some 8hr batteries are then built.

Solar PV, Wind, and Concentrated Solar Power

Solar PV (Photovoltaic) and Wind is built at huge scale up to the imposed limit in the model which was taken to be 10% of the peak demand[8)] (with a preference give to Wind as the cheaper renewable technology option). Collectively, their energy contribution in the Perfect World is 45% in 2032. No new Concentrated Solar Power is built.

Gas & Diesel

In terms of converting the existing diesel fired OCGT's to gas, we only see this conversion taking place in the Reality Check across the years 2023 to 2026. No conversions are suggested in both the Perfect World and the Planned World as the capacity factors are just too low to warrant such a conversion.

In terms of new build gas capacity, here we see a significant increase in the MW's required from 3 GW in Reality Check to 9 GW in Perfect World. Most of the additions are within the 100-300 MW range with the exception of a few larger 'chunks' which get addition at the same time that there is coal plant being decommissioned. And even though they make up over 12% of the installed base, there is a much smaller energy share contribution of 3% in the Perfect World. This is not the case though in Reality Check where they are only 8% of the installed capacity by 9% of the energy share.

Other

'Other' in the IRP2019 (Department of Mineral Resources and Energy, 2019) contains an annual build of 500 MW however, we took that view that it is more likely that other would be dominated by private+rooftop solar which already falls under the 'PV' category in the model. The only 'Other' consideration we have then is the projects under the RMIPPP and P2H projects. P2H only appears after 2029 in the Perfect World.

[8)] Whilst it must be acknowledged that there is some practical limit as to how much renewable energy can be built on an annual basis, what that limit is not easy to determine as it is impacted by many unknown factors. We, however, have used a value of 10% of the peak demand as this is what Wartsila has experienced in other jurisdictions and in our view represents a fair but achievable annual new build limit.

‘No Fossil Fuels’ sensitivity

In the sensitivity where we don’t allow for any new fossil fuel power plant to be built, the model opts to build batteries with a small portion of CSP in 2028 and a 1.7 GW nuclear power plant in 2032 (note: a 10 year new build time for Nuclear has been considered). Whenever there is a drop in coal through decommissioning, this capacity is replaced with GW’s of 8hr duration batteries with the installed battery capacity amounting to 27 GW / 216 GWh by 2032, which is 20 GW more than the Perfect World scenario! This means, that on average, South Africa should be building 3 GW / 24 GWh of batteries every year, a target we do not believe is realistically viable given the global supply capacity limitations and competition from more mature competing markets. The graph below indicates the new built technologies in the absence of fossil fuels.

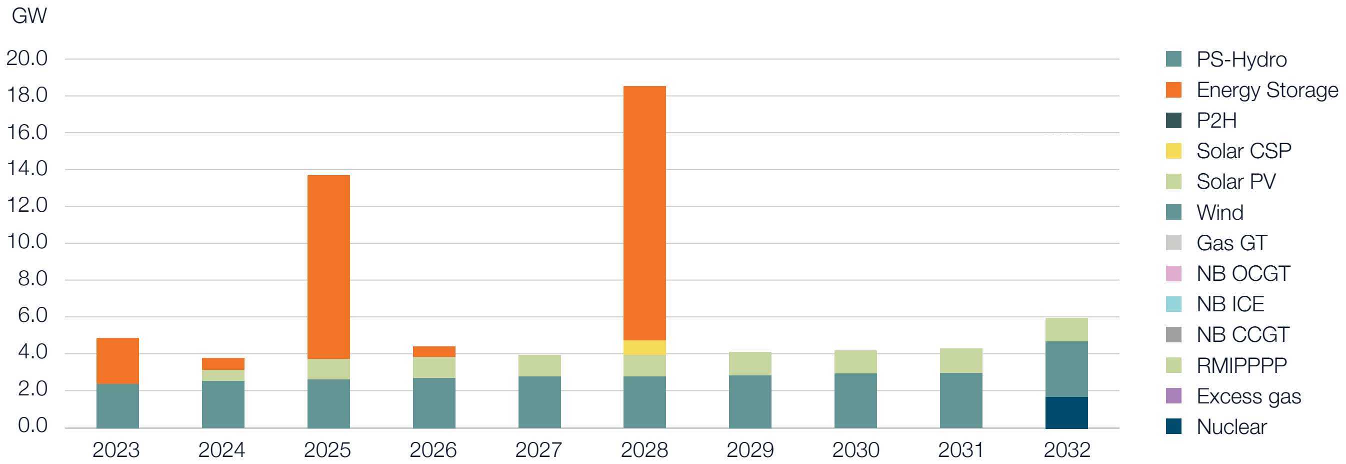


Figure 3: New build capacities when no fossil fuels are allowed to be built in the Perfect World.

Key Gas Power Observations

Gas Technologies

Despite the model automatically having the option to select between CCGT’s; OCGT’s; and ICE technologies, the preferred technology to support a least cost system is the ICE option which makes up >95% of all the new build gas across all three scenarios.

The model selects engines as the least cost Gas Power technology primarily due to its ability to provide flexibility at low cost to the power system. This is achieved through the following key characteristics:

- High efficiency is available at all plant dispatch levels
- No costs incurred for starting up[9)]
- Low capex
- Able to provide non-spinning operational reserves due to the fast ramp-up rates

On the other hand, CCGT’s only make a small appearance with 670 MW in Perfect World in 2025 and 280 MW in 2028 when there is a temporary raised capacity factor required due to coal being decommissioned in those years.

9) Unlike gas turbines, engine (ICE) technology does not incur any additional start-up cost nor require additional starting fuel (Wartsila, 2022). Furthermore, the fact that there is no limitation on the number of starts means that the model can rely on engines for a large portion of its flexibility requirements without adding significant costs.

Gas Dispatch Requirements

In this section, we explore in more detail how Gas Power is used in the power system under the varying scenarios. What will become abundantly clear through these results is that it is not sufficient to merely label gas as 'peaking' or 'mid-merit' as this overly-simplifies what in reality is far broader and more dynamic.

Gas power players a significant role as both an energy provider and an operational reserves provider to the system.[10] And depending on the scenario considered, the requirement for each function varies.

Energy Provider

If we look at the energy provider function, we notice that the energy capacity factor for Planned World and Perfect World are similar with annual capacity factor ranges of 3-12% (which aligns well with the NBI and Meridian studies views). This picture however changes significantly in the Reality Check scenario where gas starts from 36% in 2028 (i.e. when the first Gas Power is commissioned) and increases to 58% in 2032. This is primarily due to the rapid decrease in coal capacity and availability.

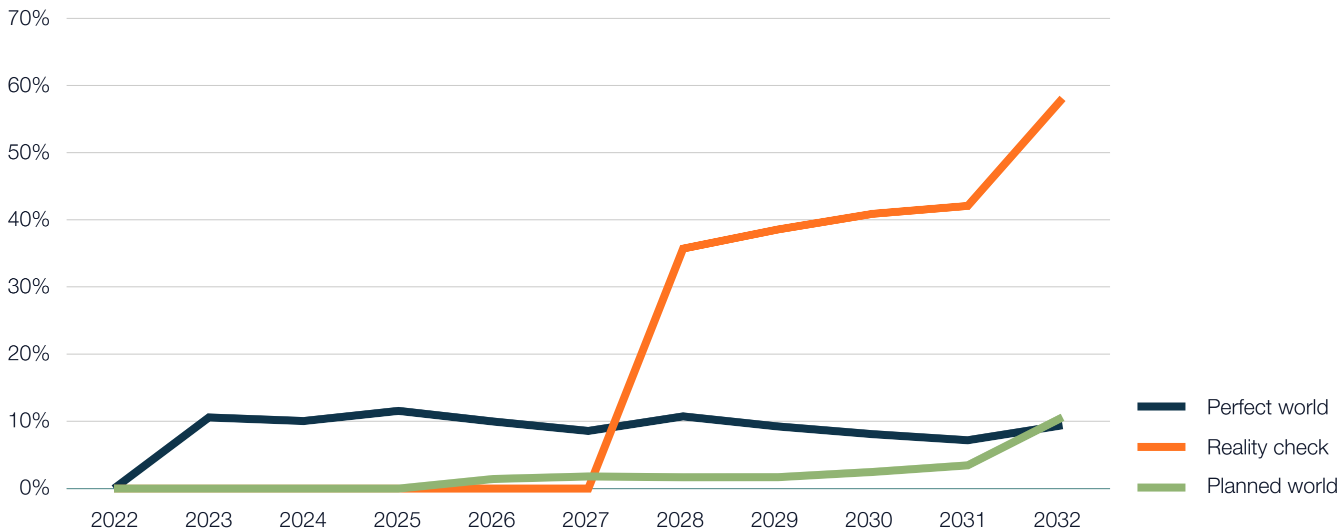


Figure 4: Gas Power Energy Capacity Factors per year fo each scenario

[10] If a technology provides energy to the system, that means that is required to generate power according to the day/week/month/year ahead energy dispatch forecasts. If a technology is a reserves provider, it only requires the technology to be available to provide energy to the system in the event that there is a supply/demand mismatch or frequency deviation on the grid (as defined in the Grid Code).

When looking at the intra-annual dispatch patterns of these gas plants, it is apparent that there are large variations in capacity factors at hourly; daily; weekly; monthly; and seasonal timeframe. At the hourly and daily level, the "Peaking" application as seen under Perfect and Planned Worlds exhibits peaks of varying sizes sometimes occurring twice a day or even no times for a few days. Similarly, the Reality Check dispatch sometimes has baseload characteristics and peaking characteristics within a single week.

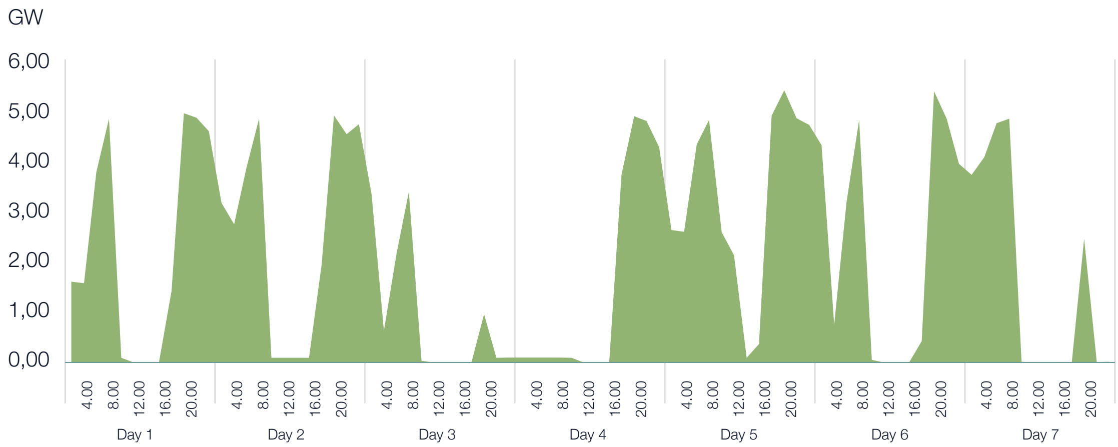


Figure 5: Typical weekly Gas Power dispatch profile for 2032 in the Planned World.

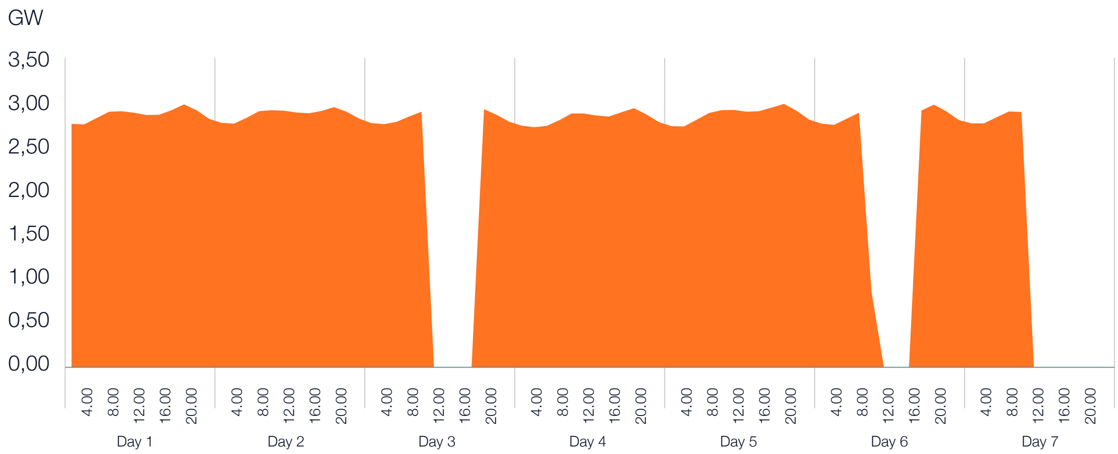


Figure 6: Typical weekly Gas Power dispatch profile for 2032 in the Reality Check.

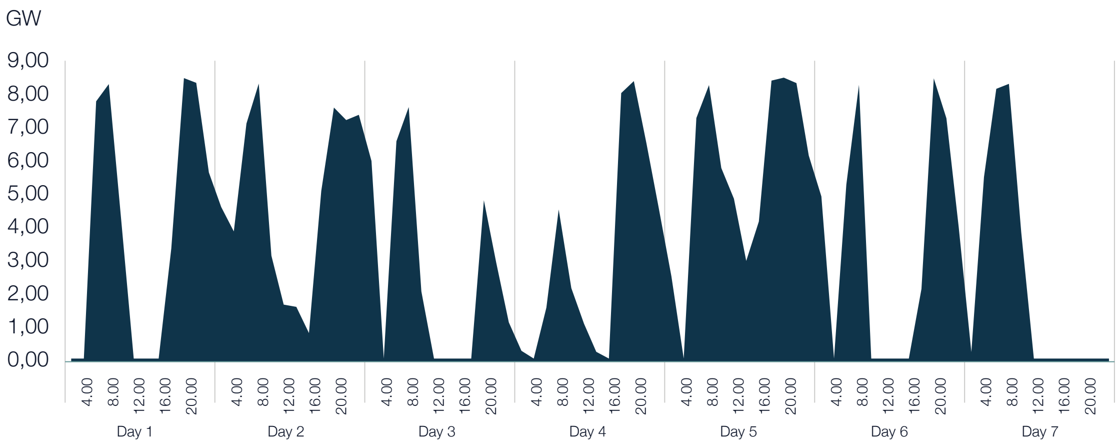


Figure 7: Typical weekly Gas Power dispatch profile for 2032 in the Perfect World.

At the weekly and monthly level, there is significant weekly variation in the energy dispatch with jumps of up to 30% capacity factor between consecutive weeks experienced for the Perfect and Planned World and 50% for the Reality Check with a peak weekly capacity factor of 89% being reached! This is largely due to the provision of both a traditional peaking application along with providing a renewable energy balancing function. Lastly, at the monthly and seasonal level, we notice a clear increase in the dispatch over the Winter months vs the summer months where anything from 40-54% of the total Gas Power is produced during May through August.[11)]

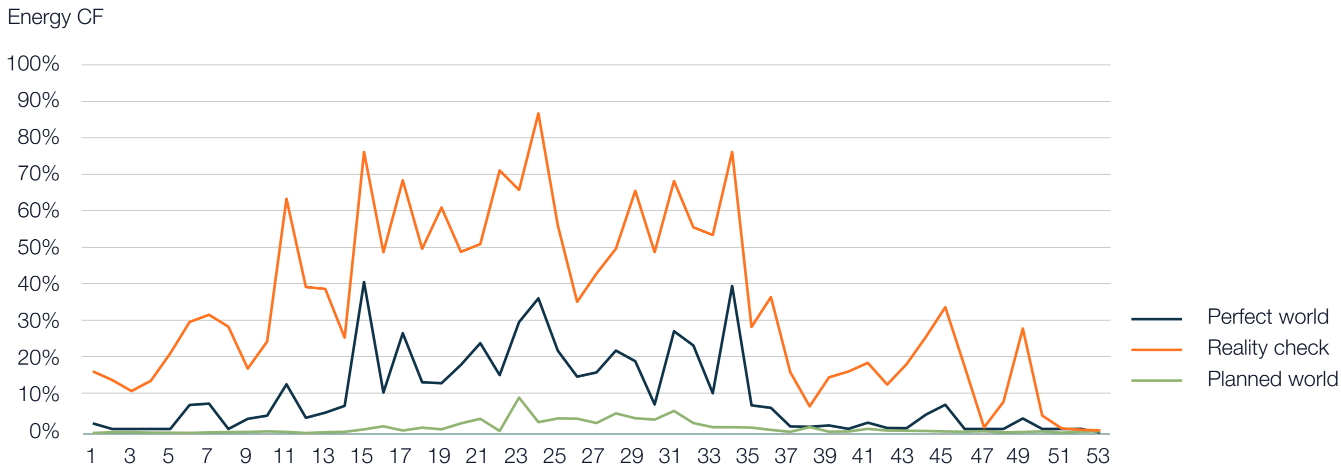


Figure 8: Weekly capacity factors for Gas Power in 2028.

Taking the observations around variability one step further, we also highlight the daily and annual gas consumption encountered for each scenario as depicted in the Figure 8. Naturally, the variability follows that of the Gas Power variability but in terms of total consumed gas, a summary of the gas consumption for 2028 is provided in Table 2.

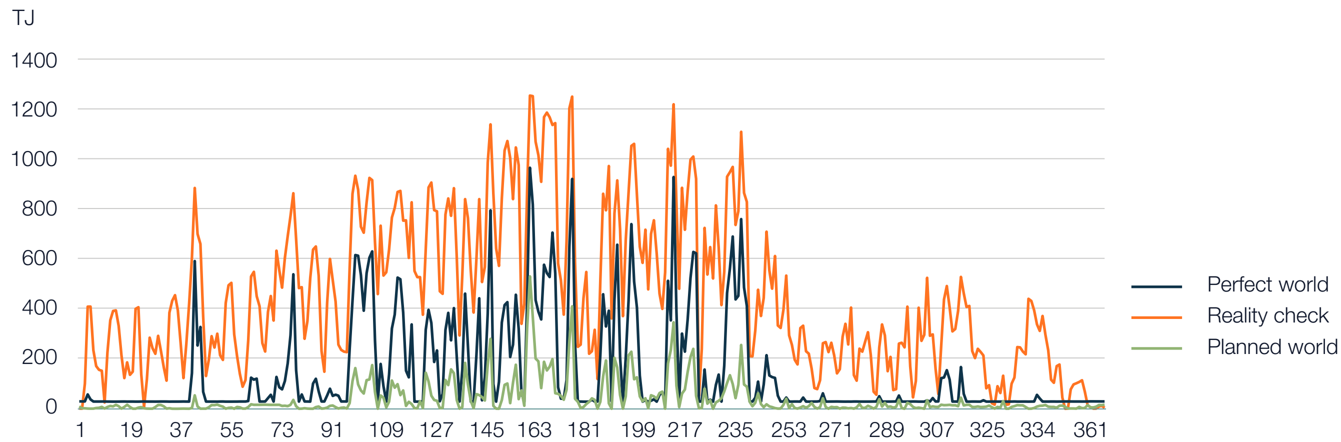


Figure 9: Daily gas consumption profiles for each scenario in 2028

	Perfect World	**Planned World**	**Reality Check**
Installed Gas MW's in 2028	**8 GW**	**6 GW**	**3 GW**
Annual Gas Consumption[12)]	**53 PJ**	**15 PJ**	**167 PJ**

Table 2: Summary of total gas capacity and gas consumption in 2028.

[11)] It is recognized that through shifting of the coal fleet maintenance into the summer months, this seasonal imbalance in Gas Power demand could be improved (or flattened). Our approach in this model was to assume that 7% of the planned maintenance for the coal fleet could be shifted towards the Summer months.

[12)] Note that these values do not include the consumption from the RMIPPP gas projects as it is assumed that these projects do not have an 'open access' possibility. It also does not include the gas that would be required for providing operating reserves to the system but it does include the gas consumed in the converted existing OCGT's.

Reserves Provider

We now focus the discussion on Gas Power as a reserves provider where we see each scenario taking a slightly varying view on who the reserve providers are for the system.

In the Perfect World, we see that all the system reserves are supplied through a combination of BESS (15-20%); Diesel OCGT (23%-37%); and ICE (41%-63%). This outcome resonates well as BESS is ideal to provide the instantaneous and regulating reserve support whereas the current diesel OCGT's and new gas ICE is able to provide cost effective non-spinning reserves to contribute to the regulating and 10-min reserve requirements of the system.

This balance changes slightly in the Planned World whereby we still see coal (which has traditionally been the main reserve provider to the system) providing some reserves to the system (10%-23%); BESS and ICE making their contributions but diesel OCGT still providing the majority of reserves (25%-50%).

Lastly, in the Reality Check world, there is a significant deficit in the available reserves and as a result, the model relies on 'load shedding' to provide system reserves in addition to BESS; diesel OCGT's; gas converted OCGT's; and new build ICE when it comes available. The respective share of the reserve providers for each scenario is shown in Figure 10, Figure 11, and Figure 12.

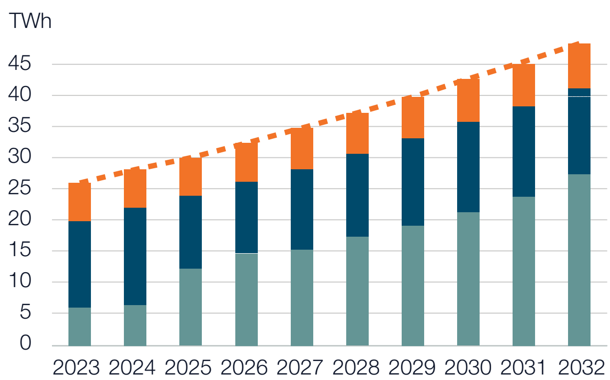


Figure 10: Share of reserve providers in the Perfect World

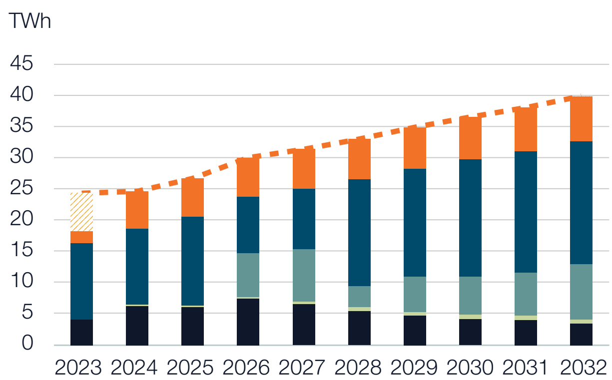


Figure 11: Share of reserve providers in the Planned World.

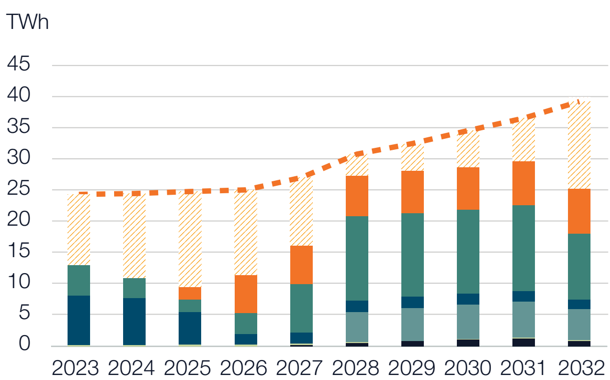
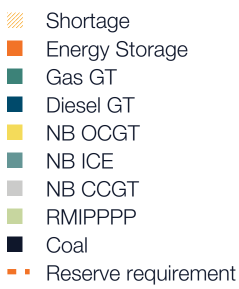


Figure 12: Share of reserve providers in Reality Check.



Focusing on Gas Power reserve provisions, in the Perfect and Planned Worlds, Gas Power as a reserve provider trumps that of its energy supply function with reserve capacities of 10-50% being assigned to this function. The reverse is true in the Reality Check scenario whereby there is more energy provisions allocation from the ICE capacity than reserve provisions allocation which ranges from 20-30% of the gas capacity. The system however does continue to rely on the converted OCGT's to play a significant role in providing reserves to the system.

When looking at the type of reserves that each technology contributes to, considering the Perfect World, the approximate ratio is that spinning reserves is made up of 50% from BESS and 50% from ICE whereas non-spinning reserves is made from 40% ICE and 60% OCGT.

What is abundantly clear from these results is that Gas Power has an equally significant role to play as both an energy and a reserves provider and that the traditional approach of assigning a small portion of the plant capacity to provide reserves (as seen in the current coal fleet) would be a gross underutilization of the flexibility advantages Gas Power can provide to the system.

Gas Price Sensitivity

All the simulations undertaken have considered a gas price of \$15 / GJ (see section 3.c). Additional simulations considering \$10 / GJ and \$6 / GJ were then modelled and virtually no difference in both the Gas Power capacity installed and the Gas Power capacity factor observed. The same outcome will be true for higher gas prices until the gas price exceeds the diesel cost which has been set at \$20 / GJ (as concurred by NBI's findings (National Business Initiative, 2022)). And even if today we are seeing >\$20 / GJ LNG pricing, as there is some correlation between diesel and LNG pricing indices, it is unlikely that LNG would ever exceed a diesel supply cost (CME Group, 2022).

This demonstrates that Gas Power is relatively insensitive to gas price as it exists within a wide merit order price window (for dispatchable capacity) between coal and diesel OCGT's.

If, however, we wish to explore the opportunities should a low cost domestic supply of gas is available, considering a gas price of \$3 / GJ, it is likely that we will see a significantly different role of gas as more a mid-merit/baseload energy provider to the system. At this price, the following gas technologies and capacity factors appear:

- Perfect World: 5.4 GW of ICE with 20-30% capacity factors and 4.9 GW CCGT with 80% capacity factor;
- Planned World: 5.1 GW of ICE with 30-40% capacity factors and 800 MW of CCGT with 70-80% capacity factors
- Reality Check: 3 GW of ICE with 60-70% capacity factors.

It is interesting to note that when comparing the original Perfect World scenario to the Domestic Gas Perfect World scenario, there is virtually no difference in the total installed gas capacity, only that capacity factors increase.

In order to achieve such a low domestic gas price, we believe that South Africa must undergo a radical gas revolution similar to what was experienced in the US through the discovery of shale gas which created a <\$3 / GJ market.

Other Key Observations

System Costs

Unsurprisingly, given that the model optimizes for the least cost of energy, the Perfect World presents the lowest cost to the consumer with Planned World and Reality Check scenarios exhibiting 13% and 26% higher costs respectively when comparing the cumulative costs up to 2032. The cumulative difference between the Perfect World and Reality Check is $26B up until 2032.

Figure 13 shows the annual system costs for each scenario.

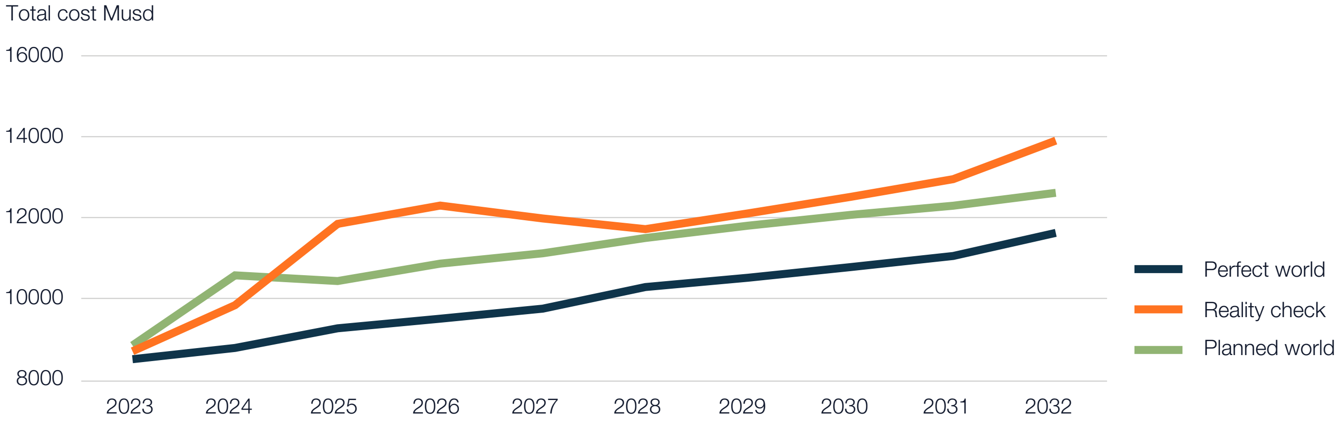


Figure 13: Annual power system cost for each scenario

If we also extend our system cost observations for the No Fossil Fuel and Big Gas sensitivities, the results clearly indicate a material cost premium associated with these two sensitivities when compared all three original Perfect World; Planned World; and Reality Check scenarios (refer to Table 3). The Big Gas sensitivities carry an approximate 20% premium, despite the lower gas price of $12 / GJ considered achievable with a high stable offtake, and the No Fossil Fuels has an approximate 55% premium largely due to the large capital outlay required for the significant battery additions and Nuclear addition.

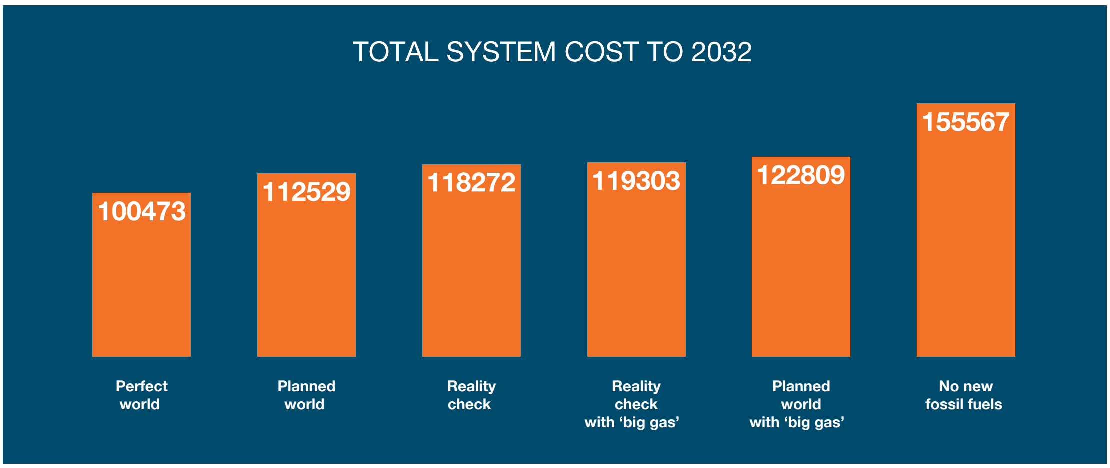


Table 3: Total System costs for the baseline scenarios; Big Gas; and No Fossil Fuels scenarios and sensitivities

Unserved Energy

By extracting the unserved energy parameter (or "load shedding"), we not only determine the relative accuracy of our model but also the risk of not meeting the Planned World objectives which is to eliminate load shedding.

In the Planned World, we don't see any significant load shedding appearing largely due to the timeous addition of the Medupi and Kusile coal units and the coming online and the RMIPPPP projects. The picture, however, does not look promising in the Reality Check scenario whereby there is already 0.4 TWh of load shedding in 2023 which triples in 2024; increases five fold by 2025 and ten fold by 2026 as shown in Figure 14.

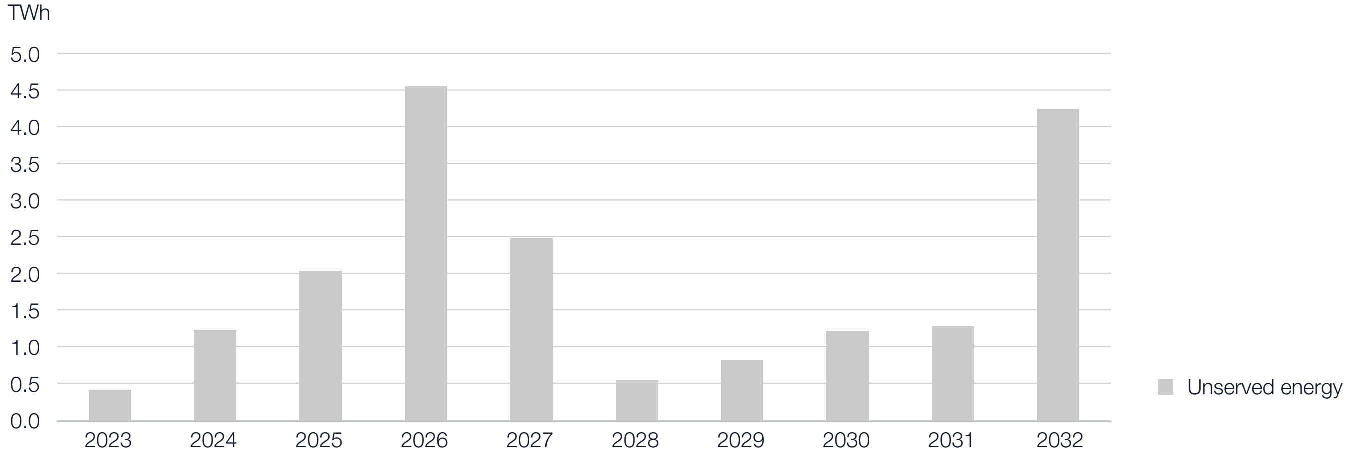


Figure 14: Annual amount of unserved energy in the Reality Check scenario.

When comparing to the latest load shedding statistics, considering that the amount of load shedding in 2022 up until June is 2.2 TWh, if we conservatively assume it continues unchanged for the remainder of the year, it means that our model would have under-estimated the load shedding by a factor of ten. Whilst there is a material difference between reality and the model in this regard, it must be stressed that the amount of load shedding is extremely sensitive to all the parameters and there will inevitably be some 'reality' inputs that are not practical to model.[13)] This result is also not unique for this model as when comparing to Eskom's predictions of unserved energy in 2022, the 'worst case scenario' predicts only 0.45 TWh which is very closely aligned with our current modelling predictions (Eskom, 2022).

Despite the difference in the starting point, the exponential increasing trend up to 2026 and the persistence thereafter in the Reality Check means that the continued roll-out of the Planned Initiatives (and new initiatives) needs to be considered as soon as possible. It can also be argued that with such high levels of load shedding, that the country growth, and subsequently energy demand, could be arrested thus artificially decreasing the amount of load shedding the country will experience.[14)]

One area which should also be recognized is that this study only looks at load shedding caused by a lack of generation capacity however, as most of the country relies on aged transmission and distribution infrastructure, there has been, and will likely be, a marked increase in the rate of failure at both transmission and distribution levels resulting in further effective load shedding.

[13)] For example, the unexpected outage of a single 600 MW coal unit for a few months could easily account for this difference between the model and reality.

[14)] In a media statement released by BUSA on the Eskom load shedding, they claim that the 0.7% decline in the economy during the 2022 second quarter was caused by the continued blackouts (Business Unity South Africa, 2022)

Emissions

Contrary to what would be expected, the Reality Check scenario, despite its lack of new build capacity, actually results in the largest amount of CO2 emissions compared to Perfect and Planned Worlds. This is primarily due to the continued reliance on coal and diesel to balance the system which both have higher emission factors than Gas Power.[15)]

The Planned World closely follows the emissions reduction trajectory of Perfect World up until 2027 whereafter it plateaus due to the continued reliance on coal and diesel in the absence of any new gas power. Even though the Perfect World continues to add Gas Power up until 2032, and the Planned World has no thermal (in the form of gas; coal; or diesel) additions beyond 2028, the cumulative emissions is lowest in the Perfect World by 7% compared to the Planned World. Reasons for this is that Gas Power, combined with the increased renewable energy, is able to displace more coal and diesel energy and therefore result in a significant net emissions reduction of 300 Mt (or 17%) when comparing Perfect World and Reality Check scenarios.

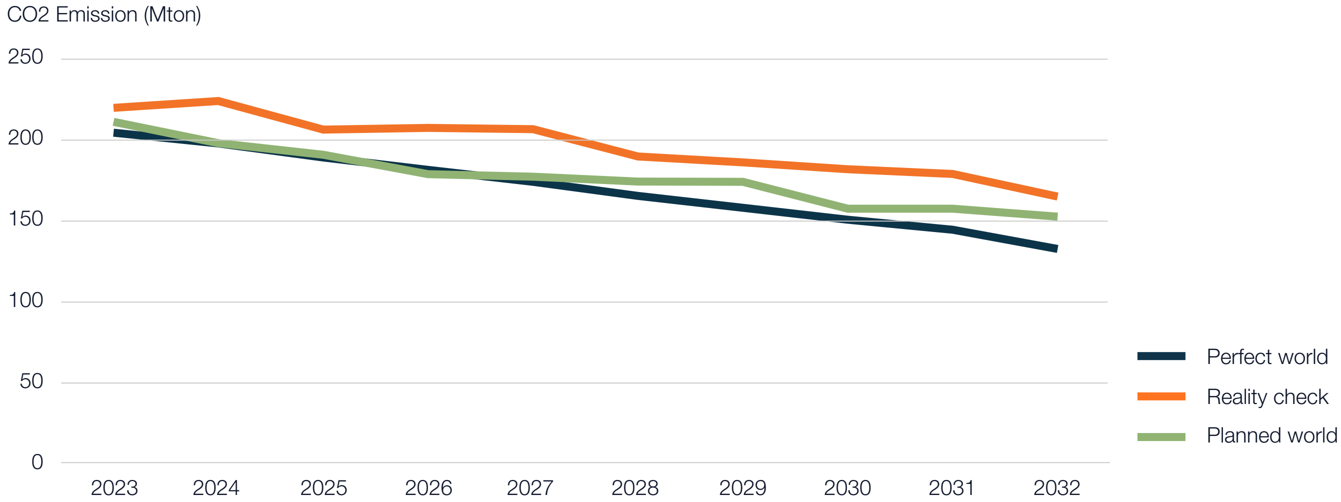


Figure 15: Annual CO2 emission trajectories for each scenario.

An encouraging outcome is that without imposing or forcing any specific emission reduction targets or constraints, the Perfect World naturally results in a trajectory which if continued to 2050, would enable South Africa to reach their net-zero targets.

Extending our emissions observations to include the No Fossil Fuel sensitivity, when comparing the baseline Planned; Perfect; and Reality Check Scenarios and the No Fossil Fuel versions, there is less than 1% decrease in system emissions achieved by not building new fossil fuel plants. This is largely due to the fact that we will continue to heavily rely on our existing coal and diesel fleet to provide such flexibility (in addition to the large amount of batteries added to the system) which has an emissions premium associated with it thereby offsetting any increases that would be realized through new, predominantly gas fired, power plants.

[15)] The following emission factors have been used in the model: Coal – 96.1kg/GJ; Diesel – 63.1kg/GJ; and LNG – 56.1kg/GJ.

Enabling Renewables

Between the three scenarios, we see a material difference in how renewables (wind and solar) is supported in the system by observing the amount of curtailment and penetration as depicted in Figure 16 below.

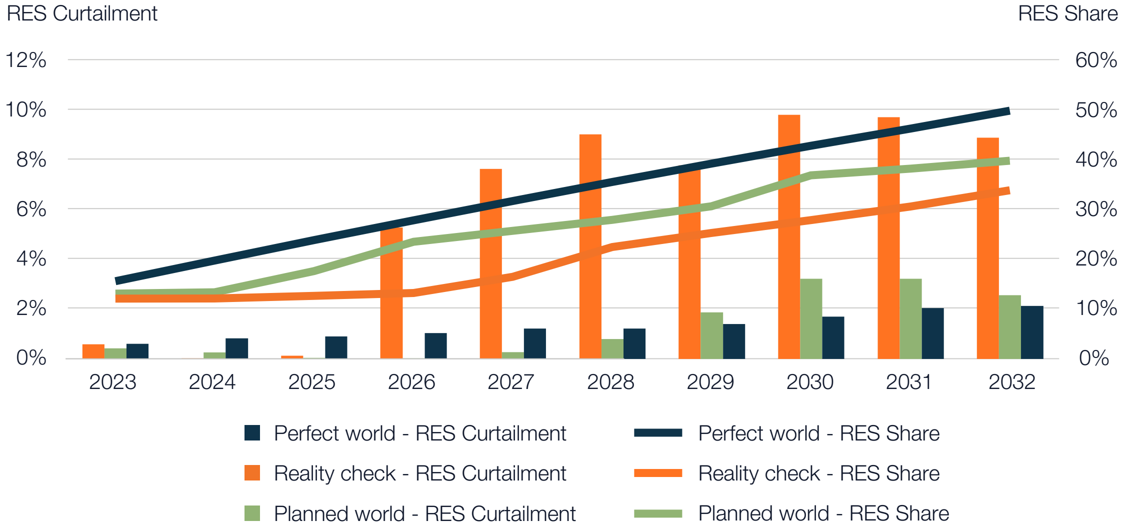


Figure 16: Annual renewable energy share and curtailment levels for each scenario.

Comparing the Perfect and Planned World, despite there being ~40-50% more renewable penetration in the Perfect World, there is never more than 2% curtailment whereas Planned world goes up to 10% curtailment in 2032. The Reality Check however, does not experience as much curtailment as the penetration of renewables is significantly lower than the Perfect World case.

This dramatic difference between the Perfect World and the Planned World highlights the importance of having not only a sufficient amount of flexibility but also the right 'mix' of flexible generators in order for renewables to reach their full potential.

For example, having the 8 GW of flexible gas in the Perfect World in 2028 versus only having 6 GW in the Planned World means that there is an increase of 6.7% renewable curtailment due to the lack of flexibility available in the system.

Power-to-Hydrogen

Power-to-Hydrogen (P2H) makes an appearance in the Perfect World through the addition of ~1.4 GW between 2029 and 2032 and is primarily used for energy balancing during the Winter months (very low load factors). During the modelling process, it was found that the inclusion of P2H was highly susceptible to the competing capex price of energy storage (8hr) which indicates that recognition for this technology is largely dependent on the long term capex reduction forecasts for electrolyzers and energy storage in form of batteries.

An additional variable which would have a material impact on the feasibility of P2H is that of Hydrogen storage technology (not included in the model). Considering that P2H is largely used to provide energy during the winter months, H2 would require significant storage capacity to allow for H2 production year round but consumption for only a portion of the year. There are a number of ways in which H2 can be stored such as the construction of conventional cooled H2 tanks or even storing H2 in unused mines. For purposes of this study, due to the lack of information available on this, storage has not been considered.

Despite the uncertainty around long term predictions for P2H, we do believe it potentially could play a role in the future (i.e. >2029) energy mix especially considering that any new build Gas Power has a 20-30 year lifespan meaning that at some point, there will likely be business case for blending of H2 into the gas supply mix.[16)] It should also be noted that when referring to Hydrogen as a possible fuel source for power generation, it would also encompass other Hydrogen based options such as Ammonia and Methanol as these fuels are more suitable for ICE technology.[17)]

[16)] This must be subject as well to the technical limitations associated with each technology. Today, ICE can blend up to 25% of H2 in their gas engines but research and developments in this area is ongoing (Wartsila, 2022).

[17)] In fact, Methanol ICE is already a commercial available product for the marine industry and Ammonia as a fuel source for ICE is at an advanced stage of development also for the marine sector (Wartsila, 2022) (Wartsila, 2022).

DISCUSSION

The Roles of Gas Power

As shown from the modelling results, it would be misleading to restrict the defined role of Gas Power to a single dispatch pattern such as peaking or mid-merit due to its wide range of anticipated energy and reserve capacity factors. And whilst the study undertaken by Meridian does principally identify this range by stating that gas provides peaking and insurance functionality, this description entices one perceives that it would operate in a peaking mode except for the rare occasion of backing up the system if required (like one would claim from your car insurance). However, the reality is that Gas Power is likely to play a far more significant role in building resilience into the power system by acting as the 'power safety net' in any system contingency event which can (and will likely) happen. In this study, we have identified eighteen possible system contingencies, but the reality is that there are many more factors that may result in the need for Gas Power to step in and maintain system stability. And the chances of all South Africa's planned energy crisis mitigation measures been undertaken successfully is arguably very low given the historical performance of many of these initiatives. As a result, one can very much anticipate a world whereby Gas Power operates at above peaking capacity factors for extended periods of time (5 years+) until South Africa can achieve their 'ideal' power system mix. And when we do reach this 'ideal' state, a pure peaking function would be more aptly described as a 'flexible peaking' function as there is a degree of renewable balancing and conventional peaking functionality as reflected by the 10-30% energy+reserves capacity factor ranges.[18)]

In summary, we believe that a more accurate description for Gas Power would be as a provider of 'System Contingency Reserves' and 'Flexible Peaking' capacity.

Based on this new dispatch definition for Gas Power, we can then appreciate that the amount of Gas Power required would be significant and according to our analysis, new gas capacity roughly matches the amount of effective coal capacity going offline every year which is ~1 GW per year. And preferably, this capacity should be serviced by ultra-flexible engine technology in order to provide the best optimisation capability for the maximum contribution from renewable energy (i.e. reduced curtailment and maximum renewable penetration).

The engine technology is a least regret option to select as it clearly dominated the new build preferences under all scenarios and gas price sensitivities.

[18)] The ideal state requires approximately 10% of energy capacity from gas and an additional 30-50% of operational reserves capacity. If we estimate a 50% dispatch level on the operational reserves, the net effective Gas Power capacity factor is in the order of 10-30%.

Gas Supply

When it comes to the supply of gas to a 'Flexible Peaking + System Contingency Reserve' Gas Power plant, it is worthwhile to reflect on some of the implications of requiring such flexibility into the entire gas supply chain.

When looking at the total annual gas requirements for each of our scenarios, we see anything from 15 PJpa to 167 PJpa being required over the coming years. In context of the LNG supply world, these numbers may be percieved to be relatively low as a typical FSRU could supply as much as 200 PJpa. And in context of how much South Africa currently consumes, it represents 12-76% of what is currently supplied through the ROMPCO line from Mozambique (Old Mutual, 2022). These numbers do present some challenges should there be an intention to 'anchor' LNG imports through Gas Power demand but in our view, these are not insurmountable. As the LNG market continues to grow, the ability and appetite to enter into smaller, more flexible, contracting arrangements is becoming apparent. A perfect case study of how LNG imports have been anchored on a 'small' offtake is the Acajutla Power project in El Salvador. This project consists of a 378 MW ICE power plant with a direct connection to a dedicated FSRU (137,000m3). This project will be used to provide flexible and reliable energy to the grid in El Salvador.

Figure 17: Aerial view of the 378 MW Acajutla Gas Engine Power plant fed directly from the 137,000m3 FSRU BW Tatiana as seen in the distance.

The aggregation of gas demand through non-power users is also a key factor in reducing LNG costs and forming a part of that 'anchor' demand required for investment. It is also believed that adding more non-power users would support the enablement of a highly flexible Gas Power demand profile by acting as an offtake buffer to absorb the spikes in consumption.[19)] It should however be kept in mind that whilst we have shown Gas Power to be inelastic to gas price fluctuations, the same may not be true for non-power users who are likely to be more susceptible to gas price volatility and who in South Africa currently pays significantly lower gas prices than any new LNG supply option.[20)] This fact highlights the importance of adopting an effective LNG/gas contracting approach for the country which preferably consists of a mix of indices; tenures; and 'Take of Pay' obligations to find the best 'fit' between gas supply and demand profiles. To support this approach, we recommend that a central gas procurement office be established in South Africa to best optimize the mix of gas supplies to service South Africa's requirements.

We can't, however, ignore the immediate power crisis and whilst LNG solutions and regional supply options will be developed in due course,[21)] there is a need to add electrons onto the grid immediately (as reflected by the 850 MW of new ICE capacity built in 2023 in the Perfect World). One bridging solution that could be considered is to build multi-fuel ICE ('ICE DF') power stations that can operate on liquid fuels today but will seamlessly switch to gas and can later be converted to run on carbon neutral fuels when it becomes available. ICE DF power stations can switch between liquid and gas fuel sources even whilst in operations (Wartsila, n.d.) and there is no cost of conversions for when gas does become available. This ability to switch between fuel options introduces a myriad of additional benefits for the power projects and the power system, namely:

- Higher dispatch factors required during the System Contingency Reserve dispatch periods could be serviced by diesel whilst continuing with gas as the primary fuel option for the Flexible Peaking functionality;
- Diesel can be used in the event of a break in the gas supply chain (for example; if an FSRU is unable to delivery gas due to adverse sea conditions) thus ensuring high plant availabilities and;
- Diesel could be used in the off chance that LNG price exceeds that of diesel.

One drawback of the option to operate on diesel before gas arrives is that based on the South African Air Emissions Legislation today, liquid fuel plants of larger than 300 MWth would require some form of exhaust gas cleaning infrastructure in order to ensure compliance with the NOX emissions. This addition would deter the economics unless multiple projects of <120 MW can be built to avoid this requirement.

Lastly on the topic of gas supply, despite the uncertainty regarding the timing of potential H2 fuel options, there should be at least some degree of convertibility to H2 for future gas plants to mitigate or minimize the 'stranded asset' risk should natural gas not be allowed in the long term.[22)]

19) Any gas supply network, whether it be virtual pipelines or actual pipelines, has the ability to inherently store gas within its supply infrastructure. The bigger the supply network, the more ability to store gas and therefore manage the spikes in gas demand from Gas Power.

20) According to NBI, current gas users in South Africa pay ZAR30-90/GJ which is approximately 1/3 of the gas price assumed in this study (National Business Initiative, 2022).

21) There are a number of regional import initiatives which could service the Gas Power requirements in future. These include TNPA's LNG terminal project in Richards Bay (Creamer, 2022); the Beluluane Gas Company project in Mozambique (Beluluane Gas Company, n.d.); and the Total/Mulilo Coega project in Gqeberha (DMRE - IPP Office, 2022). The anticipated timing of these (and other) initiatives however varies with some of them potentially only being able to provide gas after 2026.

22) Reasons may include exorbitant costs; lack of global supply; or even policy decisions to further reduce emissions.

Reduced Concentration of Reserve Capacity

In today's power system, most operating reserves are provided by the coal fleet with an increasing reliance on the diesel OCGT's to balance the system as renewable penetration increases. Typically, a small fraction of a coal unit (~10%) capacity is allocated to providing such reserves. This approach however will not be sustainable as the coal fleet is decommissioned and there is an increasing reliance on gas and battery technologies to provide these reserves. New reserve providers must enter the system which our modelling shows to be a combination of BESS and Gas Power.

In the case where a Gas Power plant will be used to provide reserves, as the majority of the plant capacity would be dedicated to providing such reserves, and it is likely that any "large scale" Gas Power would provide the majority of required operating reserves, having such a large amount of system operating reserves concentrated into one plant represents a security of supply risk to the system. Should there be any issue with that 'Big Gas' power plant, then the whole power system may experience unexpected outages due to the lack of reserves available.

It is therefore recommended, from a total system integrity of supply perspective, that Gas Power be geographically spread across the grid through smaller, gas/fuel source diversified, plants in order to reduce the concentration risk.

Least Cost and Emissions

One often encounters a perception in the market that in order to reduce emissions, one must pay a premium as we saw during the introductory years of renewables which relied heavily on government subsidies. This, however, is no longer the case and renewables are undeniably the cheapest form of energy available today. And in order to achieve the least cost energy tariff, the generation mix should consist of technologies which enable the greatest amount of "cheap" renewable energy to be introduced into the system. Counterintuitively, as shown in our results (see section related to renewable curtailment), the addition of a carbon-based generation in the form of flexible natural gas ICE technology (together with BESS), reduces the system's reliance on more carbon intense and inflexible carbon emitters, such as diesel OCGT's and coal fired power generation, to balance the renewables. These emissions reductions, which without the addition of new Gas Power would be ~20% higher, are only possible thanks to the fast response times and high efficiencies across the entire output range of a typical ICE power plant (Wärtsila, 2022).

GAS POWER SOLUTION RECOMMENDATIONS

Our analysis and discussion has raised numerous findings and considerations which influences how South Africa could/should be approaching their future Gas Power endeavors. From this, we now provide guidance and definition around what a possible solution could look like.

From a technology perspective, highly flexible grid balancing engine technology, together with energy storage in the form of batteries, is the preferred route to provide flexibility to a future renewable power system. Many examples of utility scale engine power plants have been built with plants even reaching up to 573 MW per project (Wartsila, 2022) (Power Technology, 2015). And whilst South Africa needs several GW's to be erected in the coming years, it is prudent from both a gas supply and system reserves provider risk perspective to diversify both the geographic locations and fuel source options by building multiple, medium scale gas, multi-fuel power projects. This approach of having distributed Gas Power will also enable faster construction times (Clark, van Niekerk, Petrie, & McGregor, August 2022); rapid development of more regional gas resources;[23)] and greater job creation potential than would be seen through one or two 'Big Gas' projects. And as demonstrated in the Acajutla LNG-to-Power project, having a distributed approach may catalyze and unlock a multitude of potential new gas sources (both domestic and import) being developed thus creating further opportunity for cost savings and emission reductions in the downstream non-power sector.

A cursory view of the potential new gas sources indicates that there could be up to ten gas projects leveraging off at least seven different possible gas sources. And what's more is that the majority of these opportunities are located in areas which has sufficient grid capacity available as indicated in Figure 18.

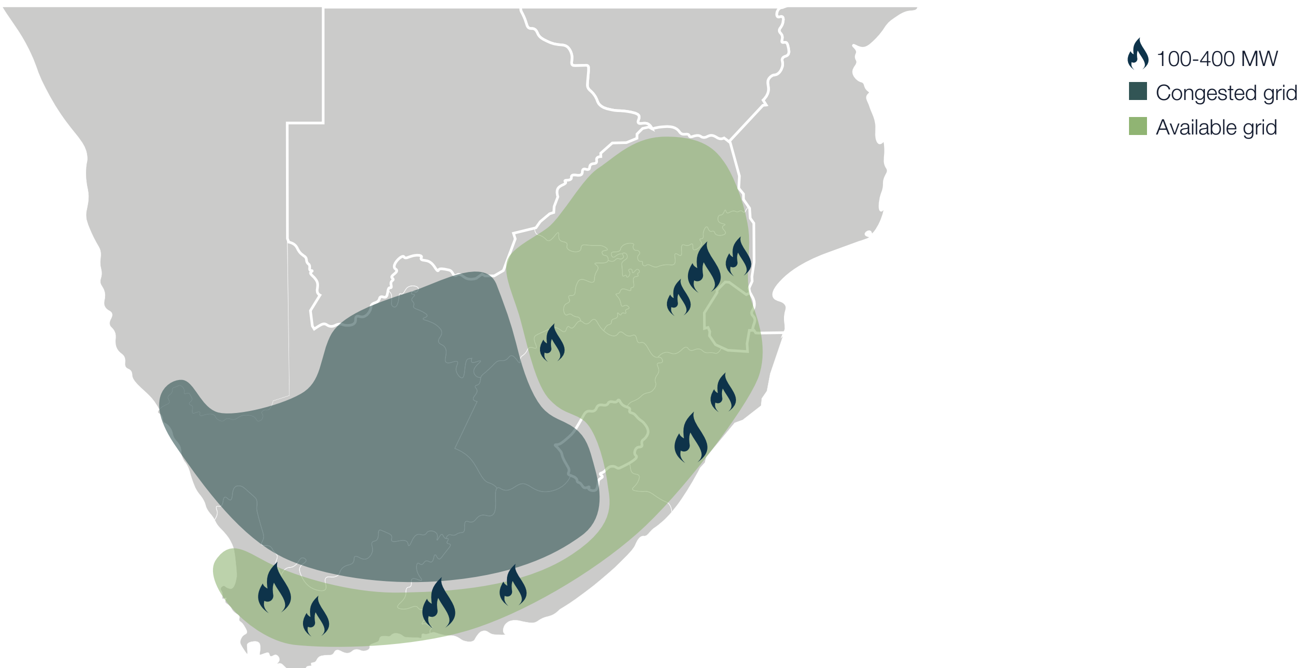


Figure 19:
Map of possible new Gas Power plants located at potential gas supply sources.

[23)] There are many smaller regional gas sources which could be fully developed through a Gas Power project. Examples include Renergen; Kinetiko; Kudu; etc…. (South African Oil and Gas Association, 2022)

This approach will also support the enablement of further emissions reductions beyond 2030 as we see a transition to greener future sustainable fuels such as Hydrogen which already today can be blended up to 25%.

In order to enact these recommendations, we believe that there should be a prioritization within the following areas of policy and procurement:

- Ensure that future IRP's adequately capture the value of flexibility and provide sufficient detail regarding the specific requirements of such flexibility (such as preferred technologies; capacity factors; roles in reserves; and minimum functional technology specifications); and
- Ensure that any upcoming gas IPP procurement programme sufficiently defines and values the need for flexibility as procured through multiple distributed; gas supply diversified; power projects.

AREAS OF FUTURE INVESTIGATION

We have identified the following areas of future investigation which we believe will add value concerning this topic of the role of gas in an energy crisis:

- An investigation into the practical limit of how much renewable can be built in South Africa is an important parameter to understand as it has a significant impact on how much of other technologies are built to meet the demand;
- Investigating the degree of flexibility and integrating any supply constraints which mimic real-life limitations one may encounter when considering the LNG supply chain and/or other gas supply options and;
- Investigating the possible changes in demand patterns caused by increased accessibility to embedded storage (eg: EV) and generation technologies.

CONCLUSIONS

This study set out to assess the adequacy of South Africa's proposed energy crisis mitigation measures (from a new-build capacity perspective) and to also understand whether there is a role for gas to power within this context and the future energy transition for South Africa. By virtue of the fact that the Planned World scenario yields virtually no load shedding over the next few years indicates that in theory, should South Africa manage to successfully execute all of the identified measures considered in this paper, then they can take comfort knowing that the current load shedding levels will soon be a thing of the past. However, based on experience, it is more likely that a fair portion of these measures will not be fully realized thus leaving the country with continued load shedding for the coming years at potentially levels significantly far worse than South Africa is currently experiencing. An effect which not only directly limits the economic growth of the country but also which indirectly accelerates the failure of the existing aged grid leading to further increases in extended load shedding.

The solution, as demonstrated in our "Perfect World" simulation, is to add as much renewable energy into the power system as possible through any means necessary but in parallel, flexibility in the form of BESS and Gas Power (based on ICE technology) needs to be added at scale. And whilst BESS is good for short term flexibility requirements, it is shown that Gas Power plays a far broader role in supporting the power system by providing a significant amount of both energy and operational reserves to the grid. Gas Power capacity factors can fluctuate between 1-30% in 'ideal' circumstances but grow to 60% when 'reality' creeps in. Similarly, up to 80% reserve capacity factors are called upon from Gas Power revealing that Gas Power plays a significant role as a operational reserves provider to the system. With this high degree of flexibility built into the system, South Africa can save $13B (13%) from the Planned World to the Perfect World and $26B (26%) from the Reality Check on the cumulative system costs up to 2032. Whichever way South Africa implements future Gas Power plants, there must be ample recognition of this wide range of dispatch profiles and the fact that gas acts as the system 'safety net' under any system contingency that may, and will likely, occur.

Counterintuitively, Gas Power has a significant role to play in reducing the net power system emissions by decreasing the reliance on coal and diesel to balance the system. Without building sufficient amounts of flexible Gas Power, South Africa's power emissions reduction trajectory would keep us diverted off the path to net-zero by 2050. And as an added benefit, again, contrary to common belief, by adding "expensive" gas to reduce emissions, one is also able to achieve the least cost for the system. A power system with 9 GW of flexible Gas Power by 2032 means that more renewables can be built thereby decreasing the total system cost. And in a world where no new fossil fuel plants are built, unrealistic amounts of battery capacity is required (shown to be approximately 3 GW / 24 GWh per year) and even nuclear is proposed in 2032 which incurs a 55% system cost premium with negligible (<1%) system emission reductions being achieved due to the continued usage of diesel and coal for our balancing needs.

Such flexible Gas Power additions could be integrated into the South African power system through multiple 100-400 MW; multi-fuel; geographically spread; gas source diversified; engine plants in order to reduce fuel supply price and availability risks and reducing the risk of concentrating the system's operational reserves providers. A cursory view of the gas market developments indicates a possibility to implement at least 10 such projects supplied from 7 domestic gas sources. Furthermore, there should also be some degree of convertibility to green fuel alternatives (estimated to be required beyond 2029) to ensure the continued realization of South Africa's energy transition to 100% renewables. In conclusion, whilst South Africa must continue to strive for the ideal world energy mix, which is dominated by renewable energy, it would be strongly advisable to continue undertaking flexible gas projects not only to support the rapid growth in renewables but to also ensure a stable supply should reality set in. To achieve this, we recommend that the next revision of the IRP provides further key details on the characterization of such flexibility (such as preferred technology; reserve requirements; and capacity factors) and that upcoming Gas Power IPP procurements should adequately value flexibility as part of their evaluation criteria. We believe that if South Africa can adapt their future Gas Power related policy and Gas Power procurement to align to the recommendations outlined in this report, they would be able to demonstrate to the world their leadership in the transition from a coal-based economy to a renewable based economy.

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WÄRTSILÄ

Date: 5th September 2022

Dearest Esteemed Colleague,

As of late, much has been discussed concerning how South Africa can eliminate load shedding and what steps should be taken for us to enjoy a stable; reliable; and cost-effective supply of electricity. Within such discussions, the role of gas-based power generation has often found itself under the spotlight and being subject to varying, and sometimes divisive, viewpoints. Questions concerning size; dispatch; technology; fuel supply; and even whether gas is needed at all have often been tabled with little consensus or agreement.

We, as Wärtsilä[i], using our in-house modelling capabilities, wish to demystify this topic by undertaking a **completely <u>transparent</u> power system modelling process**[ii]. You, as a key player in the energy sector, can now make your contribution into a data driven and evidence-based modelling exercise intended to create consensus and alignment on if and how gas power should/could be advanced in South Africa over the coming years. With your inputs, we wish to unpack how gas plays a role in three scenarios:

- ***"Perfect World"*** – A world with no restrictions on what new capacity can be built;
- ***"Planned World"*** – A world where all the initiatives and plans currently tabled[iii] are successfully executed; and
- ***"Reality Check"*** – A world where our new build plans *don't* go according to plan.

We therefore invite all interested and affected parties to be a part of this process by sharing their experience and expertise to assist in defining the input parameter dataset and scenarios to be modelled. Attached to this letter is a list of the key inputs[iv] currently considered for the modelling along with reference information where available.

Should you have a different view on the current input parameters, or you believe there is information missing, we will revise the input parameters provided the proposed changes are sufficiently justified (through the presentation of evidence-based facts that are publicly available) and will likely have a material impact[v] on the results.

In order to be a part of this initiative, there is a two-step process to follow:

1. Review the current input parameters and add a description of your proposed changes along with attaching any relevant supporting information.
2. Join us on a call (multiple engagement sessions will be arranged depending on the level of response) to discuss your proposed changes and address any clarification questions we may have.

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All validated inputs will be acknowledged in a White Paper targeted for completion in November 2022 and the results and model, will be made publicly available.

All comments and clarifications must be addressed to **Ms Keaobaka Poti** at keaobaka.poti@wartsila.com by the **30th September 2022**.

For those who wish to understand more about the modelling process and to see some examples that Wärtsilä has undertaken, we hereby invite you to attend a *"Power System Modelling by Wärtsilä - Introduction"* session to be held on the **14th September 2022 at 09:00 South African Time**. If interested, please send your names and email addresses to Ms Keaobaka Poti.

We look forward to engaging with yourselves and collectively taking meaningful steps forward to enrich and advance the discussions around gas power in South Africa!

Yours Sincerely,
Wayne Glossop
Senior Business Development Manager

Attachment 1 – Key Inputs and Scenarios

DISCLAIMER
*The information and conclusions in this document are based upon calculations (including software built-in assumptions), observations, assumptions, publicly available information, and other information obtained by Wärtsilä or provided to Wärtsilä by its customers, prospective customers or other third parties (the "**information**") and is not intended to substitute independent evaluation. No representation or warranty of any kind is made in respect of any such information. Wärtsilä expressly disclaims any responsibility for, and does not guarantee, the correctness or the completeness of the information. And whilst every reasonable effort is made to ensure the completeness and accuracy of our modelling, the calculations and assumptions included in the information may not necessarily take into account all the factors that could be relevant. Nothing in this document shall be construed as a guarantee or warranty of the performance of any Wärtsilä equipment or installation or the savings or other benefits that could be achieved by using Wärtsilä technology, equipment or installations instead of any or other technology.*

[i] Wärtsilä leads the transition towards a 100% renewable energy future. We help our customers in decarbonisation by developing market-leading technologies. These cover future-fuel enabled balancing power plants, hybrid solutions, energy storage and optimisation technology, including the GEMS energy management platform. Wärtsilä Energy's lifecycle services are designed to increase efficiency, promote reliability and guarantee operational performance. Our track record comprises 76 GW of power plant capacity and more than 110 energy storage systems delivered to 180 countries around the world. For more information, please visit us at https://www.wartsila.com/energy.
[ii] Wärtsilä uses PLEXOS®, the world's most powerful energy market simulation engine providing analytics and decision-support to modelers, generators, and market analysts— offering flexible and precise simulations across electric, water, gas and renewable energy markets (reference: https://www.energyexemplar.com/plexos).
[iii] Currently identified measures to alleviate the power crisis include accelerating IPPO procurement programmes (RMIPPP; REIPPP; Gas; BESS); improving the coal EAF; implementing DSM; executing all private IPP's currently being licenced with NERSA; purchase of excess capacity from existing generators; Eskom/World Bank BESS programme; high uptake of unlicenced embedded generation; and increase in power imports.
[iv] It is recognized that Plexos, as a highly sophisticated modelling software tool, has many more inputs that could be considered however, we have attempted to simplify these inputs to the ones that we know will have a significant impact on the results. However, as we refine and optimize the model, more detailed inputs would be gladly welcomed.
[v] In the modelling process, one always has to weigh the impact versus the cost (i.e. modelling resource usage and processing time impact) of adding in certain inputs. Our team of experienced modelers will be able to advise on how certain inputs will likely alter the outcome (if any) and whether or not it will change the conclusions in a material way.

Planned New Capacities	Scenario		I&AP Comments	Reference/Supporting Ma
	Planned World	*Reality Check*		
RMIPPPP	All RMIPPPP planned capacity is procured and operation by 2024	1/2 of the RMIPPPP planned capacity is procured and operation delayed by 1 year	Please provide as much information as possible on the reasoning behind your comments such as real life reference; independent studies; etc.	Please provide the name/type of document and/or website link where it can be accessed.
REIPPP PV	Planned additional capacity is procured and operational on time as per IRP with doubling of capacity as per Presidents speech in 2024	A 2 year delay on the procurement and operation of additional capacity (full capacities are maintained due to historical success of this programme in realising all the bidded MW's)		
REIPPP Wind	Planned additional capacity is procured and operational on time as per IRP with doubling of capacity as per Presidents speech in 2024	A 2 year delay on the procurement and operation of additional capacity (full capacities are maintained due to historical success of this programme in realising all the bidded MW's)		
IPP Gas Programme	Planned additional capacity is procured and operational on time which is 2026	A 2 year delay on the procurement and operation of additional capacity.		
Eskom 3GW Gas	Planned additional capacity is procured and operational in Richards Bay on time (which is before 2028 as per draft Ministerial Determination)	No procurement of additional capacity due to environmental concerns in Richards Bay.		
IPP BESS Programme	Planned additional capacity is procured and operational on time. Projects come online in 2024	A 2 year delay on the procurement and operation of additional capacity		
Future IPPO BESS Programme	1231MW to come online in 2029	1231MW to come online in 2031		
Eskom World Bank BESS - Phase 1 8	Planned additional capacity is procured and operational on time. Phase 1 is online in 2023 and Phase 2 is online 2025	A 2 year delay on the procurement and operation of additional capacity. Phase 1 is online in 2025 and Phase 2 is online 2027		
Private PV IPPs	Annual additional capacity of 1GW is procured	Annual additional capacity of 500MW is procured		
Embedded Renewables (rooftop PV	Growth of Embedded renewables at 500MW per anum	Growth of Embedded renewables at 250MW per anum		
Purchase of excess capacity from e	1000MW additional dispatchable capacity procured and operational for a three year period.	500MW additional dispatchable capacity procured and operational for a three year period.		
Demand Side Management	Demand Side Management implemented accordingly and on time	1/2 of Demand Side Management implemented with a 1 year delay		
Eskom Maintenance Programme -	Maintenance programmes implemented accordingly and on time	The maintenance programme yields half of the expected MW's and is delayed by 2 years.		
International Imports	International imports realised	No international imports realised		
Eskom Medupi & Kusile Coal Units	- Medupi Unit 4 online in 2024 - Kusile Units 5 and 6 online in 2023	Commercial operation of the coal units delayed by 2 years		
Energy Availability Factor : Eskom C	After the Eskom Maintenance programme is implemented; EAF is halved from 3% to 1.5% year-on-year.	After the delayed and reduced Eskom Maintenance programme is implemented; EAF resumes its current trajectory of 3% drop per year.		

Input Name	Input Number	Input Unit	Reference document	Reference	Wartsila Comment	Link	I&AP Comments	Reference/Supporting Material to be submitted
Installed capacity								
Eskom Coal Fleet	38773	MW	2021 Eskom Integrated Report	Page 136 - Baseload Stations, Coal-Fired	The model is based on total nominal capacity and not the total installed capacity. Nominal capacity according to the integrated report accounts for auxiliary requirements as well as ageing.	2021IntegratedReport.pdf (eskom.co.za)	Please provide as much information as possible on the reasoning behind your comments such as real life reference; independent studies; etc.	Please provide the name/type of document and/or website link where it can be accessed.
Kelvin B	420	MW	Kelvin Power Station - Information Summary	Page 2		- https://www.kelvinsale.com/pdf/Kelvin-Information-Summary.pdf		
Peakers - Dedisa OCGT IPP	355	MW	Independent Power Projects in Sub-Saharan Africa - Lessons from Five	Page 176 - The Peaker Project	Diesel is regarded as the primary fuel source	https://documents1.worldbank.org/curated/fr/795581467993175836/pdf/104779-PUB-		
Peakers - Avon OCGT IPP	670	MW	Independent Power Projects in Sub-Saharan Africa - Lessons from Five	Page 176 - The Peaker Project	Diesel is regarded as the primary fuel source	https://documents1.worldbank.org/curated/fr/795581467993175836/pdf/104779-PUB-		
Ankerlig OCGT	1327	MW	2021 Eskom Integrated Report	Page 136 - Peaking Stations	The model is based on total nominal capacity and not the total nstalled capacity. Nominal capacity according to the integrated report accounts for auxiliary requirements as well as aging.	2021IntegratedReport.pdf (eskom.co.za)		
Gourikwa OCGT	740	MW	2021 Eskom Integrated Report	Page 136 - Peaking Stations	The model is based on total nominal capacity and not the total nstalled capacity. Nominal capacity according to the integrated report accounts for auxiliary requirements as well as aging.	2021IntegratedReport.pdf (eskom.co.za)		
Nuclear	1860	MW	2021 Eskom Integrated Report	Page 136 - Baseload Stations	The model is based on total nominal capacity and not the total nstalled capacity. Nominal capacity according to the integrated report accounts for auxiliary requirements as well as aging.	2021IntegratedReport.pdf (eskom.co.za)		
IPPO CSP	600	MW	Eskom Data Portal - Renewable Statistics		Installed Capacity utilised in the model as per the data portal	https://www.eskom.co.za/dataportal/renewables-performance/renewable-statistics/		
IPPO PV	2212	MW	Independent Power Producers Procurement Programme (IPPPP) - An Overview (December 2021)	Page 11 - Technology contributions (Procured vs operational)		https://www.ipp-projects.co.za/Publications/GetPublicationFile?fileid=2d03d621-6dc4-ec11-956e-2c59e59ac9cd&fileName=20220318_IPP%20Office%20Q3%20Overview%202021-		
IPPO Wind	3442	MW	Eskom Data Portal - Renewable Statistics		Installed Capacity utilised in the model as per the data portal	https://www.eskom.co.za/dataportal/renewables-performance/renewable-statistics/		
Other IPPO Renewable	50,5	MW	IPP Projects Database		Other Renewables include Landfill Gas, Biomass, and Small Hydro Projects. Only projects in operational state were considered in the model. 70% Availability	https://www.ipp-projects.co.za/ProjectDatabase		
Hydro_Import	1500	MW	Integrated Resource Plan 2019	Appenix A, 6.1.1 - Municipal, Private and Eskom Generators (Page 53 - Table 8)	Hydro import from Cahora Bassa	http://www.energy.gov.za/IRP/2019/IRP-2019.pdf		
Hydro_RSA	600	MW	2021 Eskom Integrated Report		Based on Eskom Hydro Plants which includes Gariep and Vanderkloof. Model assumed 70% annual capacity factor with no flexibility	2021IntegratedReport.pdf (eskom.co.za)		
Embedded_base	2091	MW	- Integrated Resource Plan 2019 - Kelvin Power Station - Information Summary	Appenix A, 6.1.1 - Municipal, Private and Eskom Generators (Page 53 - Table 8)	- Capacity includes other non-Eskom municipal and private generators (Kelvin B, Sasol Infrachem Coal, Sasol Synfuel Coal, Sasol Infrachem Gas, Sasol Synfuel Gas, Colley Wobbles, Other non-Eskom Hydro, Steebras, Sappi, and Mondi power plants). - It should be noted that only 420MW of the 600MW Kelvin power station capacity was considered (essentially Kelvin B). - Kelvin A is on long-term outage as per the Kelvin power station website - Model assumes 50% availability of these power plants	http://www.energy.gov.za/IRP/2019/IRP-2019.pdf		
PS_Hydro	2732	MW	2021 Eskom Integrated Report	Page 136 - Peaking Stations, Pumped Storage Schemes	Includes Drakensberg; Ingula; and Palmiet	2021IntegratedReport.pdf (eskom.co.za)		
Embedded Renewables (PV Rooftop)	700	MW	Small Scale Embedded Generation - Guide for Small South African Municipal Distributors	Page 1 - Installed capacity of SSEG	Modelled as PV technology. This is also assumed to be included in the demand curve data obtained from the Eskom data portal.	https://www.sseg.org.za/wp-content/uploads/2021/03/SSEG-Distributors-Guide.pdf		
International Exports	0	MW	2021 Eskom Integrated Report	Page 88 - Export Growth Strategy	- Exports are therefore not included in the model as they are treated as interruptable supply	2021IntegratedReport.pdf (eskom.co.za)		
Fleet Assumptions								
Coal Retirement Schedule			Formal communication from Eskom	Table 1 - Station and unit decomissioning dates		https://cer.org.za/wp-content/uploads/2020/05/Formal-Response-PAIA-ref-0087-Man-Affirmation-that-records-does-not-exist.pdf		
Energy Availability Factor : Eskom Coal			Coal stations performance Jan 2021 to date		Current trend of year-on-year EAF reduction is approximately 3%.	Document: 0220715 Coal stations performance Jan 2021 to date_Chris Yelland.xlsx		
Energy Availability Factor : Nuclear	74	%	Power Reactor Information System		Indicated EAF of 73,4% for Koeberg 1 and 74,2% for Koeberg 2 Reactors for 2021. Average EAF of 74% used in the model	https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=836		
Plant Efficiencies - Existing Coal	30,61	%	2021 Eskom Integrated Report	Page 130 - Technical Statistics, Primary Energy	Overal thermal efficiency used for all coal thermal plants in the model.	2021IntegratedReport.pdf (eskom.co.za)		
Plant Efficiencies - Existing Eskom OCGTs	30	%	2021 Eskom Integrated Report	Page 130 - Technical Statistics, Primary Energy (Diesel and Kerosene usage for OCGTs)	Efficiency calculated from the diesel usage, calorific value and density of fuel.	2021IntegratedReport.pdf (eskom.co.za)		
Plant Efficiencies - Existing IPP OCGTs	30	%	2021 Eskom Integrated Report	Page 130 - Technical Statistics, Primary Energy (Diesel and Kerosene usage for OCGTs)	IPP OCGTs assumed to have the same efficiency as Eskom OCGTs	2021IntegratedReport.pdf (eskom.co.za)		
Plant Efficiencies - Existing Nuclear	33	%	Energy Education - Nuclear Power Plants			https://www.nuclear-power.com/nuclear-engineering/thermodynamics/laws-of-thermodynamics/thermal-efficiency/thermal-efficiency-of-nuclear-power-plants/		
Plant Efficiencies - New Build (NB) Coal	32,9	%	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	- Efficiency assumption in the model is based on the average between heat rates of the low and high cases - Model assumed 80% annual Load Factor	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Plant Efficiencies - New Build Nuclear	32,7	%	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	- Efficiency assumption in the model is based on the average between heat rates of the low and high cases - Model assumed 80% annual Load Factor	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Plant Efficiencies - New Build OCGT	38,3	%	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	- Efficiency assumption in the model is based on the average between heat rates of the low and high cases - Model assumed 80% annual Load Factor	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Plant Efficiencies - New Build ICE	47,4	%	Wartsila Internal		Based on internal experience and observations			
Plant Efficiencies - New Build CCGT	52,3	%	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	- Efficiency assumption in the model is based on the average between heat rates of the low and high cases - Model assumed 80% annual Load Factor	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Fuel Price								
Coal	2,03	USD/GJ	2021 Eskom Integrated Report		Fuel price calculated based on the indicated output production, as well as fuel cost. Model assumed 17 USD/ZAR exhange rate.	2021IntegratedReport.pdf (eskom.co.za)		
Uranium	0,57	USD/GJ	2021 Eskom Integrated Report	Page 128 - Technical Statistics (Electricity output)	Fuel price calculated based on the indicated output production, as well as fuel cost. Model assumed 17 USD/ZAR exhange rate.	2021IntegratedReport.pdf (eskom.co.za)		
Diesel - Eskom Peakers	13,71	USD/GJ	2021 Eskom Integrated Report	Page 87 - Use of open-cycle gas turbines	Fuel price calculated based on the indicated output production, as well as diesel usage. Model assumed 17 USD/ZAR exhange rate.	2021IntegratedReport.pdf (eskom.co.za)		
Diesel - IPP Peakers	20,19	USD/GJ	2021 Eskom Integrated Report	Page 87 - Use of open-cycle gas turbines	Fuel price calculated based on the indicated output production, as well as diesel usage. Model assumed 17 USD/ZAR exhange rate.	2021IntegratedReport.pdf (eskom.co.za)		
Gas	15	USD/GJ			- Assumed gas price is delivered gas price to the power station - Assumptions based on internal Wartsila experience and market observations			
Fixed Operational Costs								
Existing & New Build Coal	60,1	USD/kW/yr	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Fixed operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Existing & New Build Nuclear	130,5	USD/kW/yr	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Fixed operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Existing & New Build OCGT	14,1	USD/kW/yr	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Fixed operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
NB ICE	15	USD/kW/yr	Wartsila Internal		Based on internal experience and observations			
NB CCGT	16,5	USD/kW/yr	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Fixed operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Variable Operational Costs								
Existing & New Build Coal	3,8	USD/MWh	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Variable operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Existing & New Build Nuclear	4,3	USD/MWh	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Variable operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
Existing & New Build OCGT	4,6	USD/MWh	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Variable operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		
NB ICE	7,5	USD/MWh	Wartsila Internal		Based on internal experience and observations			
NB CCGT	3,9	USD/MWh	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 18 - Levelized Cost of Energy, Key Assumptions	Variable operatoinal cost assumption in the model is based on the average between the low and high cases	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf		

Planned New Capacities						
RMIPPPP	1995	MW	IPP Risk Mitigation		Projects under RMIPPP treated as one generating unit in the model with the following assumptions: - Dispatch times of 5:00 to 21:30 daily (according to xxx) - COD at Q4 2024 - Decommisioning at 2022 (based on the PPA tenor) - Tariff at ZAR/kWh 1,83 (based on average of ZAR/kWh 1,63 with a 2 year CPI escalation)	https://www.ipp-rm.co.za/
REIPPP Round 5 - PV	1000	MW	Independent Power Producers Procurement Programme (IPPPP) - An Overview (December 2021)	Page 45 - Background	Assumed COD at Q1 2025 and Once-off capacity addition	https://www.ipp-projects.co.za/Publications/GetPublicationFile?fileid=2d03d621-6dc4-ec11-956e-2c59e59ac9cd&fileName=20220318_IPP%20Office%20Q3%20Overview%202021-22%20WEB%20VERSION.PDF
REIPPP Round 5 - Wind	1600	MW	Independent Power Producers Procurement Programme (IPPPP) - An Overview (December 2021)	Page 45 - Background	Assumed COD at Q1 2025 and Once-off capacity addition	https://www.ipp-projects.co.za/Publications/GetPublicationFile?fileid=2d03d621-6dc4-ec11-956e-2c59e59ac9cd&fileName=20220318_IPP%20Office%20Q3%20Overview%202021-22%20WEB%20VERSION.PDF
REIPPP Round 6 - PV	2000	MW	President Cyril Ramaphosa: Address to the nation on energy crisis		Assumed COD at Q1 2026 and Once-off capacity addition	https://www.gov.za/speeches/president-cyril-ramaphosa-address-nation-energy-crisis-25-jul-2022-0000
REIPPP Round 6 - Wind	3200	MW	President Cyril Ramaphosa: Address to the nation on energy crisis		Assumed COD at Q1 2026 and Once-off capacity addition	https://www.gov.za/speeches/president-cyril-ramaphosa-address-nation-energy-crisis-25-jul-2022-0000
REIPPP Round 7-onwards (PV)	1000	MW	Consultation Paper: Concurrence with the Ministerial Determination on the Procurement of new Generation capacity of 14 771MW from renewables (solar PV and wind) and storage technologies.		- Assumption that capacity is additional on an annual basis inline with IRP timeframes	https://www.nersa.org.za/wp-content/uploads/2022/08/Updated-Consultation-Paper-s38-determination-14-771MW-Renewables-Storage.pdf
REIPPP Round 7-onwards (Wind)	1600	MW	Consultation Paper: Concurrence with the Ministerial Determination on the Procurement of new Generation capacity of 14 771MW from renewables (solar PV and wind) and storage technologies.		- Assumption that capacity is additional on an annual basis inline with IRP timeframes	https://www.nersa.org.za/wp-content/uploads/2022/08/Updated-Consultation-Paper-s38-determination-14-771MW-Renewables-Storage.pdf
IPP Gas Programme	3000	MW	Ministerial Determination		Based on RFP's from DBSA for advisory services related to this programme under the IPPO, it states that the targetted COD date is in 2026. Furthermore, Ministerial determinations requires the capacity to be online before 2027.	https://www.gov.za/sites/default/files/gcis_document/202009/43734gon1015s.pdf
Eskom 3GW Gas	3000	MW	Consultation Paper: Concurrence with the Ministerial Determination on the Procurement of New Generation Capacity of 3000 MW from Gas Technology	Page 10 - Procurement Process under the IPP Procurement Prorgamme	The recent released NERSA determination indicates Eskom as the buyer of new generation capacity. Based on this, we believe and have assumed that 3GW of gas generation capacity will be procured in addition to the proposed 3GW Gas capacity as per the IPP programme	https://www.nersa.org.za/wp-content/uploads/2022/08/Updated-Consultation-Paper-s38-determination-3-000-MW-Gas.pdf
IPPO BESS Programme	513 / 2052	MW / MWh	Ministerial Determination		The Ministerial Determination states that this capacity should be online by 2022 however, this programme is already delayed but due for imminent release. We therefore assume that this capacity will be online by 2024.	https://www.gov.za/sites/default/files/gcis_document/202009/43734gon1015s.pdf
FUTURE IPPO BESS Programme	1231 / 4924	MW / MWh	Consultation Paper: Concurrence with the Ministerial Determination on the Procurement of new Generation capacity of 14 771MW from renewables (solar PV and wind) and storage technologies.		Assumed that this is a 4hr LiIon battery	https://www.nersa.org.za/wp-content/uploads/2022/08/Updated-Consultation-Paper-s38-determination-14-771MW-Renewables-Storage.pdf
Eskom World Bank BESS - Phase 1	199 / 833	MW / MWh		AFDB Website	Assumed that liIon technology is considered	https://www.afdb.org/en/documents/south-africa-eskom-distributed-battery-energy-storage-project-project-appraisal-report
Eskom World Bank BESS - Phase 2	160 / 640	MW / MWh		AFDB Website	Assumed that liIon technology is considered	https://www.afdb.org/en/documents/south-africa-eskom-distributed-battery-energy-storage-project-project-appraisal-report
Private PV IPPs	6000	MW	President Cyril Ramaphosa: Address to the nation on energy crisis		Private PV IPPs under Nersa Licensing according to the speech. However, it is not realistic to believe that all 6GW would be built and built in one year. It is all assumed to be based on PV technology.	https://www.gov.za/speeches/president-cyril-ramaphosa-address-nation-energy-crisis-25-jul-2022-0000
Embedded Renewables (PV Rooftop)	ssumed to already be con		Eskom Medium-Term System Adequacy Outlook 2022-2026 report	Page 13 - 6.3: Self-generation: Estimated rooftop PV	- Model assumptions on generation capacity addition are In line with MTSAO report, thereafter assumptions of 500MW annual generation capacity additions is assumed based on observed trend.	https://www.eskom.co.za/wp-content/uploads/2021/11/MediumTermSystemAdequacyOutlook2022-2026.pdf
Purchase of excess capacity from existing generators - Other	1000	MW	Consultation Paper: Concurrence with the Ministerial Determination on the Procurement of New Generation Capacity of 3000 MW from other Distributed Generation	Page 7 - New generation capacity from other technology	As the public NERSA consultation document outlines the need for baseload capacity, the model assumes dispatchable generators for annual capacity addition.	https://www.nersa.org.za/wp-content/uploads/2022/08/Updated-Consultation-Paper-s38-determination-1-000MW-other-technologies.pdf
Demand Side Management	1500	MW	Eskom Top CEOs Engagement Session (29 July 2022)	Page 4 - Reducing Demand		Presentation: Eskom Top CEOs Engagement Session (29 July 2022) - TO BE FILED IN DATA ROOM
Eskom Maintenance Programme - 1	1800	MW	Eskom Top CEOs Engagement Session (29 July 2022)	Page 6 - Overview of annual capacity that can be connected	- COD at Q4 2024 - Maintenance programme on Coal fleet	Presentation: Eskom Top CEOs Engagement Session (29 July 2022) - TO BE FILED IN DATA ROOM
Eskom Maintenance Programme - 2	1800	MW	Eskom Top CEOs Engagement Session (29 July 2022)	Page 6 - Overview of annual capacity that can be connected	- COD at Q4 2025 - Maintenance programme on Coal fleet	Presentation: Eskom Top CEOs Engagement Session (29 July 2022) - TO BE FILED IN DATA ROOM
Eskom Medupi & Kusile Co	2394	MW	Eskom Presentation to the Joint Portfolio Committee on Public Enterprises & Mineral Resources and Energy: System Status and Outlook	Page 15 - Overview of estimated additional capacity over 36 months (MW	- Medupi Unit 4 online in 2024 - Kusile Units 5 and 6 online in 2023	Presentation: Eskom Presentation to the Joint Portfolio Committee on Public Enterprises & Mineral Resources and Energy: System Status and Outlook - TO BE FILED IN DATA ROOM
International Imports	200	MW	Article from news24		Capacity modeled as not available during peak according to the source	https://www.news24.com/news24/southafrica/news/breaking-botswana-offers-off-peak-electricity-to-supplement-eskom-supply-20220727
Load Curves						
Annual Demand Curve			Eskom data portal			https://www.eskom.co.za/dataportal/demand-side/
Peak demand			Eskom data portal			https://www.eskom.co.za/dataportal/demand-side/
Load Projections						
Peak demand by 2035	46000	MW	Eskom Top CEOs Engagement Session (29 July 2022)	Page 3 - Insights	Eskom CEO preso Approximate linear growth of the peak demad until 2035 is assumed	Presentation: Eskom Top CEOs Engagement Session (29 July 2022)
New build CAPEX Assumptions						
Coal	4587,5	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	CAPEX assumption in the model is based on the average between the low price case of USD 2950 and a high case scenario of USD 6225	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
Nuclear	10300	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	CAPEX assumption in the model is based on the average between the low price case of USD 7800 and a high case scenario of USD 12800	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
OCGT	812,5	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	CAPEX assumption in the model is based on the average between the low price case of USD 700 and a high case scenario of USD 925	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
CCGT	1000	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	CAPEX assumption in the model is based on the average between the low price case of USD 700 and a high case scenario of USD 1300	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
ICE	747,5	USD/kW			Based on internal references	
Wind	1187,5	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	CAPEX assumption in the model is based on the average between the low price case of USD 1025 and a high case scenario of USD 1350	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
PV - Utility Scale	875	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	CAPEX assumption in the model is based on the average between the low price case of USD 800 and a high case scenario of USD 950	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
CSP	7545	USD/kW	Lazard's Levelized Cost of Energy Analysis - Version 15.0	Page 11 - Capital Cost Comparison	- CAPEX assumption in the model is based on the average between the low price case of USD 6000 and a high case scenario of USD 9090 - Referred to as Solar Thermal Tower with Storage in the Lazard Report	https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf
BESS (Li-Ion)	360	USD/kWh	BNEF Report			Bloomberg Report (paid study)
BESS (Flow)	560	USD/kWh	Email from Bushveld Minerals			Email from Bushveld Minerals with indicative prices
Pump Storage	2600	USD/kW	Wikipedia site on the Ingula Pump Storage project	Capex reference for Ingula project	We based our new pump storage capex inputs on the recently completed Ingula pump storage project which cost $3.5B for 1332MW.	https://en.wikipedia.org/wiki/Ingula_Pumped_Storage_Scheme

ANNEXURE B – DESCRIPTION OF APPROACHES AND ASSUMPTIONS ON KEY MODELLING INPUTS

INPUT CATEGORY	DESCRIPTION
Coal (and Nuclear) Fleet availability	The starting coal fleet availability was determined from the operational statistics presented in the Eskom Annual report (Eskom, 2021). This equates to approximately 55%. There was also an allowance to shift 7% of the planned maintenance within the year as Eskom currently does by undertaking their maintenance in the summer months in order to increase availability during winter. For Nuclear, an availability of 70% based on a view taken of the average availability of Koeberg in recent years (Eskom, 2022).
Reserves	Reserve requirements were extrapolated from the System Operator's 'Ancillary Services Technical Requirements for 2022/23 – 2026/27' (Eskom, 2022). Spinning reserve amounts derived from the culmination of Instantaneous and Regulating Reserves with an annual increase of 30MW; 35; 40; 45MW; 50MW per annum up to 2032 respectively. The above normal increase is attributed to the rapid increase in renewable penetration that is anticipated in the system. Non-spinning reserve allocations were derived from the Ten-minute reserve allocations in the Eskom Ancillary Services report. Whilst there is a small decrease in this value between 2022 and 2026, we have assumed a flat line requirement for these reserves up until 2032 due to the increased renewable penetration. For batteries operations, the minimum state of charge is 12%. The principal approach when deciding how much of the battery capacity can provide spinning reserves is that it must be able to provide this for at least 30min. The rest of the battery capacity, which in the case of a 4hr battery is 88% of the remaining capacity, can be used for energy shifting applications*. Coal is allowed to provide spinning reserves. CCGT can only provide spinning reserves and OCGT and ICE can provide non-spinning 10-min reserves and spinning reserves for the balancing needs.
Demand curve and growth	Assumptions around demand curves have a significant impact on what capacity gets built. Typically, as with the IRP, there would be various high; medium; low growth scenario trajectories however, to simplify our analysis, we have only considered a single growth trajectory of 2.5% per annum. This is inline with the assumptions taken by Eskom (deRuyter E. -A., 2022). The demand curve was extrapolated from current demand curves as obtained from the Eskom data portal (Eskom, 2022).
Renewable new build limitations	It is important to acknowledge that there is a practical limit as to how much renewable energy can be built in a single year. Such limitations may be caused by multiple factors such as global supply chain constraints; supply constraints of local component/services; and readiness of the grid to rapidly absorb large amounts in a short time. Views on what this limit could be for South Africa vary so in the absence of widely documented literature being available, we have adopted a view based on our experience of power systems in other countries. Based on Wärtsilä's experience of modelling over 200 power systems, we believe that a 10% of peak demand is a reasonable new build renewable (wind and PV) limit to consider.
Technology Capex and Opex	The majority of capex and opex inputs were obtained from the Lazard's levelized cost of Energy Analysis – Version 15.0 (Lazard, 2022). Exceptions to this include capex and opex for the Lithium Ion Energy Storage; Vanadium Flow Energy Storage; and Internal Combustion Engine technology. We have considered Bloomberg New Energy BESS price predictions for LiIon batteries and data for Vanadium Flow Batteries was obtained from Bushveld Minerals. Data for Internal Combustion Engine's was obtained from Wärtsilä internal data resources. For pump storage capex, we considered the latest costs from the recently completed Ingula Project which was $3.5B for 1335MW (Wikipedia, 2022).
Fuel Costs	Coal (2$/GJ); diesel (Eskom: 13.71$/GJ; IPP: 20.19$/GJ); and Nuclear (0.57$/GJ) fuel costs were derived from the Eskom Integrated Report (Eskom, 2021). Regarding diesel, the view has been taken that future diesel power plants would consider a fuel cost relating to an IPP and not the Eskom price which benefits from reduced levies. The remaining fuel cost is that of gas which is treated as a variable in this analysis but assumed to be sourced predominantly through LNG imports. Power plant delivered gas price is 15$/GJ which is the midway price as determined by the range of gas prices Eskom believes will be available (deRuyter A. , 2022). A sensitivity at 10$/GJ has also been considered.
Demand Response	Whilst this could be a significant contributor to the system stability, the rules of the DR programme mean that the annual contribution is minimal with only 200 events of 10minute dispatches modelled (Eskom, 2022).
Renewable Dispatch	Baseline dispatch data for the renewables (wind and solar) was obtained from the Eskom data portal (Eskom, 2022) and linearly extrapolated according to the MW's installed. It is recognized that there may be

	some aggregation effects when more renewables are on the system however, this has not been considered for this study.
Technology learning curves	Costs associated with the Electrolyzes used in the 'Power-to-H' generation option have been obtained from Lappeenrata University. Renewable learning curves were taken from BNEF H1 2022 "Learning curves 2023" and for BESS, BNEF H2 2021 "Learning curves 2023".

*Note: It can be noted that to date, the BESS procured under the Eskom/WB programme has been required to provide a range of ancillary services however, the primary function cited is to provide daily energy shifting capabilities hence in our view, the assumptions made here seem to be reasonable.

ANNEXURE C – DESCRIPTION OF SCENARIO ASSUMPTIONS

	Planned New Capacities	Scenario		Comments
		Planned World	Reality Check	
1	RMIPPPP	All RMIPPPP planned capacity, which includes the 1995MW awarded in this programme, is procured and operation by 2024	1/2 of the RMIPPPP planned capacity is procured and operation delayed by 1 year only coming online in 2025	Delay reason: The RMIPPP projects are already delayed by almost 1.5 years with there still being no firm Financial Close date in sight (except for the Scatec Kenhardt 1,2,3 projects which reached FC in June 2022). We therefore believe it is not impossible for another year delay through further FC extensions and potential project delays. Allocation reason: It is widely known that project prices have escalated well above normal rates in the past year which has possibly made some projects unfeasible. There is also uncertainty whether some projects, in particular, the powerships totalling 1.2GW, will receive all their authorizations to proceed. Therefore, a view that only half of the capacity will be closed. Also to add that in the Perfect World, we only have the three Scatec Kenhardt projects confirmed totalling 150MW.
2	REIPPP Round 5, 6, and beyond.	Planned additional capacity is procured and operational on time as per IRP with doubling of capacity as per Presidents speech in 2024	A 2 year delay on the procurement and operation of additional capacity	Delay reason: REIPPP 6 is still being tendered and is due for submissions in Oct 2022. Whilst REIPPPP has shown it can run programmes on time, there are strong external factors including the surge in demand for renewable energy across Europe (due to the stoppage of Russian gas supplies) which may either influence pricing or even production capacity allocations available for South Africa. Allocation reason: To date, the IPP Office have shown excellent success rates in terms of reaching >90% COD for the awarded projects and there is no reason to deviate from this trend now (DMRE - IPP Office, 2021).
3	IPP Gas Programme	Planned additional capacity is procured and operational on time which is 2026	A 2 year delay on the procurement and operation of additional capacity.	Current timelines for new gas is planned COD before 2026. However, with the global demand for gas concentrated in Europe and there being a general lack of gas and FSRU's in the market today (Elliott, 2022), it is very reasonable to assume that there could be a 2 year delay on obtaining any gas or FSRU's for South Africa.
4	Eskom 3GW Gas	Planned additional capacity is procured and operational in Richards Bay on time (which is before 2028 as per draft Ministerial Determination)	No procurement of additional capacity due to environmental concerns in Richards Bay.	Delay reason: Whilst it is not 100% confirmed (at the time of writing this) whether this 3GW capacity replace or augments the 3GW in the IRP already approved in the Ministerial Determination from September 2020, we assume that it is an additional capacity understood to be at the request of Eskom and inline with their 3GW project in Richards Bay. This project however has recently experienced a significant setback as the Minister of Environmental Affairs has placed the EIA authorisation on review following objections by environmental lobbyists (Natural Justice, 2022) (News24, 2022). This may potentially kill the project entirely for Eskom hence we assume that no project proceeds under Reality Check.
5	IPP BESS Programme	Planned additional capacity is procured and operational on time. Projects come online in 2024	A 2 year delay on the procurement and operation of additional capacity	Delay reason: The current anticipated release date for the IPP BESS programme is Sept/Oct 2022 and whilst there is no apparent reason to believe this will be delayed, as this is a first time the IPPO is procuring BESS, there may be some unexpected delays during the procurement process (as was seen in the first REIPPP). Furthermore, there is also significant risk that due to the global surge in demand for BESS, that capacity may not be as readily available in the market. There is also additional risk in the fact that the majority of LiIon

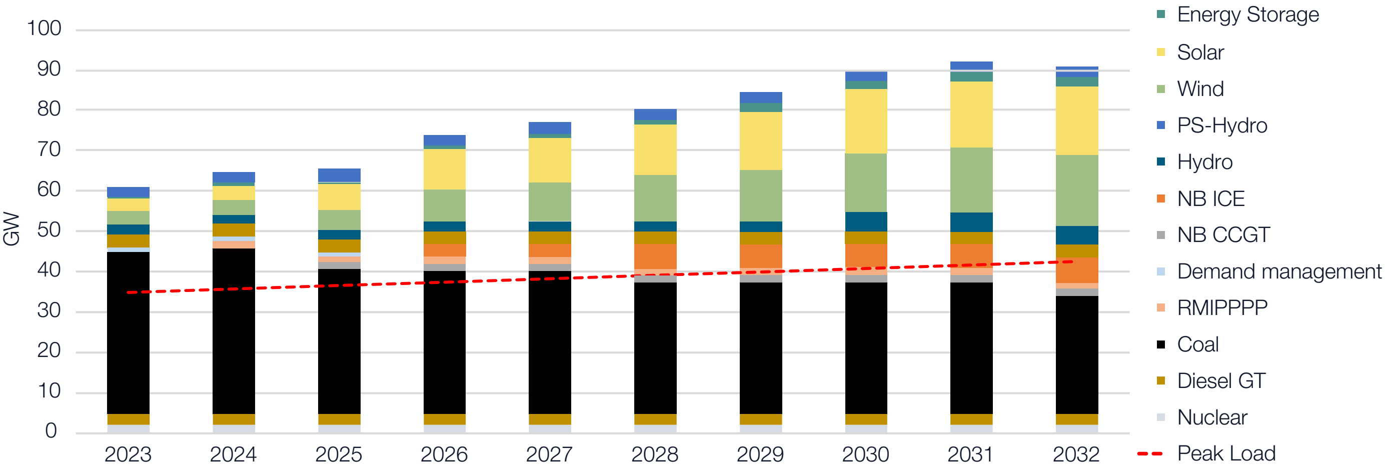
				batteries are supplied out of China and should there be any issues (such as Shanghai port lockdowns as recently experienced (McKinsey, 2022)), this could add further delays onto the projects.
6	Future IPPO BESS Programme	1231MW to come online in 2029	1231MW to come online in 2031	This is a recent addition inline with the draft Ministerial Determination as published by NERSA for comments. Timing for this capacity should be "as soon as reasonably possible in line with the timetable set out in Table 5 of the IRP 2019" (NERSA, 2022). The IRP indicates that this capacity should be online in 2029. In Reality check, we add a 2 year delay due to reasons not yet revealed to us.
7	Eskom World Bank BESS - Phase 1 & 2	Planned additional capacity is procured and operational on time. Phase 1 is online in 2023 and Phase 2 is online 2025	A 2 year delay on the procurement and operation of additional capacity. Phase 1 is online in 2025 and Phase 2 is online 2027	The Eskom/World Bank programme was originated due to the failure to undertake the planned CSP project as part of the loan agreement between Eskom and WB for the Medupi project (Moyo, 2018). This project, originated in 2010, then morphed into a 1440MWh BESS project in 2017 (African Development Bank, 2022). There were two phases, first phase of 800MWh was to be completed by December 2020 and the second of 640MWh to be completed by December 2021. There have already been significant delays on this programme with only the first phase having been awarded in June 2022 and the second phase not yet tendered (Engineering News, 2022). In our Planned World, we assume Phase 1 comes online in 2023 and Phase 2 only in 2025 (due to the fact that procurement could take almost a year as it has in Phase 1). In reality check, we only consider a delay of 2 years on each phase. Such extensive delays are not abnormal with projects undertaken by Eskom as has been seen with the recent coal new-builds.
8	Private PV IPPs	Annual additional capacity of 1GW is procured	Annual additional capacity of 500MW is procured	There is currently 6GW worth of projects undergoing the license application process (South African Government, 2022). However, given the recently relaxed requirements imposed by NERSA in order to obtain a license (such as not requiring a PPA), it is difficult to ascertain which project will proceed or not. Our view is that it is not realistic to assume that all 6GW will be executed immediately hence we assume that in the Planned World, 1GW is built every year and in Reality Check, 500MW is built every year. To add further uncertainty around this number, it is likely that the current draft ERA which removes the cap for license applications may increase these estimations.
9	Embedded Renewables (rooftop PV)	Growth of Embedded renewables at 500MW per year	Growth of Embedded renewables at 250MW per year	An annual embedded renewable (roof top PV) capacity of 500MW has been derived from Eskom's Medium-term System Adequacy Outlook 2022-2026 (Eskom, 2022). This report however does recognize that there is uncertainty but an indication that it may be approximately correct is that the equivalent value of PV panel imports was 500MW over the previous year (Reuters, 2022).
10	Purchase of excess capacity from existing generators - Other	1000MW additional dispatchable capacity procured and operational for a three year period.	500MW additional dispatchable capacity procured and operational for a three year period.	This is inline with the draft Ministerial Determination which is currently available for public comments (NERSA, 2022). The capacity sought for is 1000MW but the maximum PPA duration is only 3 years hence it is primarily targeted at accessing spare capacity within existing generators or rental type solutions. The Realistic scenario takes a view that only half of this could be realised as it is not unreasonable to assume that a significant portion of the available spare capacity may not be available due to maintenance/fuel constraints.
11	Demand Side Management	Demand Side Management implemented accordingly and on time	1/2 of Demand Side Management implemented with a 1 year delay	

12	Eskom Maintenance Programme - 1 & 2	Maintenance programmes implemented accordingly and on time which introduces 1.8GW in 2024 and an additional 1.8GW in 2025.	The maintenance programme yields half of the expected MW's and is delayed by 2 years. Therefore, only 900MW is added in 2025 and another 900MW in 2026.	Eskom have given priority to undertaking maintenance on their coal boilers and their requests to simplify the procurement of such services directly with OEM's has even been supported at the presidential level (South African Government, 2022) (Engineering News, 2022). Estimates are to add 3.6GW through this maintenance however, due to the age and extend of damage of the equipment, there is significant risk that there would be delays and reduced performance from such initiatives (deRuyter E. -A., 2022).
13	International Imports	International imports realised	No international imports realised	
14	Eskom Medupi & Kusile Coal Units	- Medupi Unit 4 online in 2024 - Kusile Units 5 and 6 online in 2023	Commercial operation of the coal units delayed by 2 years	Eskom are planning to have repairs on Medupi Unit 4 completed by 2024 and the final Kusile Units 5 and 6 online in 2023 (deRuyter E. -A., 2022). In our Reality check, based on the historical delays experienced by both of these projects, we take a view that all three of these units will experience a 2 year delay in reaching Commercial Operation.
15	Energy Availability Factor : Eskom Coal	After the Eskom Maintenance programme is implemented; EAF is halved from 3% to 1.5% year-on-year.	After the delayed and reduced Eskom Maintenance programme is implemented; EAF resumes its current trajectory of 3% drop per year.	Over the past years, the rate of coal fleet availability has been steadily declining (as is anticipated for equipment reaching the end of their life). In recent years, the trend is close to reach a reduction of 3% EAF drop per year. In the Planned World, we assume that Eskom will be able to continue their aggressive maintenance initiatives and thereby reduce the EAF drop to only 1.5% per year. In Reality Check, we take a view that the 3% drop per year will continue in a linear fashion.
16	Koeberg Availability due to maintenance	Koeberg, which is currently undergoing maintenance, is fully operational by 2023.	There is a 2 year delay in the maintenance of one Koeberg unit causing there to be only half the capacity available until 2025.	The maintenance of Koeberg has already experienced some delays and continues to experience them as seen with the recent incident whereby the boiler was dropped in China (News24, 2022).
17	Diesel Supply to OCGT's	It is assumed that there are no restrictions on the amount of diesel that can be supplied to these plants.	Diesel supply is restricted to the equivalent of 40% capacity factor.	During periods of high demand, it is not uncommon for Eskom to run out of diesel to supply their OCGT's (Smit, 2022).
18	Future IRP Hydro Import	The 2500MW as per IRP comes online in 2030.	No new future hydro import is realized.	There is a large amount of uncertainty around the timing and probability of hydro projects in the region hence the view has been taken that in Reality Check, it may not happen at all within the study time frame.

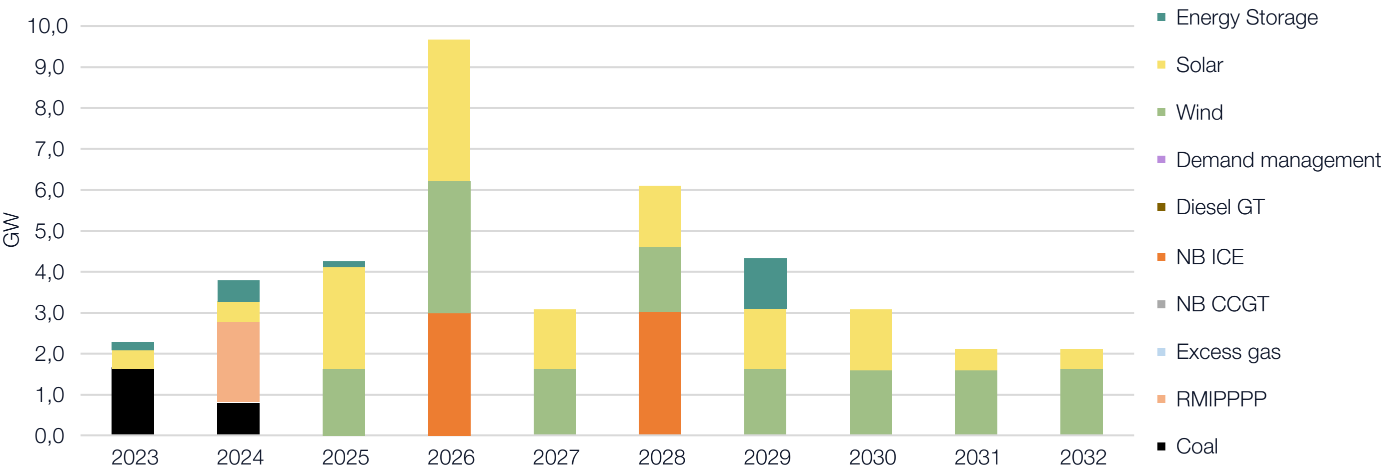
ANNEXURE D – NEW BUILD AND ENERGY SHARE GRAPHS

Planned World new capacity additions; installed capacity; and energy shared.

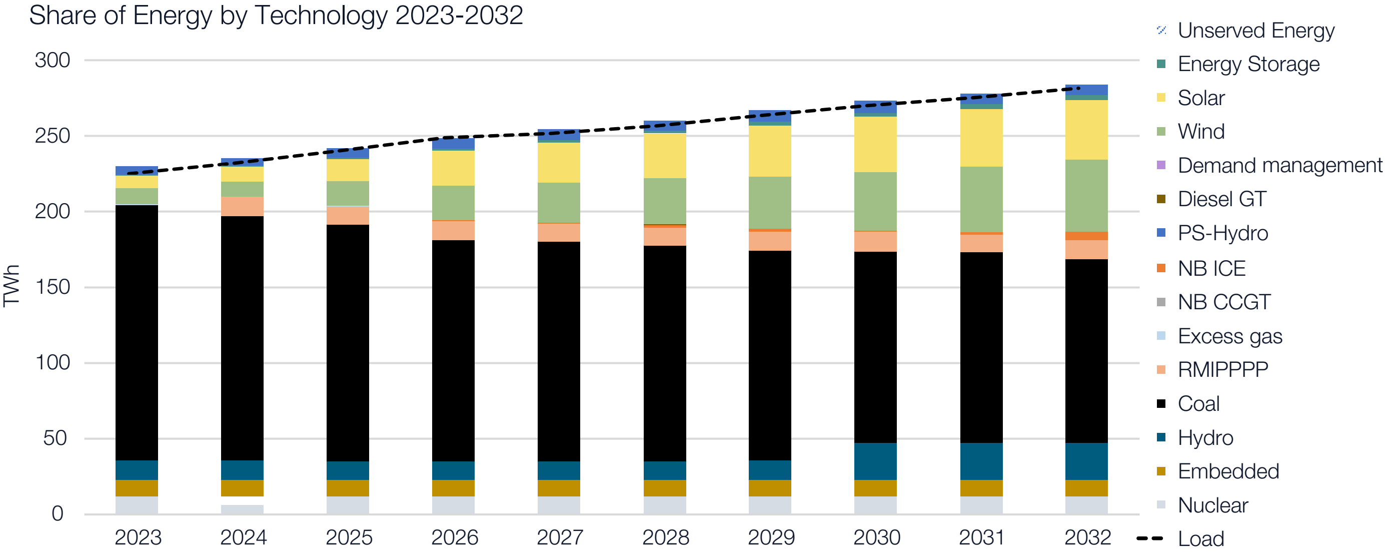
Installed Capacity 2023-2032



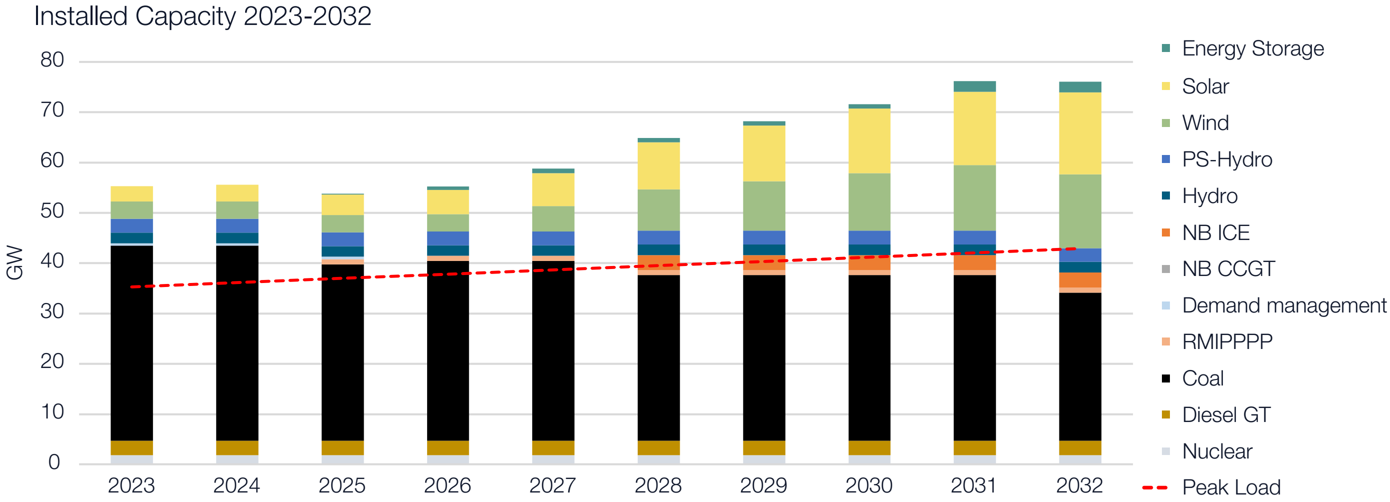
Annual Capacity Built 2023-2032

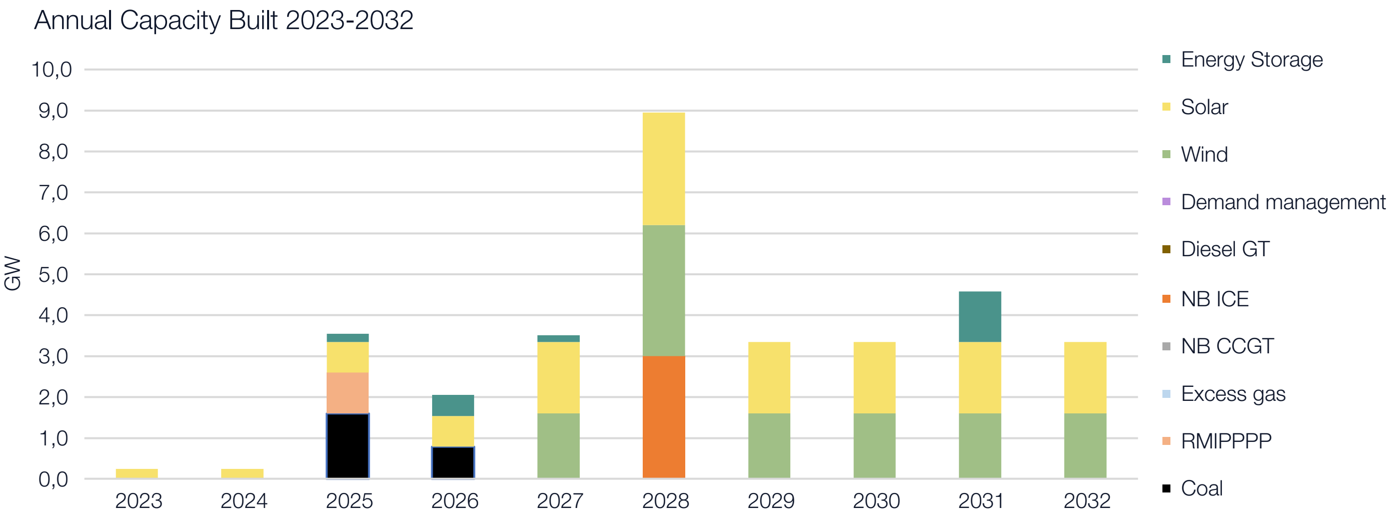


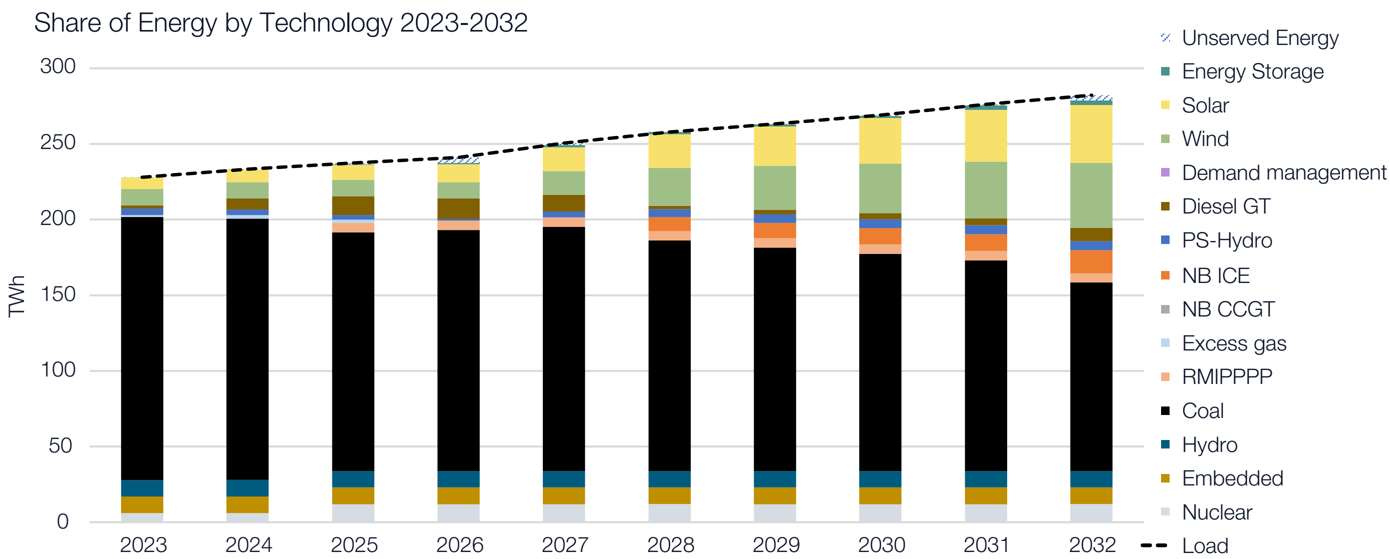
Share of Energy by Technology 2023-2032



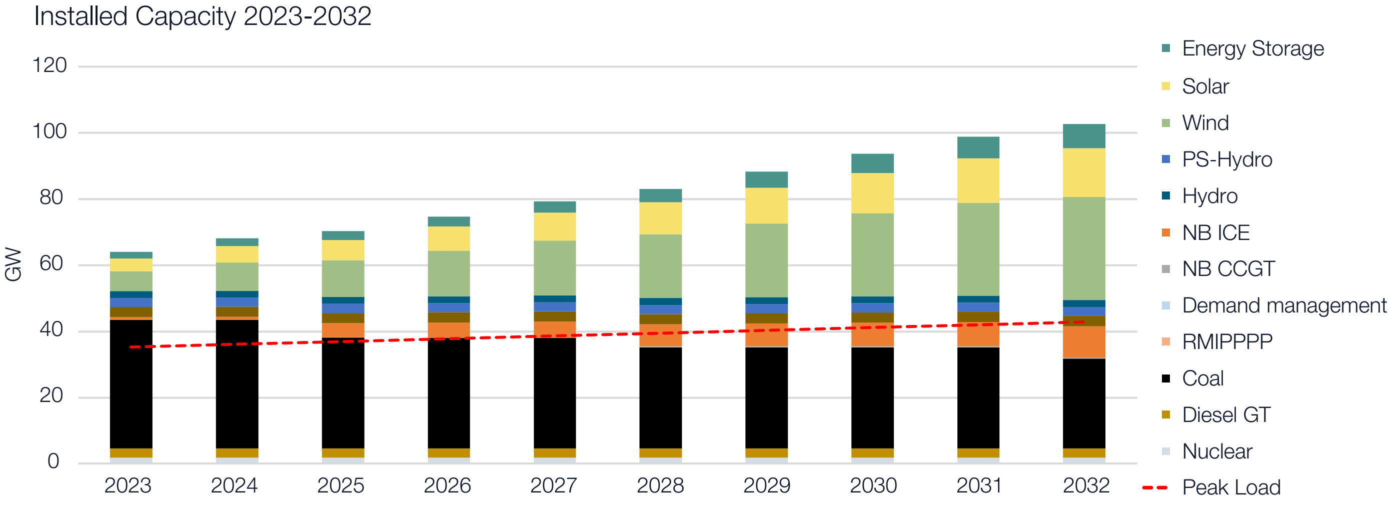
Reality Check new capacity additions; installed capacity; and energy shared.

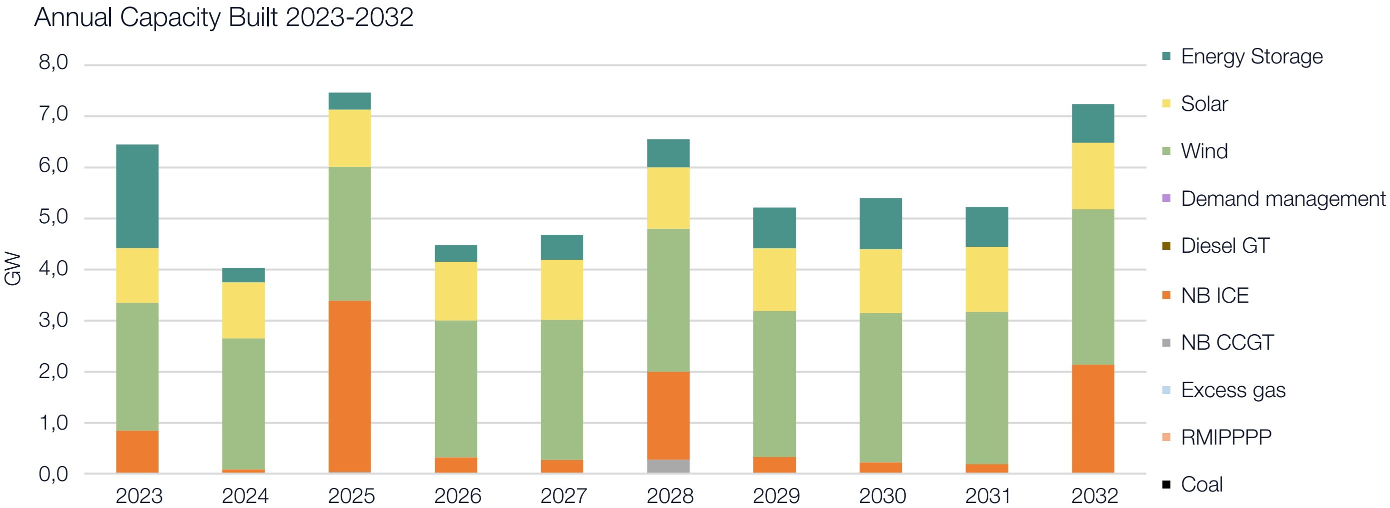


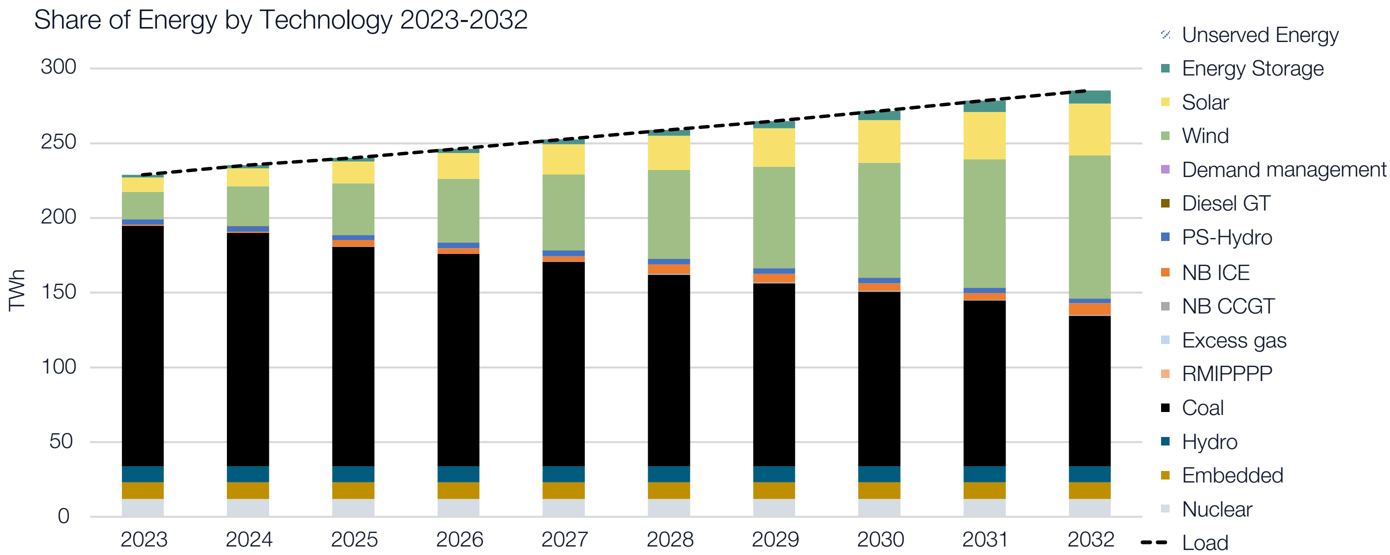


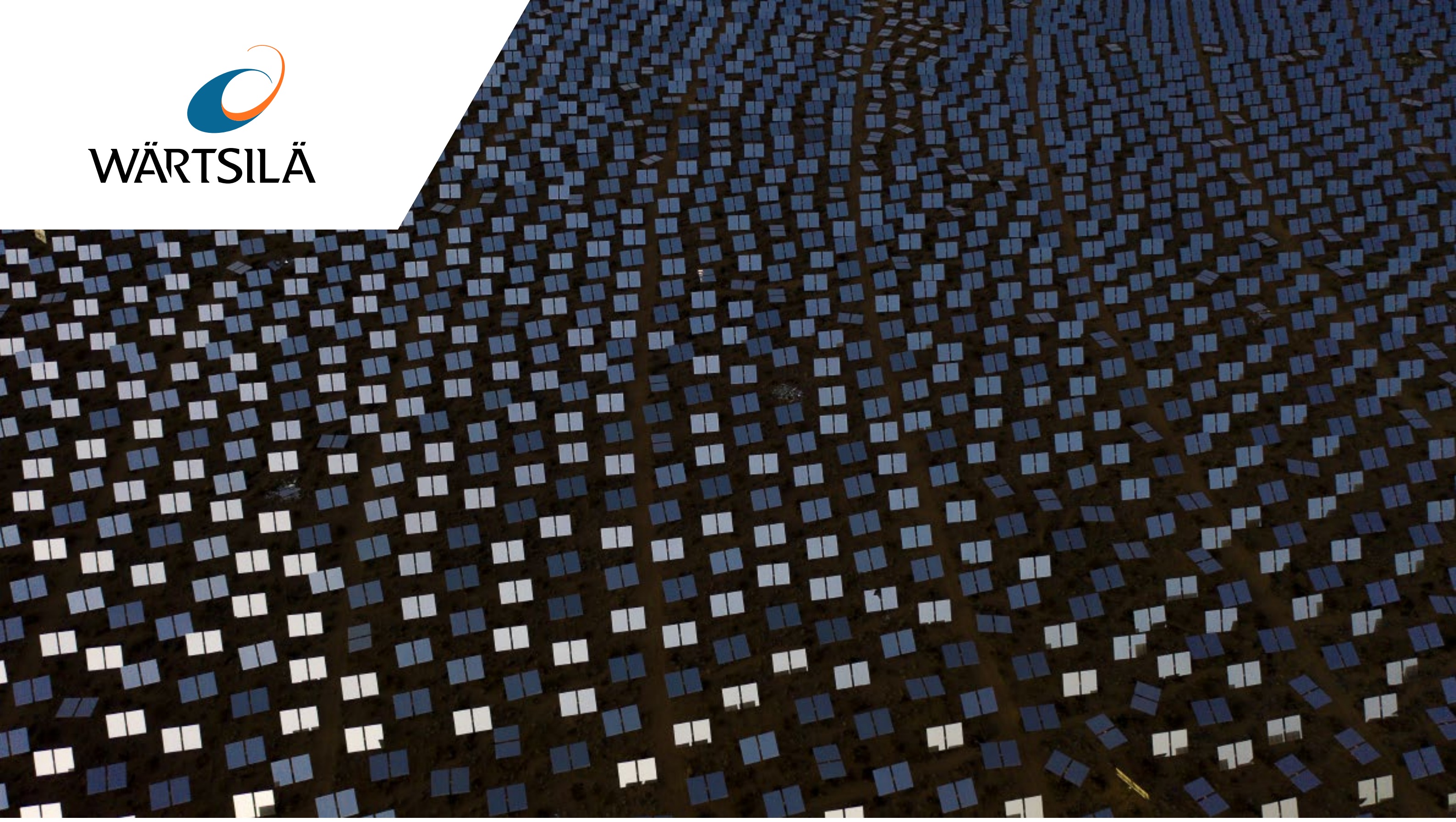


Perfect World new capacity additions; installed capacity; and energy shared.









ABOUT WÄRTSILÄ

Wärtsilä leads the transition towards a 100% renewable energy future. We help our customers to decarbonise by developing market-leading technologies. These cover future-fuel enabled balancing power plants, hybrid solutions, and energy storage and optimisation technology, including the GEMS energy management platform. Wärtsilä Energy's lifecycle services are designed to increase efficiency, promote reliability and guarantee operational performance. Our portfolio comprises 76 GW of power plant capacity and more than 110 energy storage systems delivered to 180 countries around the world.

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