Imperial College London

WHITE PAPER SERIES:
The flexibility of gas: what is it worth?

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SUSTAINABLE GAS INSTITUTE
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preface

sustainable gas institute

imperial college london's sustainable gas institute (sgi) is a unique academic-industry partnership, and a ground-breaking collaboration between the united kingdom and brazil. the institute is multidisciplinary and operates a global open innovation model, based at imperial college london and collaborating with leading universities in brazil. the sgi manages, leads and delivers world-class research with global partners across the spectrum of science, engineering, economics and business.

the aims of the institute are to:

- examine the environmental, economic and technological role of natural gas in the global energy landscape;
- define the technologies and develop energy systems models that could explore the role of gas and other energy sources;
- help to advance technology roadmaps to support future industry r&d investment decisions; and
- address the global challenge of how to mitigate climate change.
Executive summary

Gas networks are inherently flexible and valuable assets in many energy systems globally. There is an ongoing debate regarding their use to provide support for energy system decarbonisation, as low carbon electricity is expected to provide an increasing share of demand. One important perceived value of gas, whether natural gas, biomethane or hydrogen, is that it may provide flexibility at relatively low cost, helping to support daily and seasonal variation in demand. Arguments in support of gas networks suggest that electricity systems will find it difficult to maintain flexibility on their own, whilst also reducing greenhouse gas emissions and dramatically increasing capacity. Gases, on the other hand, could provide flexibility at relatively low cost and may be produced and used with relatively low greenhouse gas emissions.

The gas network provides flexibility in a number of different ways, including:

- The ability to shift the timing of supply over short or daily timescales through flexibility in pipelines (linepack) and short-term storage; and
- The ability to move supplies over longer or seasonal timescales through seasonal gas storage, as well as imports through interconnector pipelines from neighbouring countries or through liquified natural gas from exporters separated by greater distance.

The existence of a gas network in the future will also allow other flexibility mechanisms such as hybridisation between gas and electricity and power to gas technologies, which will increase the coupling of electricity and gas infrastructures.

The estimates of gas network flexibility value depend on the characteristics of the flexibility needed, including timescales and spatial factors, and the competing flexibility options. In addition, not all ways of providing flexibility rely on natural gas. This competition will ultimately affect the value of flexibility services in a market environment.

However, if we are to maintain gas networks in the future, their design will fundamentally change in order to meet climate change targets. These changes will develop over time and will have a changing and fundamental impact on flexibility provision. Understanding these changes and their impact on flexibility and value is important to future emissions reduction and the development of robust systems with which to deliver it.

This white paper examines these issues in detail through a systematic review of the currently available evidence on gas network flexibility value, focusing on types of flexibility, their capacity and estimated value across different markets.
Key findings

1. Gases such as natural gas, hydrogen and biomethane are inherently storable and transportable energy carriers, and can be a valuable component of a flexible future energy system.

Natural gas has delivered seasonal energy demand at an additional cost of less than 0.5 p/kWh in the UK, Europe and the United States between 2015 and 2020, and sometimes as low as approximately 0.05p/kWh in Europe and the United States.

The value of linepack in managing daily flexibility needs is also highlighted in modelling studies, potentially providing profit increases or cost savings for both gas producers and gas consumers.

There is a significant opportunity for gas networks to continue to contribute to flexibility in the future, though changes to gas networks will be necessary.

The value of operating gas and electricity networks as an integrated energy infrastructure has received increasing attention in research and could provide significant opportunities to deliver on both climate commitments and increasingly mismatched energy supply and demand conditions.

2. Natural gas and gas networks provide flexibility for daily and seasonal variation in demand, and increasingly electricity supply, to deliver energy to consumers when needed. This includes:

- flexibility in gas production;
- flexible gas electricity generation;
- gas network linepack, or the gas stored as pressurised gas in gas pipes, which is flexed to meet the daily fluctuation in gas demand for gas consumers connected to the gas network;
- natural gas storage, such as underground geological gas stores and surface storage facilities, which can be used for both daily and seasonal flexibility; and
- gas imports through pipeline and LNG (liquefied natural gas) terminals.

In the future, new types of flexibility provided by gas could become increasingly important, such as power to gas to maximise the utilisation of renewable energy generators and hybridisation of end-use between electricity and low carbon gas, to reduce peak demand on the increasingly burdened electricity system.

3. The cost of providing flexibility through a gas network appears to reduce as the networks become increasingly interconnected with other countries through pipelines or LNG infrastructure, or through increasingly flexible domestic production.

Summer-winter price spreads (an indicator of the cost of shifting gas delivery from summer to winter in order to meet seasonal energy demand patterns), in the UK, Europe and the United States appear to be reducing.

Between 2005 and 2020 UK summer-winter price spreads reduced in the order of 70% (Figure ES1) and in Europe between 2008 and 2018 they reduced by nearly 90%. Between 2014 and 2016 summer-winter price spreads in the United States reduced in the order of 70%, though this is a snapshot and not necessarily a longer-term trend.

Interconnection and LNG trade has increased in the UK and Europe, and this is a significant driver of the reduction in summer-winter price spreads. For the United States, increased domestic gas production has contributed to reduced price spreads.
A further indicator of this is the reduction in gas storage capacity, which appears increasingly challenging as international gas markets have become more connected, thus providing competition to provide the inter-seasonal flexibility in the delivery of primary energy.

4. The future gas network will change to meet climate change targets, fundamentally changing its role in providing flexibility to the energy system

Climate targets will force gas networks to change. For example, estimates for gas use in Europe suggest that achieving 100% reduction in emissions might result in a 30% to 45% reduction in gas use by 2050, with hydrogen and other low carbon gases making up 75% to 80% of all gas use. These changes may include:

- The fragmenting and shrinking of gas networks as other low carbon vectors are preferred;
- The introduction of low carbon gases to the gas network, including hydrogen and biogas;
- The isolation of gas networks until international trade in low carbon gases is developed;
- The reduction in the typical energy density of the gas transported by the network as hydrogen is introduced, affecting the capacity and costs of flexibility mechanisms such as linepack and underground gas storage.

These changes in gas networks are likely to place an increasing burden on linepack and gas storage as the flexibility mechanisms in the initial transition to low carbon gas networks. This is a reverse of the trend in the current gas network which has seen reduction in storage and an increase in international imports, successfully delivering cost reduction. This indicates that future gas networks might not be able to deliver flexibility as cheaply as natural gas networks currently do.

5. Gas networks provide low cost flexibility in studies that examine the future costs and emissions in whole energy systems.

In UK modelling studies, the whole system costs in hydrogen, electricity,
and hybridisation focussed scenarios are found to be similar, though cost benefits appear possible when electricity and gas infrastructures are more integrated and hybridising opportunities are included. This benefit is equivalent to a ~5 percent annual system cost reduction when comparing an electrification-based scenario and a hybridised gas and electric scenario under a net zero emissions target, though this is subject to significant uncertainty about future costs.

A similar story exists in Europe, where studies show gas playing an important role in providing flexibility to support the increased penetration of renewables, and providing peaking energy to heat in the domestic sector to support electricity and heat pumps. At the same time, the introduction of hydrogen and biomethane reduces the emissions associated with gas, with some estimates suggesting gas reducing from 800 gCO₂-eq/kWh to the order of 100 gCO₂-eq/kWh by 2040.

In global modelling studies, increasing penetration of intermittent renewable energy technologies is linked to a decrease in the use of gas, and the reduction in systems costs for the same emissions outcome. However, natural gas and hydrogen still feature in these scenarios, in part for their flexibility characteristics.

6. Gas networks can deliver flexibility with relatively low greenhouse gas (GHG) emissions, though a more important contribution to GHG emissions could come from carrying low-carbon gasses such as hydrogen or biomethane.

The gas network provides flexibility at a relatively small energy penalty and therefore GHG emissions. The gas networks own use of gas increases between summer and winter leading to additional GHG emissions in the order of 1-2 gCO₂-eq/kWh, though this is declining over time (Figure ES2). This can be compared to the combustion emission of natural gas of 184 gCO₂/kWh.

The future of gas networks, and the impact of low carbon gases on the GHG emissions of flexibility provision in the future has not been examined in depth in the literature and is an interesting area for future study.

![Figure ES2](https://example.com/figure_es2)

**Figure ES2**

GHG emissions per unit flexibility and historic gas consumption

Note: Calculated as the winter demand minus summer demand for Grid own use.
7. Opportunities in developing gas markets such as Brazil exist but are limited by the extent of existing infrastructure.

Currently, gas has a limited role in Brazil due to the relative lack of existing pipeline infrastructure (largely concentrated in the south east), particularly with domestic and commercial consumers and with energy supply dominated by low carbon hydroelectric power generation. Some estimate future natural gas penetration in electricity generation at 4% to 7%.

However, in Brazil there is a role for flexible gas power generation to support hydroelectric stations and the increasing penetration of intermittent renewable electricity generation.

There is a significant potential for biogas and biomethane to play a role in this decarbonisation given the biomass potential in the sugarcane industry. These can either be for sale or to generate power in high efficiency thermal plants. However, increased infrastructure will be necessary to connect these plants to existing gas networks. Estimates suggest up to 20% of São Paulo State natural gas consumption could come from sugarcane mills by connecting all plants within 20km of the existing gas network.

As in other regions, the use of power-to-gas technology as a way to manage curtailment in renewable electricity generation may also be relevant in the Brazilian context, and the maintenance or extension of gas infrastructure will help to maximise the value of power-to-gas in the future.

The significant challenge for countries like Brazil with low-carbon electricity already prevalent in the electricity system is how to utilise the flexibility value of gas without significantly increasing emissions and endangering climate commitments.

8. Considerations for policy.

Natural gas has traditionally been able to provide flexibility, particularly seasonal flexibility for heat, at relatively little cost, and this has become cheaper in recent years as import markets have increased. However, maintaining gas networks whilst also reducing GHG emissions will require changes to the gas network that will fundamentally influence their flexibility. While a significant international market in biomethane or hydrogen trade does not exist, the burden of flexibility provision will lie with linepack and storage. Policymakers should be aware that the flexibility provision, and the cost of providing it, will change after a transition to low carbon gas networks.

A key element of the success of gas networks is their increasing connectivity to international gas trade. This is an element that will be missing in the transition to low carbon gas networks. If decisionmakers pursue low carbon gas networks as part of a strategy to address greenhouse gas emissions, then support for the establishment of international hydrogen and biomethane trade might make a valuable contribution to the low-cost flexibility of the future gas system.

In hybrid scenarios, where gas may play a small but important role in meeting peak energy demand, climate targets can still be met. However, maintaining gas networks with relatively small volumes of gas will be challenging and will require changes to pricing and business models, and may need policy support to be successful.

Research suggests that the costs of operating and maintaining the gas network under hybrid heat pump scenarios with low gas volumes is affordable when compared to hydrogen or electricity focussed scenarios that meet the same emissions reduction.
9. There are a number of opportunities for future research into the value of gas network flexibility in the future energy system:

The emerging demonstration of various aspects of future gas networks provides significant opportunities for research in flexibility provision and costs resulting from these fundamentally different gas systems. Research to examine these issues alongside the development of demonstration projects should be pursued to keep abreast of emerging data and keep policy makers informed of those developments and their implications for decision making.

Scenario modelling in the UK suggests that total system costs are relatively even across different scenarios that include gas networks, including natural gas, hydrogen and hybrid solutions. Work to understand the spatial and consumer aspects of those solutions in more detail would be valuable to help understand how and where gas networks make the most useful contribution in a future energy system that requires a range of solutions to flexibility challenges.

The impact of changing linepack and storage energy density on costs of delivering flexibility is another area that warrants additional study.

Better understanding of the costs of operating gas networks with relatively low gas flows is an emerging research priority, particularly given the positive performance hybrid scenarios have seen in modelling studies. This should include examination of the business models and pricing structures that will be necessary to fund gas networks despite decreasing gas flows and increasingly variable demand flows.

Finally, an examination of what is lost in the value of gas network flexibility by moving to smaller, fragmented networks is an area for future research. A key aspect of fragmented networks is the lack of imports through pipelines and liquified gas routes. This research should also include projections of timescales for development of international trade of hydrogen and their impact on the economics and flexibility of future gas networks.
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<th>Description</th>
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<tr>
<td>ANP</td>
<td>National Agency of Petroleum, Natural Gas and Biofuels</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbines</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
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<tr>
<td>DE</td>
<td>Distributed Energy</td>
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<td>DSM</td>
<td>Demand Side Management</td>
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<td>EC</td>
<td>European Commission</td>
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<td>EMF</td>
<td>Energy Modelling Forum</td>
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<td>GA</td>
<td>Global Ambition</td>
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<td>GDP</td>
<td>Gross domestic product</td>
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<td>GHG</td>
<td>Greenhouse gas</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IRR</td>
<td>Internal rate of return</td>
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<td>LNG</td>
<td>Liquefied natural gas</td>
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<td>NBP</td>
<td>National Balancing Point</td>
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<tr>
<td>NDC</td>
<td>Nationally Determined Contribution</td>
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<td>NECP</td>
<td>National energy and climate plans</td>
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<td>NT</td>
<td>National Trends</td>
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<tr>
<td>NGCC-CCS</td>
<td>Natural gas combined cycle – carbon capture and storage</td>
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<td>P2G</td>
<td>Power to gas</td>
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<td>SGI</td>
<td>Sustainable Gas Institute</td>
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<tr>
<td>SDS</td>
<td>Sustainable Development Scenario</td>
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<tr>
<td>TPA</td>
<td>Technology and Policy Assessment</td>
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<tr>
<td>TTF</td>
<td>Title Transfer Facility</td>
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<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>UKERC</td>
<td>UK Energy Research Centre</td>
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<tr>
<td>VoLL</td>
<td>Value of Lost Load</td>
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<td>WEO</td>
<td>World Energy Outlook</td>
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**Energy Units**

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<th>Unit</th>
<th>Description</th>
<th>Conversion</th>
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<tbody>
<tr>
<td>BTU</td>
<td>British Thermal Unit</td>
<td></td>
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<tr>
<td>MMBTU</td>
<td>Million British Thermal Unit</td>
<td></td>
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<tr>
<td>Ej</td>
<td>Exajoules</td>
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<tr>
<td>Wh</td>
<td>Watthours</td>
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<tr>
<td>kWh</td>
<td>Kilowatt hours 1,000 Wh</td>
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<td>Megawatt hours 1,000,000 Wh</td>
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<td>GWh</td>
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The White Paper Series

The aim of the Sustainable Gas Institute (SGI) White Paper Series is to conduct systematic reviews of literature on topical and controversial issues of relevance to the role of natural gas in future sustainable energy systems. These white papers provide a detailed analysis on the issue in question, along with identifying areas for further research to resolve any shortcomings in our understanding. The reviews also examine key future technologies and provide a critique of assessment processes.

If you want to read more about the White Paper Series, please visit the Sustainable Gas Institute website: (www.sustainablegasinstitute.org/white_paper_series)

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Any opinions stated within this report are the authors’ only.
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1. Introduction

There is an increasing debate regarding the use of gas networks to provide support for energy system decarbonisation, where the majority of effort is expected to come from the electricity system [1-5]. The perceived value of gases is that they may provide relatively low cost flexibility, helping to support daily and seasonal variation in demand, and increasingly intermittent supply, as renewable electricity generation increases as a proportion of the electricity mix [4]. Arguments in support of gas suggest that electricity systems will find it difficult to maintain flexibility on their own, whilst also reducing greenhouse gas emissions and dramatically increasing capacity [4].

Gases, on the other hand, are expected to continue to provide flexibility at relatively low cost, and may be produced and used with relatively low greenhouse gas emissions [4].

The gas network may provide flexibility in a number of different ways, and the value of flexibility will likely vary over these differing flexibility approaches and their characteristics, timescales, and across geographies. The gas delivered by networks can either be used directly (for example to provide heat for domestic, commercial or industrial consumers) or to fuel electricity production. In addition, not all ways of providing flexibility rely on natural gas [6]. This competition will ultimately affect the value of flexibility services in a market environment.

The Sustainable Gas Institute (SGI) at Imperial College London has conducted a systematic review of the available evidence surrounding the flexibility value of gas networks to bring clarity to the debate. This white paper presents the findings of that review, exploring the technical characteristics, market value and implications for carbon emissions. While much of the debate arises in countries where the use of gas networks is already common, implications for these options in other countries are also explored.

1.1. THE CONTEXT
Global climate change targets have led to a growing share of electricity in serving consumer energy demands. Intermittent renewable energy generation has played an increasing role in meeting that energy demand, with gas generation as backup support to the electricity system, both currently and in long-term energy...
scenarios. This has led to an increasing interdependency between gas and electricity networks and a growing need for global electricity and gas systems to operate in a more integrated and flexible way [7].

Natural gas networks provide a significant energy service in the flexible delivery of energy across timescales and locations. In the UK the gas network can provide in-day flexibility through linepack in the order of up to 300 GWh in the local gas network and 400 GWh in the National Transmission System [8], equivalent to approximately 18% of peak daily demand in 2018 [8, 9] (Figure 1). The daily gas demand seen in the UK gas transmission system can vary in the order of 3000 GWh/day between summer and winter, and is met through a combination of interconnection, domestic gas production and gas storage [10, 11]. Similarly, across Europe seasonal monthly gas demand may vary in the order of over 300 TWh/month between winter and summer months [12].

Gas networks’ ability to deliver this level of daily and seasonal flexibility is a central argument in the debate around repurposing gas networks in the future.

The ways in which natural gas can provide flexibility can broadly be categorised in three groups:

- Gas network flexibility, including:
  a. Gas storage options, including geological storage and surface storage technologies operating from daily to seasonal timescales [14];
  b. The linepack storage capacity of natural gas networks [8];

- Flexible electricity generation [15]; and

- Hybridisation capabilities, including:
  a. Domestic scale hybrid heat pumps [16];
  b. District scale hybrid heat generation for heat networks; and
  c. Power-to-gas systems to utilise renewable electricity generation during periods of low demand [6].

The value that these flexibilities can provide to the energy system varies, and can be measured in a number of ways [17, 18]. First, flexibility may reduce a number of costs, including network reinforcement costs, capital costs of building generating capacity, and the cost per unit of energy produced, where flexibility allows for increased capacity utilisation. Flexibility may also have an impact on greenhouse gas emissions. For example, improved utilisation of generation assets through flexibility may reduce greenhouse gas emissions per unit of energy produced. Alternatively, if the flexible service produces high levels of greenhouse gases, then it may only be of value if used infrequently. The greenhouse gas implications of gas-based flexibility services will depend, in particular, on the carbon intensity of the gas, which may vary, with future gas networks potentially carrying biomethane or low-carbon hydrogen.

The quantification of different types of flexibility and their value can involve a number of different metrics. Flexibility measures for gas networks may include the capacity of energy storage available, the response characteristics of that storage and the gas stored (linepack) in operating pipes which varies with pressure [8, 18-20]. The value of that flexibility may be measured through other metrics, such as the Value of Lost Load (VoLL), through the financial indicators in the gas market such as gas storage valuation methods, value in gas supply contracts and in the whole
system modelling of energy system technoeconomics [21-24].

1.2. AIM AND SCOPE
The aim of this white paper is to examine the evidence on the flexibility value that gases and gas networks can provide to support the future energy system. To constrain the scope of the analysis within this broad research question a number of scoping points used to frame the white paper are discussed below.

The white paper focuses on the value of gas-based flexibility options, across gas networks, gas end-use and gas as a fuel for electricity generation. The context of broader flexibility options are also examined for context and comparison, though these other flexibility options are not the central subject of the analysis.

An important aspect of the question of flexibility value in gas networks is in the avoided cost of replicating that flexibility in the electricity system, should the gas network be retired. The white paper therefore reviews available whole systems analyses that examine future energy infrastructure with varying reliance on gas networks. This includes the considerations emerging from the necessary transition away from natural gas to low carbon gas vectors such as hydrogen, and hybridisation of energy infrastructures in end uses such as domestic heat or power generation.

The definition of ‘value’ in the guiding research question above will include both monetary value and value in terms of avoided greenhouse gas emissions. The economic value of gas networks does not necessarily have a direct market, and is typically remunerated on an energy basis, not for its capacity, as is the case in some electricity markets. The impact of flexibility provision on greenhouse gas emissions is not commonly discussed in the literature, and not often considered a ‘value’. The implications of this are also discussed. The scope of the evaluation will include the full life cycle of the fuel, including upstream supply chains and end-use.

The methodologies used to estimate the value of flexibility are also examined. A range of approaches to estimating flexibility are used, and lead to significant variation in estimates, disagreement in outcomes and difficulties in drawing comparisons. Methods to model integrated gas and electricity systems are relatively nascent, and the impact of this on the evidence base, and the scope for future research, are also discussed.

The geographical context of studies examining flexibility options is also an important consideration. This includes geographies with predominantly heating energy demand, and geographies with predominantly cooling energy demands where these have been sufficiently studied. The value of flexibility options is highly dependent on the inherent structure of the existing energy system, including factors such as penetration of variable renewable electricity technologies, the extent of natural gas networks, and the daily and seasonal variations in energy demand. These all vary significantly with spatial location and the impacts on flexibility value are discussed.

The geopolitical security of gas supply is a specific aspect of global gas markets often studied [25, 26]. The interconnected pipelines and liquified natural gas (LNG) trading discussed in this report are central to that debate. However, this report does not investigate this complex area of the gas market, treating it as a separate issue to the flexibility debate.
1.3. METHODOLOGY
This white paper uses an adapted methodology created by the Technology and Policy Assessment (TPA) group, part of the UK Energy Research Centre (UKERC) and refined by the SGi for its White Paper Series. The methodology uses systematic and well-defined search procedures to document the evidence review, providing clarity, transparency, replicability and robustness to the analysis. An external expert advisory panel was appointed with a broad range of perspectives to consult on the initial framing and specification of the review procedure, as well as providing additional comments on the emerging analysis. The research outputs have been reviewed by the expert panel prior to publication. The assessment process carried out is presented in Figure 2.

Note on unit axes: Y axes in figures presented in this report are typically given in their published units. A secondary y axis is added to provide a Wh conversion where this is helpful. Conversion values taken from [28].

1.4. STRUCTURE
The rest of the white paper is structured as follows:

- Section 2 presents the definitions and concepts relevant to the discussion of flexibility value in energy systems;
- Section 3 presents the state of evidence for current gas networks flexibility;
- Section 4 presents the evidence on future gas network flexibility, focusing on the likely changes to gas networks and the implications for flexibility;
- Section 5 examines the case study of the Brazilian energy system;
- Section 6 presents the findings, conclusions, policy implications and future research priorities.

**FIGURE 2**
Diagram of the systematic review methodology
Source: Adapted from [27]
2. Definitions and concepts

Gas networks deliver energy flexibly over different timescales and locations. This flexibility stems from a number of characteristics of those networks and the gas they carry. Describing and measuring this flexibility, and its value, requires an understanding of those characteristics, and the relevant definitions and concepts. This section examines these issues, first exploring the definitions, concepts, metrics and methods associated with examining and measuring flexibility and its value, then describing the structure of gas networks and their function in delivering flexibility.

2.1. Definition of flexibility and value

There are a number of different ways in which energy flexibility can be defined. Some published examples include:

- “... modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price) to provide a service within the energy system.” – Ofgem [29];
- “... the ability of the system to deal with uncertainty and variability in the network, while keeping an acceptable level of reliability, from time scales of seconds to hours.” [30];
- “Generation flexibility refers to the extent to which power technologies can respond to the variability in the residual load on different timescales” [31];
- “the capacity to use energy in different locations, or at different times of day or year (i.e. through storage or by changing the timing of activity) to switch fuels, to smooth or create peaks in demand, to re-arrange destinations and journeys in ways that reduce energy demand and/or congestion” [32].

While much of the research on flexibility focuses on electricity systems, the aspects of flexibility definition apply across other energy infrastructures like gas networks or heat networks and the benefit of combining them to improve flexibility is increasingly examined [7, 33-36].

The central interest of this white paper is not simply the flexibility that gas can provide but the value that flexibility represents. “Value” has a number of potential definitions in this context. Studies of gas networks’ contribution to value include:

- Evidence that examines value of gas flexibility through gas prices and contracts [37-40]; and
- Studies that examine the whole system cost implications of flexible gas [41-45].

Another aspect of value in this context that is not often considered is the impact of flexibility on greenhouse gas (GHG) emissions. The emissions of GHGs can be affected by flexibility in a number of ways including:

- The ability of flexibility to reduce curtailment of renewable electricity generation;
- The ability to improve energy systems’ efficiency and;
- The energy and subsequent GHG emissions associated with operating flexibility assets such as gas storage or compression equipment
Given these aspects of both flexibility and value this white paper uses the following definition.

**GAS NETWORK FLEXIBILITY VALUE IS DEFINED AS ITS CAPACITY TO RESPOND TO CHANGING ENERGY SUPPLY AND DEMAND OVER TIME AND SPATIAL SCALES AND THE VALUE OF THAT IN TERMS OF ECONOMIC OR OTHER COST**

### 2.1.1. **FLEXIBILITY OVER TIME SCALES**

Simplistically, two main timescales are typically examined in the analytical literature:

- Daily flexibility (aka intraday, overnight or short term); and
- Seasonal flexibility (aka interseasonal or long term).

Variation in energy demand over timescales arises due to ‘time dependence of social practices’ meaning that some activities, such as heating the house, washing clothes or cooking a meal, are done at a similar time of day by a large proportion of the population [46].

Daily flexibility is the flexibility to meet daily demand as it fluctuates between higher demand in the evening (or also morning in the winter), when heating, lights and appliances are often on, and lower demand overnight or during the day, when electricity and gas powered appliances are off and occupants are either asleep or away from home.

Seasonal flexibility is needed largely as a result of the seasonal changes in weather, ambient temperature and hours of daylight. In temperate climates, winter weather and daylight increase the use of heating appliances and lighting, increasing energy demand. In the summer, these demands are dramatically reduced as temperatures and daylight hours increase. In warmer climates the summer might see increased energy demand due to cooling energy demand through air conditioning units and through increased domestic energy demand due to increased hours indoors [47].

Some studies also reference other timescales, including instantaneous flexibility for peak shaving and medium time scales between daily and seasonal [48, 49]. However, we maintain the simple classification outlined above which is in line with common usage in the literature.

### 2.1.2. **FLEXIBILITY OVER SPATIAL SCALES**

Flexibility in energy delivery also has a spatial dimension. Examples of this might include the upgrading of gas transmission pipelines to provide multidirectional compressor stations to improve the network’s ability to meet dynamics in spatial gas demand [7, 50]. This also includes the relative efficiency with which these infrastructures operate. The literature does not often explicitly characterise this as ‘spatial flexibility’ but the evidence that includes interconnection, LNG markets and network upgrades often implicitly captures this form of flexibility.

### 2.1.3. **FLEXIBILITY MEASURES**

Flexibility of an energy system can be measured in a number of ways, and there is a need for a range of measures or metrics to fully characterise it [18].

The mix of energy generation and energy carriers, including the mixture between baseload, intermediate and flexible peak load generation has an impact on the flexibility of the energy system [18]. Increasing the share of flexible peak-load
generation increases the flexibility, while systems with more baseload generation may be less flexible.

**Measurement of storage capacity**, whether gas storage through linepack and surface or geological storage, or electricity storage options, including batteries, is another indicator of the flexibility of the system [8]. This might be the total recoverable energy stored in a gas storage asset, or the ‘swing’ in gas network linepack (the inverse of load factor and calculated as the peak volume sold over the average volume sold, as a percentage [19]).

The **response characteristics** of a flexibility asset provide another measurable dimension to flexibility. These include:

- Ramp magnitude (the maximum change in power output from a flexible asset);
- Ramp frequency (the rate at which an asset moves to maximum output); and
- Response time (the speed at which an asset can respond to a demand signal) [18, 20].

Other metrics of relevance include security of supply indicators such as the ability of the system to meet demand in case of interruption (so called N-1 in electricity systems), the Supply Standard (ability to meet peak demand in a 1 in 20 winter), or diversity metrics which show supply source or import diversity. These are not discussed further in this report.

**2.1.4. TYPES OF FLEXIBILITY VALUE**

Metrics for flexibility value are similarly diverse.

The **Summer-Winter Spread** is the difference in gas price between summer and winter [40]. This can be examined through the comparison of the historic spot price at chosen points in calendar, or by examining the difference between the spot price and a gas futures price. A large spread between summer and winter prices indicates that seasonal variation in demand has become challenging to meet, while a smaller spread indicates that the system can deliver that seasonal flexibility at relatively low cost.

**Gas contracts** can provide a proxy for flexibility value. Interruptible supply contracts, for example, give large gas consumers a discount on gas delivered relative to standard gas supply contracts. In exchange, suppliers have the right to interrupt supply for a finite number of days over the life of the contract. This is in effect a demand side response contract, allowing suppliers to manage supply during high demand periods. The discount against standard contracts can be used as a proxy for their inherent flexibility value [21, 22].

The **Value of Lost Load (VoLL)** is a common metric in energy systems and represents ‘the value that gas users attribute to security of gas supply and [...] could be used to provide a price signal about the adequate level of security of supply’ [23, 51].

**Storage valuation** methods are often used as a way to understand storage asset values and set prices for storage contracts [22, 52, 53]. The traditional intrinsic asset valuation methods rely on fixed models of gas futures price structure. Extrinsic valuation methods use dynamic price models to analyse the differences between immediate prices and future prices, subsequently attaching greater weight to the time value of stored gas and storage assets with the highest injection and withdrawal rates [22]. Both methods can be interpreted as aspects of the flexibility value provided by energy storage assets.

Finally, **energy models**, particularly whole system models with integrated gas and electricity modules, can be used to uncover flexibility value of gas networks...
[41]. By comparing scenarios that maintain differing levels of gas network utilisation and examining any difference in whole system costs, it is possible to infer a value that gas networks and their inherent flexibility characteristics provide.

2.2. FORM AND FLEXIBILITY: THE STRUCTURE OF FLEXIBLE GAS NETWORKS

The flexibility provided by gas networks stems from a number of important inherent characteristics of gases and the technologies and techniques that constitute the networks carrying gas. The gas network and its possible future forms were examined in the third white paper of the SGi White Paper Series [10]. This includes descriptions of some of these flexibility issues. The key aspects of flexibility provision in gas networks are described below.

2.2.1. THE CHARACTERISTICS OF GAS ENERGY CARRIERS

Natural gas, and other low carbon gases such as biomethane and hydrogen, are well suited to provide flexibility for several key reasons. First gas is inherently storable, with studies of gas flexibility often pointing out this storability quality in the context of electricity storage, which by comparison appears significantly more difficult and more expensive [2, 4, 5, 10, 54, 55]. Gas can be stored in a geological storage facility, surface storage tank or in the high-pressure pipes used in the gas transmission system and some parts of the gas distribution system, known as linepack (see below).

Natural gas is relatively energy dense, particularly when liquified [56]. Figure 3 presents a number of fuels compared by mass density (x axis) and volume density (y axis), showing that while hydrogen is relatively energy dense by weight, it is significantly less energy dense than natural gas by volume. This is an inherent factor in the flexibility characteristics of gas and its relatively low cost storability [10]. However, if future gas networks reduce emissions by transitioning to either biomethane or hydrogen, then the energy carried in those same networks would be reduced. Hydrogen is significantly less energy-dense than natural gas, and this is likely to have an impact on the energy stored in a given network as linepack, or in the space and cost required to develop underground hydrogen storage relative to the current geological storage of natural gas. These are important considerations in the

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**FIGURE 3**

Energy density comparison of several fuels
Source: Adapted from [57]
system planning, operation and costs of decarbonising gas networks and the coordination of future electricity and gas infrastructures.

2.2.2. GAS PRODUCTION
Gas production can also play an important role in the flexibility of primary energy supply, though it is often constrained by geological and economic factors such as technical limitations of varying the output from gas fields. In the United States, for example, the value of natural gas storage has decreased over recent years, in part as a response to the increasing levels of domestic shale gas production [22]. Countries such as Russia, Norway and Qatar have also historically been able to ramp production to respond to their export markets, providing the gas to importers, who often have less flexibility in their domestic production, such as the UK.

Hydrogen may play a more significant role in the flexible supply of gas in the future. However, the cost of hydrogen production is likely to be relatively high, and excess capacity is not likely to be built, making it difficult for hydrogen production to play a significant flexibility role [4, 5]. Biomethane production is similarly constrained in its ability to ramp in order to meet flexibility needs, though constraints in primary biomass availability may also constrain biomethane for gas networks [58].

2.2.3. GAS STORAGE
Gas storage is another route to provide flexibility in gas networks. The inherent energy density and compressibility of gas energy means that storing gas through some form of storage facility is an economically viable approach, even for seasonal storage requirements. Storage of gas can be in tanks, such as surface tanks (gas bullets), traditional gasholder/gasometers or in geological storage facilities, where geological formations such as salt caverns or depleted hydrocarbon reservoirs are filled with compressed natural gas [59].

Surface storage technologies are traditionally used to provide short-term, localised storage requirements, and in countries such as the UK, have largely been replaced by linepack [49]. Geological storage is more typically used for longer-term flexibility requirements, while surface storage is used for daily storage requirements. A more detailed examination of gas storage systems and their relationship to the wider energy system can be found in Qadrdan et al (2020) [49].

Valuing storage flexibility can be achieved through methods such as rolling intrinsic or extrinsic storage valuation, or through modelling of storage scenarios [22, 52].

2.2.4. LINEPACK
Where gases such as natural gas or hydrogen are carried in high pressure pipes, the energy in those pipes can be managed by strategically increasing and decreasing pressure in order to provide flexible energy supply for daily demand variability [8, 10, 42, 49]. This type of flexibility is referred to as linepack, linepack range, linepack flexibility, or swing, and is measured as the difference between lowest and highest pressures in the network over a day [8]. In regions where gas is used to meet high heating loads, pressure is increased during the night, and reduced in higher demand periods throughout the day [8, 10, 49] (Figure 4). The increase of overnight pressure in local gas networks means there is more energy physically closer to end-users in preparation for the large increase in gas demand in the morning.

The value of this type of storage can be estimated by comparing the value of gas as impacted over this daily schedule, though the nature of natural gas
contracts and the lack of a conventional spot price market makes this difficult. Another method is to model the gas network and estimate the value of the network under varying linepack scenarios [42, 60-62].

If hydrogen were to be transported in gas networks in the future, linepack flexibility could also be utilised. However, the difference in volumetric energy density means that less energy is available through linepack in a hydrogen network [54, 57] (Figure 3). The linepack capacity of a hydrogen network may be over four times smaller than the existing natural gas network for the equivalent pipeline. Additional pipeline reinforcement or higher operating pressures may be able to increase hydrogen network linepack range, though at an additional cost [54]. Hydrogen networks may also be smaller and more fragmented, further reducing the potential flexibility provided by linepack [10]. These factors compound the limitations on linepack flexibility for hydrogen networks, and several studies examining the opportunities for hydrogen networks include a significant role for hydrogen storage to meet flexibility requirements [3-5, 63].

2.2.5. LIQUEFIED NATURAL GAS (LNG)

LNG plays two roles in the delivery of flexible energy supply. LNG peak shaving plants can provide flexibility to gas networks by liquefying natural gas at periods of low demand and re-gasifying that gas at times of high demand [64]. This is a strategy found in North America, where LNG peaking facilities were particularly active in the 1970s [64]. The UK LNG market began with LNG peak shaving, though import terminals are now more common [65]. LNG import terminals receive LNG, transported by ship, and then re-gasify the LNG for injection into the domestic network [49]. This provides flexibility as it allows for the delivery and injection of gas on a schedule that complements the demand profile, in a similar way to the role of interconnection (see below). Liquefied hydrogen flexibility, particularly the peaking plant strategy, is a potential option for future hydrogen networks. However, it is unclear whether this will be an attractive strategy economically and an international market for tradeable hydrogen is likely to be some way off [2].

The value of LNG has been explored in the academic literature, where economic concepts such as the value of marginal product, and the price impacts of capital cost decisions in LNG investment are explored [66, 67].

FIGURE 4
UK National Transmission System Linepack capacity in energy stored, on an hourly basis for one day (on 1 March 2018)
Source: [13]
2.2.6. INTERCONNECTION

Interconnection is the connection of domestic gas networks to networks of neighbouring countries with gas export capacity. Interconnection is a strategy available to both gas and electricity networks. Flexibility is provided through the purchase of gas on a seasonal profile that matches expected variation in demand. Interconnectors also provide flexibility through access to diverse supply routes or bidirectional flows, and their capacity, which if insufficient will limit the interconnector’s flexibility role.

It is unlikely that there will be a tradeable market in networked hydrogen for some time, making interconnection of future low carbon gas networks challenging. Hydrogen production from methane reforming technologies will have the benefit of the existing natural gas network for primary energy, including interconnection. However, as mentioned above, these hydrogen production plants are unlikely to operate in a flexible way, and the management of demand and flexibility for hydrogen networks will largely take place downstream from the production plant [5]. Maps of European and United States gas interconnection can be seen at [68] and [69].

The value of gas interconnectors can be inferred from, for instance, the auctions for interconnection capacity charges as defined by the European Interconnection Document (EID) and published by some Transmission authorities [70]. The role of interconnectors is also captured in some whole system models and can be used to test the impact of interconnection on network flexibility [7].

2.2.7. FUTURE FLEXIBLE STRUCTURES IN GAS NETWORKS

A number of emerging flexibility strategies might play a role in the future decarbonised energy system. Power to gas (PtG) is the conversion of electricity to gas, typically either hydrogen or methane [50]. It has been proposed as a flexibility measure to address renewable generation curtailment and improve the utilisation of renewable assets. This could become an even more useful approach if hydrogen networks replace natural gas, and emerging evidence on the safety of blending hydrogen in the gas grid might support the wider use of PtG with hydrogen injection to the existing grid [71]. However, there are economic challenges to this approach currently, including the cost of electrolysis technologies [72-74].

Gas/electricity hybridisation is a potential approach to improve flexibility of energy systems in the future and can play a role at various scales within the energy network. At the domestic and commercial consumer scale gas hybrid heat pumps can be used to provide heat to domestic and commercial consumers [16, 41, 75]. An electric heat pump operates in the majority of conditions to provide low carbon heat. At periods of extreme low external temperature, when electric heat pump is least efficient and most burdensome on peak electricity demand the appliance can switch to a gas fired mode, reducing the burden on peak electricity demand, while only having a minimal impact on emissions through very low use of natural gas. This strategy is also possible at district level, where hybrid systems can be used to provide heat for district heating networks [41]. At a larger scale, large scale hydrogen production can be routed to either gas networks or power generation, with power generation potentially able to take varying blends of natural gas and hydrogen. This provides hydrogen production assets with flexible hydrogen markets, ensuring maximum utilisation while minimising the need for storage [76].
3. Current gas network flexibility

3.1. Quantifying current gas network flexibility

Current natural gas networks across the globe employ a range of flexibility capacities that have been developed in response to individual countries’ or regions’ energy mix and market structure amongst other drivers. A few key metrics and illustrations are presented below, giving a picture of the flexibility capacity of gas networks internationally.

3.1.1. Linepack flexibility

The UK is one of the more studied gas networks in terms of flexibility, and a number of studies have included assessments of the linepack flexibility capacity [8, 36, 42, 77-79]. Wilson and Rowley [8] analyse the UK use of linepack flexibility from 2013 to 2018, examining both the national transmission system and the local transmission system gas networks. The maximum daily swing over that period was 337 GWh in the local gas network and 427 GWh in the National Transmission System [8]. This can be compared to UK pumped electricity storage over the same period, which had a maximum daily discharge of 18 GWh, demonstrating the challenge of replacing linepack with any other form of responsive energy storage [8]. Total gas demand in 2018, including domestic demand and power generation, was 881 TWh [80].

Figure 5, which is presented by Wilson and Rowley [8], illustrates this linepack flexibility using data for the UK local gas network in December 2017.

Gas linepack models exist for other regions including the United States [81] and Europe [82], though there has been less analysis on the quantity of flexible gas storage provided by linepack in these regions.

3.1.2. Gas storage

Global utilisation of gas storage varies considerably across countries and has been a changing picture in recent years. Underground natural gas storage in EU countries and the UK is presented in Figure 6 by underground storage type. Figure 7 presents natural gas storage capacity in the UK and Europe against annual demand. The UK has relatively small storage capacity relative to annual gas demand. This is a trend that has increased as storage facilities in the UK have closed [83], including the UK’s only...
seasonal non-LNG storage facility (the Rough storage facility, which effectively closed as a store in early 2018).

Generally, European countries hold more gas in storage as a proportion of demand than that seen in the UK. However, storage closure is a trend also seen in Europe, with over 70 TWh of gas storage closed in North West Europe between 2013 and 2017 (Figure 8)[39].

**FIGURE 6**
Technical working gas volume of underground gas storage facilities per country by underground storage type
Source: [84]

**FIGURE 7**
Natural gas storage capacity in the UK and European countries presented against annual demand in 2018
Source: [85]
Note: Bubble size represents the present storage capacity expressed as a percentage of annual demand

**FIGURE 8**
Cumulative gas storage closures in North-western Europe (2013 to 2017)
Source: [39]
The United States has significant quantities of natural gas storage in a number of states across the country (Figure 9). The United States maximum designed natural gas storage capacity in 2018 was 4.7 trillion cubic feet (1,400 TWh). To put this in context, the United States gas demand in 2019 was over 31 trillion cubic feet (9,500 TWh) [86]. Storage in the United States is therefore approximately 15% of annual demand, and has also been in decline, with increasing gas production driving down the value of storage [87]. This puts the United States gas storage provision somewhere between the UK (~7%) and the general trend in European countries (~30%) (Figure 7).

### 3.1.3. INTERCONNECTION

The UK gas network imports natural gas through three pipelines from Norway, and can import and export across pipelines connecting to Belgium and the Netherlands [80]. Figure 10 presents imports of natural gas to the UK from 2016 to 2019, illustrating the significant imports of gas to the UK network through the Norwegian pipelines in particular. It also demonstrates the participation of LNG imports into the seasonal demand.
market along with pipeline imports, providing supply flexibility to meet the significant seasonal swing in demand. The profile of imports reflects the seasonal fluctuations in total demand (Figure 11), highlighting the role of imports in supporting flexible seasonal gas supply. In the first quarter of 2019 total gas demand in the UK was over 250 TWh while imports from Norway were over 100 TWh [80].

Europe is interconnected to gas supply from Russia, the Middle East and North Africa in addition to the North Sea gas from the UK and Norway [88, 89]. Figure 12 presents production and contracted imports through interconnected pipelines and LNG, with the estimated additional supply required to meet predicted demand in light of forecast reductions in domestic production to 2025. This highlights the significant proportion of imports relied upon in the EU to meet natural gas demand, and the issues created by continuing decline in production from the North Sea and reduced production in the Groningen field in the Netherlands [39].

The United States imports natural gas through pipeline interconnections from Canada, with a small additional contribution from Mexico, though the United States is a net exporter to Mexico. Canadian net imports (Canadian pipeline imports minus Canadian pipeline exports) are presented in Figure 13. Pipeline net imports through interconnectors lie between 500 and 800 TWh per year, or between 5% and 8% of annual consumption, which was 9450 TWh 2018 [86, 90].

3.1.4. LNG IMPORTS
In the UK, LNG imports make up a growing but smaller share of gas imports (Figure 10) [80]. LNG imports reached 200 TWh in 2019, making up 39% of total imports, an increase from 15% in 2018. This highlights the growing importance
of LNG in UK gas supply over recent years. Qatar LNG makes up almost half of LNG imports to the UK, with the balance received from the United States, Russia, Angola, Cameroon and the Netherlands [80].

LNG imports to Europe were approximately 1,100 TWh in 2019, against a total consumption in 2019 of approximately 5,350 TWh [91, 92]. Qatar, Russia and the United States make up the majority of LNG imports to Europe (Figure 14).

United States LNG imports have been falling since 2015, with the majority of LNG coming from Trinidad and Tobago (Figure 15). However, as a proportion of total demand, LNG imports are very small at ~0.1%, and their contribution to flexibility is localised. The increase in domestic gas production and the transition to a net exporter is now more characteristic of the United States gas market. However, one illustrative example of LNG impact on flexibility can be seen in the New England gas market, where increased LNG import capacity has mitigated the lack of seasonal storage and reduced price volatility in winter relative to previous years [93].
3.2. VALUE OF GAS NETWORK FLEXIBILITY

The following section examines metrics and proxies of flexibility value in the literature for gas networks in Great Britain, Europe and the United States. This analysis focuses on the common methods, including:

- Market indicators such as the impact of flexibility on summer-winter price spreads; and
- Theoretical models of gas networks and markets.

3.2.1. SUMMER-WINTER PRICE SPREADS AND SEASONAL FLEXIBILITY

Summer-winter spreads in Great Britain are presented in Figure 16 [40]. These are calculated as the difference between the average National Balancing Point (NBP) contract price of quarters two and three and the contract price of the following quarter one in a given year. The most significant trend in the years since 2005 is the reduction in the summer-winter spread, indicating the gas system has experienced a reduction in cost associated with meeting the seasonal swings in gas demand. Over this same period gas storage capacity, which can be used to meet seasonal demand swings, was in decline (see 3.1.2). A number of factors affect both the demand swing over the year and gas supply, which the summer-winter spread is a product of. However, a significant factor in this trend is the increasing quantity of pipeline and LNG imports in the UK, particularly given the ability of LNG to respond in a similar manner to storage in terms of its ability to operate flexibly and in response to price [40]. There has been a slight increase in the summer-winter spread in recent years, though this has not been sufficient to reverse the general trend over the last 15 years.

**FIGURE 16**

Gas summer-winter spreads at the National Balancing Point (NBP)
Source: [40]
The trend in decline of the summer-winter price spread is also evident in Europe. Figure 17 shows the spread between summer and winter gas prices settled at the Title Transfer Facility (TTF) virtual trading point in the Netherlands. This shows the significant reduction in summer-winter spread for European traded gas from over €5 per MWh in 2008 to less than €1 per MWh in 2018 (€1 was equivalent to £0.91 in 2019) (Table 1). This change in the summer winter spread is thought to have driven the reductions in storage capacities in North West Europe since 2013. Similar trends of increasing gas imports, particularly through LNG are likely the driver of the summer-winter price change [39]. In essence, the seasonal flexibility of supply offered by LNG and by pipeline supplies has created greater competition for seasonal gas storage facilities and created a downward trend on the price spread between summer and winter.

In the United States, the average spread in 2018 was 20 cents per million BTU (0.05 pence/kWh), while the 2016 average was 69 cents per million BTU (0.18 pence/kWh) [38]. This narrower difference has reduced the economic incentive to invest capital expenditures in increasing natural gas storage infrastructure [87].

Figure 18 presents the difference between the spot price and the January delivery futures price in the United States, presenting another form of summer winter spread analysis. The second y axis shows the storage volume at the beginning of the heating season. Spreads in the United States are low, having reduced significantly in the last two years.

### 3.2.2. Storage Valuation

The literature contains several references to methods for estimating the value of gas storage in order to help set storage prices [14, 22, 52, 53, 94]. These include:
Basket of spreads method;
• Intrinsic valuation;
• Rolling intrinsic valuation;
• Extrinsic valuation; and
• Forward gas price modelling.

However, results of these methods for country level storage or gas markets are not typically presented in the evidence base, probably due to the commercially sensitive nature of these estimates [37].

In line with the trend in storage closures, several studies refer to the decreasing economic viability of storage projects [37, 39, 40, 87].

To highlight this challenging value proposition for seasonal gas storage, a number of European examples are presented in Figure 19. This shows the stated storage price and the transmission fee compared to the summer winter price spread in that year. These examples suggest that two countries operate storage facilities at a ‘break-even’ price while four others were likely to make an economic loss [37].

3.2.3. NETWORK SERVICE CHARGES

In an example of daily flexibility services and their value, the European Balancing Network Code makes provision for Transmission System Operators (TSO) to provide Linepack Flexibility Services to ‘shippers’ who contract to transport gas via the TSOS network [95]. The Netherlands based Gasunie provides a Linepack Flexibility Service under this code to its shippers at a tariff of 0.4% of the natural gas price, indicating a metric for the value [96].

3.2.4. VALUE OF LOST LOAD (VOLL)

This metric, more common in electricity security of supply analysis, is less commonly expressed for gas consumers. An analysis of UK Value of Lost Load (VoLL) as part of a regulatory review of gas supply security examined the VoLL for Domestic, Small and Medium Enterprises (SME) and Industrial Consumers [23, 97]. The study used stated preference techniques to discover the VoLL from consumer survey responses, looking at both Willingness to Accept and Willingness to Pay approaches. Though it was contested by industrial respondents to consultation a VoLL of £14/therm was agreed for domestic consumers [97].

While this metric does expose interesting aspects of flexibility value, it focuses on security of supply. This can be viewed as distinct from the flexibility and economics associated with meeting variable demand.
3.2.5. ENERGY SYSTEM MODELS AND ESTIMATES OF GAS FLEXIBILITY VALUE
An approach to examining the value of gas network flexibility is through theoretical modelling of gas systems and markets. A number of these examine daily flexibility services, which are generally considered easier as a technical and economic challenge given the smaller storage requirement and the more frequent opportunities for utilisation throughout the year providing easier value capture.

Midthun et al (2007) [62] value the linepack as a natural gas storage facility, taking the perspective of a natural gas producer. They optimise the value of the gas sales for the producer both with and without linepack and quantify the size of a pipeline’s possible linepack. The study involves comparing both stochastic and deterministic modelling approaches and models the market over 60-day periods. The study finds the use of linepack to maximise achieved price results in profit increase of approximately 14%.

A modelling assessment of the gas and electricity systems in Germany examined the value of linepack storage as a flexibility mechanism to deliver gas to a gas fired power station. This involved ‘soft linked’ gas and electricity models, which were used to identify any advantages to linepack storage, particularly over periods of particular price volatility. The study found that linepack may allow arbitrage between inflexible take or pay contracts and flexible power generation, providing a 34% increase in value [82].

Chaudry et al (2008) [61] present an integrated gas and electricity model for the UK and test the impact of outages at a key receiving gas terminal on system operation. The study also tested the additional outage of the Rough gas storage facility. The study found that monthly system cost increased in the order of 50% with Bacton closed due to costs associated with load shedding. However, without the Rough storage facility, costs increased in the order of 150%.

3.3. GHG EMISSIONS ASSOCIATED WITH FLEXIBILITY IN THE CURRENT GAS NETWORK
Gas flexibility can help to reduce GHG emissions by providing flexible backup to increase penetration of intermittent renewable energy technologies [98-100]. However, flexibility often has its own energy and GHG burden, which potentially erodes the emission reductions of the network. This section examines the GHG implications of flexibility, first by examining the role of gas in supporting electricity networks and then in the role of gas networks in serving end-use demand directly - largely in domestic and commercial space heating.

3.3.1. GHG EMISSIONS OF FLEXIBLE GAS POWER GENERATION IN SUPPORT OF ELECTRICITY NETWORKS
Gas power generation is often highlighted in the role of providing flexibility to the electricity system due to its responsiveness, and GHG emission relative to other thermal generation options. However, in comparison to the intermittent and less flexible power generations options that natural gas is expected to support, gas has relatively high GHG intensity. Figure 20 illustrates this issue, showing gas power generation options in the middle of the GHG intensity ranking, with other thermal generation typically more GHG intensive, and the intermittent or baseload generation technologies typically less GHG intensive. Dutch and Irish electricity imports also have higher emissions than gas because of the GHG intensity of the electric mix in these countries (95% from coal and gas) while French imports, dominated by nuclear power generation, are relatively low emissions [101, 102].
To meet variation in electricity demand, the UK uses these supply options in combination with pumped storage and battery storage.

Natural gas power generation as a flexibility mechanism is complemented by electricity storage options, including pumped hydroelectric electricity storage and battery storage. These also have a GHG implication based on the production or building of these technologies, the energy used to operate them and the charging cycle frequency or utilisation. Figure 21 presents gas power generation, pumped storage and battery storage in terms of current installed capacity and GHG emissions. The UK currently has significantly more installed capacity of gas power generation, but the emissions are over double that of pumped storage or battery storage (Figure 21). Pumped storage and batteries could reduce emissions from electricity flexibility, though pumped storage is limited by appropriate sites in the UK and battery storage is currently limited by cost [109]. Figure 21 illustrates the important role that natural gas currently makes to the flexibility of the UK energy system, despite its relatively high emissions. This importance is also reflected in UK focused whole system energy modelling (Section 3.2.5).

Battery storage is a recent addition to the electric grid and has the most potential for displacing gas in meeting electricity peak demand due to investor interest [110]. Other low carbon flexibility options may be able support the electricity network in the future, such as CCS on flexible gas power generation,
flexible nuclear generation, or low carbon hydrogen or biomethane power generation, though these options are not currently deployed. There is therefore a future challenge to maintain flexibility in order to support the deployment of intermittent renewable energy technologies and increasing demand for electricity, while minimising the GHG impact of that flexibility option in order to meet challenging decarbonisation targets.

3.3.2. GHG EMISSIONS OF GAS NETWORK FLEXIBILITY

Operating gas networks flexibly has an energy requirement and an associated GHG impact. The gas grid typically uses gas as fuel to run ancillary equipment and processes such as compressor stations, which are used to charge linepack in network pipes or underground gas storage facilities. Gas used by the grid can be split into three: the national transmission system and local distribution’s own use of gas, gas storage facilities own use of gas and LNG terminals (Figure 22). The grid’s own use has historically been the biggest user of gas but in recent years, LNG terminals have become the largest consumer. This change is driven by a number of factors, including the increase in LNG imports to the UK, the decrease in gas consumption overall and the increase in electrification of ancillary equipment such as compressors and pumps. Comparing the peaks and troughs of gas consumption by the whole grid, LNG terminals do not have a distinctive seasonal variation, though they can be used in winter to help meet peak demand. The grid’s own use of gas energy peaks in winter, driven by the energy needs associated with the compression needed to move increasing volumes of gas during winter peak demand. Storage facilities’ own use of gas peaks in summer, driven by summer charging of seasonal stores in preparation for the winter season, where this gas will be discharged to the network. This activity ends in 2017 in Figure 22, reflecting the closure of the Rough storage facility in the UK.

The GHG impacts of gas network operation also follow a seasonal pattern related to ancillary equipment and processes necessary to deliver energy to meet seasonal variation in demand. The marginal increase in GHG emissions associated with seasonal flexibility activities such as compressor activity can give an indication of the emissions resulting specifically from meeting those seasonal demands. Figure 23 presents the difference in emissions and energy

**FIGURE 22**

Historic gas consumption (GWh) by the gas grid per month
Source: [117]
delivered to meet this own-use energy demand between winter and summer. First, the emissions associated with grid flexibility have been decreasing for the grid since 1996 in line with the decrease in gas own use seen in Figure 22. The GHG emissions per kWh energy demand of the grid was 0.92 g CO₂-eq./kWh in 2019, with a five-year and ten-year average of 0.73 g CO₂-eq./kWh and 0.95 g CO₂-eq./kWh. To put this GHG intensity in context, the emissions of burning natural gas are 184 g CO₂-eq./kWh and including efficiencies and supply chain emissions, a kWh of gas boiler heat emits approximately 300 g CO₂-eq./kWh.

Though comprehensive whole system models should capture these emissions within supply chain gas demand, the difference in own use emissions between winter and summer give an idea of the marginal emissions resulting from the large seasonal shifts in energy demand. However, development of consequential life cycle assessment to illustrate the GHG impacts of different flexibility choices could further inform the role of gas networks relative to other flexibility measures [118].

In summary, natural gas provides seasonal flexibility with very little additional GHG emissions. However, if this is burned at end use, as typical in the domestic sector, then life cycle emissions are a challenge, and future decarbonised gases will be required. If this gas is used to support power generation then emissions at the power station can be mitigated through CCS, though again this requires infrastructure and is not currently an option in modern energy systems. This points to the need for fundamental changes in gas networks in order to contribute effectively to future energy systems while meeting decarbonisation goals. It will be important in the future to examine the impact of these changes on the emissions associated with operating gas networks flexibly.

**Figure 23**

GHG emissions per unit flexibility and historic gas consumption

*Source: [117]*

Note: Calculated as the winter demand minus summer demand for Grid own use.
4. Future gas network flexibility

This chapter appraises the flexibility options for future energy systems as they will develop in the future with a focus on the role of gas networks. The analysis will also highlight uncertainties and limitations of the modelling approaches currently employed.

4.1. ASPECTS OF THE FUTURE GAS NETWORK

While flexibility has been a valuable characteristic of gas networks to date, the nature of energy sector decarbonisation increases the need for flexibility. In particular, increasing penetrations of intermittent renewable energy generation and the increased burden on electricity to deliver heat and transport energy are particularly challenging for energy system balancing. By some estimations, as penetrations of intermittent renewables such as wind and solar energy increase beyond a third of electricity generation at a sub-regional scale, further interventions at the supply level will be required not only to meet increased variability of electricity, but also to manage energy demand and increasing coordination between electricity and gas networks [119, 120].

Figure 24 presents daily and seasonal flexibility options and their expected cost reduction between 2015 and 2030. This shows that, particularly for seasonal flexibility requirements in the future, gas network flexibility options such as Combined Cycle Gas Turbines (CCGT) with carbon capture and storage (CCS) and hydrogen geological storage are relatively cost-competitive amongst the scalable options.
4.1.1. CHALLENGES FOR FLEXIBILITY IN THE FUTURE GAS SYSTEM

The challenge for the future gas network is in meeting climate targets. The options to achieve gas network decarbonisation are explored in the third white paper of this SGi White Paper Series [10]. However, the main issues that affect the flexibility provision of gas networks are summarised below.

Gas networks may transition to low carbon gases such as hydrogen or biomethane to reduce their greenhouse gas emissions. This will have an effect on the flexibility options available to gas networks, and the capacity of available storage. First, international trade of these low-carbon gases is likely to develop over time but will not be prevalent at the beginning of any transition to low carbon gas networks [2]. Given that these are aspects of the current natural gas market that have contributed to reducing the cost of meeting seasonal demand variation then this is likely to inflate flexibility costs. In order for gas networks to continue to operate flexibly, gas storage in the form of underground storage, surface tank storage and linepack will be the main flexibility mechanisms available. Studies in the UK that examine the transition to low carbon networks based on hydrogen focus on underground hydrogen storage to meet seasonal demand variation in particular [4, 5, 10].

The lower energy density of hydrogen also increases the challenge, and cost, of matching the flexibility of the current gas network. For example, the linepack available in a hydrogen network might be 25% of the linepack available in the current gas network on an energy basis, a combination of energy density and the operating pressure profile of the hydrogen network [54]. However, the level of linepack flexibility that might be feasible with this reduced amount of linepack is an open research question that warrants investigation.

An estimate by Ozarslan (2012) [122] on underground hydrogen storage suggests that converting the now closed Rough storage facility to operate as a hydrogen storage facility would deliver 42% of the energy storage possible when operating with natural gas [121, 122]. Bulk storage options such as using ammonia as a hydrogen carrier might help reduce costs in the future, particularly for international trade. However, this option is less prevalent in the gas network literature and likely to take longer to reach commercial viability.

Figure 25 presents a comparison of underground storage costs for hydrogen and natural gas. Cheapest estimates of hydrogen storage are equivalent to natural gas underground storage [10, 37]. However, the range of hydrogen underground storage costs includes
more expensive estimates. This range is influenced by a number of factors, including assumptions on storage capacity and storage time, the depth of injection, the operating pressure and the amount of hydrogen injected [10].

The gas network is also likely to fragment, separating not just from the interconnection and LNG markets of other countries, but also within countries, as different regions adopt differing strategies to address climate change targets [4, 5, 63]. This will have an impact on system flexibility, with individual network subsystems requiring flexibility capacity to be entirely self-sufficient. For example, an analysis of the conversion of an urban gas network in the UK to hydrogen proposed seasonal hydrogen storage of approximately 7% of the estimated annual hydrogen demand (Table 2). This is comparable to historic seasonal storage in the UK natural gas grid, though the closure of seasonal gas storage in recent years means that the current UK gas system operates largely on medium range storage [40].

One future option that includes gas networks is the use of hybrid heat pumps. However, where hybridisation strategies lead to a significant reduction in demand, it will be challenging to maintain the operation of networks without significantly increasing the price of gas (hydrogen probably) at peak demand. Studies suggest that this is possible but concerns remain over consumer acceptance of this strategy [41, 75].

One consideration for policy around the development of low carbon gas networks could be to examine the potential support levers to encourage the development of international markets for hydrogen and biomethane. This would reduce the pressure on domestic hydrogen or biomethane storage and perhaps experience the benefits currently enjoyed by the internationally connected natural gas market. The International Energy Agency (IEA) identifies a range of policy priorities in supporting the development of the first international shipping routes for hydrogen. These include:

- Establishing targets and/or long-term policy signals;
- Supporting demand creation;
- Mitigating investment risks;
- Promoting R&D, strategic demonstration projects and knowledge sharing; and
- Harmonising standards, removing barriers [124].

### 4.2. MODELS OF FUTURE GAS NETWORKS AND FLEXIBILITY

Whole system energy models with scenario analysis approaches provide one of the few ways in which to estimate future flexibility and energy system costs. The models which can be used to estimate the flexibility of future natural gas networks at different levels of granularity, include; integrated assessment, energy-economy, power system planning and energy system planning.

Energy systems modelling is classified in top-down (econometric, system-dynamics, computable general equilibrium, and input-output) and bottom-up categories (optimization,

<table>
<thead>
<tr>
<th>TABLE 2</th>
<th>Hydrogen storage in the H21 Leeds City Gate report compared to current and recent UK seasonal natural gas storage</th>
<th>UK seasonal storage</th>
<th>UK in 2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seasonal gas storage</td>
<td>732 GWh</td>
<td>56 TWh</td>
<td>0</td>
</tr>
<tr>
<td>Annual gas demand</td>
<td>9904 GWh</td>
<td>777 TWh</td>
<td>881 TWh</td>
</tr>
<tr>
<td>Proportion</td>
<td>7.4%</td>
<td>7.1%</td>
<td>0%</td>
</tr>
</tbody>
</table>
equilibrium, simulation, and agent-based models), as well as hybrid energy models (integrated, soft-linking, and hard-linking). Specific optimisation models are developed to perform co-planning of power and natural gas networks and are applied at system or local/distribution level [125]. Sector coupling, storage, and demand management options are generally captured in energy systems models, whereas grid operations, natural gas and electricity integration, and transmission investments are captured in power sector models.

Below, applications of energy and power sector modelling are presented for selected international cases of grid developments to appraise gas network flexibility. The analysis uses a scenario-based approach. A scenario represents a possible future development of a system with the purpose of systematically exploring uncertainties based on available knowledge. Scenarios are invaluable decision support tools to shed light on planning of future commodity infrastructures [126]. Especially for an energy system transition compatible with limiting global warming, scenarios have played a role in informing both in policy making [127, 128] and industry decision making [129].

4.2.1. GAS NETWORKS IN GREAT BRITAIN

The future role of gas networks and energy system flexibility in Great Britain has examined the issue in depth over the last decade [4, 5, 7, 10, 33, 35, 54, 55, 130-134]. A significant area of study has been in the conversion of natural gas infrastructure to carry biomethane and hydrogen in order to decarbonise networked gas while maintaining the benefits of gas network flexibility. The important aspects of this research are covered in SGi White Paper 3 [10].

Ameli et al [7] conduct scenario analysis using an integrated gas and electricity model to explore the value of gas network flexibility and flexible gas power generation to support increasing penetration of intermittent renewable power generation in the UK electricity system. The use of multidirectional compressors on the gas transmission, along with integrated operation of both gas and electricity systems was found to reduce operating costs by 30% in the event of an outage of major gas terminal [7].

A development of the same model looked at coupled and decoupled modelling of gas and electricity systems. Coupling (solving gas and electricity demand simultaneously rather than solving electricity first and using gas for power as an input for gas modelling) leads to a 7% reduction in operating costs. Increasing flexibility of the system by increase in gas fired generation flexibility, multidirectional compressors and increased gas imports, removes the benefit of coupling, leading to a 7% reduction in operating costs of both coupled and decoupled [33].

In a third example of the same model Strbac et al [41] provided analysis for the UK Committee on Climate Change for their ‘Hydrogen in a Low Carbon Economy’ report [2]. The supporting work examined the costs and potential of UK energy system scenarios with gas and electricity networks including a hydrogen-focussed scenario, an electricity-focussed scenario and a scenario integrating hydrogen gas networks and the electricity network. A key finding of this report was that system costs are comparable for all scenarios, with hybridisation providing a benefit of approximately 5% against other scenarios in annual system costs while still delivering of decarbonisation goals. The exception to this is the hydrogen dominated scenario for net zero emission, which builds significant quantities of low carbon electricity generation and electrolyser,
incurring associated additional costs. These results are, however, subject to significant uncertainty regarding the development of future costs. An additional finding of this study is the ability of the gas network to carry reducing volumes of gas for peak load operation of hybrid heat pumps while affording the maintenance of gas networks year-round due to the significant increase in gas value at peak load.

A series of studies by Clegg and Mancarella use an integrated gas and electricity model approach to assess various aspects of future gas network operation in Great Britain [19, 35, 36, 73, 77, 135]. These studies highlight the importance of integrating both gas and electricity networks in modelling and assessments of future energy systems and their ability to address the challenging nature of decarbonisation and reliable energy supply. This is particularly driven by the relationship between heat demand and the flexibility capacity of gas networks.

A number of key aspects of gas flexibility are highlighted. First linepack flexibility has a potentially important role in

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**FIGURE 26**

Annual system cost components of hydrogen pathways in different cases

Source: [41]

Note: Figure shows three energy system pathways, each with a 30 million tonnes, a 10 million tonnes and a 0 tonnes residual emissions in 2050 case. In the H2 pathway, the majority of domestic heating will use hydrogen-based gas boilers with zero direct carbon emissions. In the Electric pathway all heating is electrified using a combination of heat pumps and resistive heating. Industrial heat pumps are used for district heating. In the Hybrid pathway a combination of hybrid heat pumps (HHP) and hybrid resistive heating are used to supply heating demands to those on the gas network.
supporting backup generation to meet increased electricity demand for heat pumps. Further, the timescale upon which this is assessed is important, given the peaky nature of this demand on a daily timescale. The use of power to gas technologies to address renewable energy curtailment in the UK is also examined using this integrated modelling framework. A key finding of this analysis is that, based on the assumptions included in the analysis, the UK energy system could see the additional integration of over 35 TWh/year of renewable energy generation, supported by power to gas. The additional low-cost gas produced could reduce the annual costs of the gas grid by 4%.

4.2.2. GAS NETWORKS ACROSS EUROPE

As with the UK, the role for European gas networks has been the subject of increased study in the light of climate targets and the requirement for energy system flexibility. A study by Navigant examined the future role of gas networks across Europe, focussing on the transition from natural gas to hydrogen and biomethane [1]. They examined a 2050 snapshot for two scenarios for comparison, both in line with the commitments under the Paris agreement:

- A “Minimal Gas” scenario, where renewable and low carbon gases are only used in sectors where no alternative was available; and
- An “Optimised Gas” scenario, where renewable and low carbon gases are used to their full potential.

The study found that deep decarbonisation requires significant renewable energy generation, which needs flexible power generation support through either solid biomass or gas plants. The study also concludes that batteries are unrealistic for seasonal storage requirements. High temperature industrial processes were assumed to require gas as primary energy in both scenarios due to challenges in meeting this demand through any other means.

The “optimised gas” scenario uses 1,170 TWh renewable methane and 1,710 TWh of hydrogen per year across the whole energy system. Compared to the “minimal gas” scenario, the use of gas through gas infrastructure saves society €217 billion annually across the energy system by 2050, largely through

![FIGURE 27](image-url)

**FIGURE 27**

Quantities of gas used per sector and resulting energy system cost savings in the “optimised gas” scenario versus the “minimal gas” scenario

Source: [1]
the reduced costs related to providing system flexibility with reduced low carbon and renewable gas. Figure 27 presents the difference between the two scenarios in terms of gas use and system cost in 2050, illustrating the cost saving in €/MWh and the use of low carbon and renewable gases in TWh/year for the four main sectors.

In a review of future gas scenarios in Europe, Cătuță et al (2019) present a number of future demand estimates from a range of scenarios in the current literature [136]. While the report highlights the role of gas in the future to provide flexibility, there are no system level economic estimates. The report found that, based on the studies reviewed, natural gas demand to 2030 was stable or slightly decreasing. However, gas demand changes significantly in the period from 2040 to 2050 in response to climate targets. An important citation supporting that conclusion comes from the European Commission’s “A clean planet for all” report [137]. Figure 28 illustrates this analysis, showing the decreasing role for natural gas, and the increasing share of hydrogen and other low carbon gases with increasing GHG reduction targets.

**Gas in power generation**

Several studies have attempted to project the possible evolutions of the power system in Europe, some of them looking at the integration of 100% renewables in the generation mix. This analysis provides some insight into the potential role of gas in power generation in the future. Highlights from studies are summarised below.

At a high level of renewable penetration, Van den Broek et al (2015) [50] highlighted the need for natural gas to provide short-term reserve and seasonal flexibility. Natural gas fired generators are the cheapest generation options (through gas turbines) and can provide low-carbon electricity (through natural gas combined cycle with CCS (NGCC-CCS) technologies).

Similarly, gas turbines and NGCC-CCS are key technologies delivering the renewable target scenarios, characterised by 40%, 60%, and 80% renewable energy generation [50]. The bulk of energy generation was provided by intermittent renewable energy technologies, nuclear, hydropower, and NGCC-CCS generators. Peaking options such as gas turbines and demand side management (DSM) have low capacity factors (≤5%). As the renewable energy capacity increases, the residual load...
lowers, reducing NGCC-CCS capacity for GTs, because intermittent renewable energy requires a cheap provider of capacity to ensure system adequacy.

Siemonsmeier et al (2018) [138] analysed the role of the hydropower in the Nordic region to provide flexibility to the EU. Although hydropower was deemed suitable to meet flexibility challenges set by the increase of intermittent renewable energy, it appeared a second-best compared to natural gas fired plants, especially in highly decentralised scenarios. However the authors identified the potential for flexibility provision offered by Nordic hydropower in high climate mitigation scenarios.

Gas demand in decarbonisation scenarios
ENTSO-E publishes scenarios of future electricity demand and supply on a regular basis [100] focusing on three main scenarios built on the “Best Estimate” Scenario, which reflects a conservative grid development:

- A National Trends (NT) Scenario, based on draft NECPs and compliant with the EU’s 2030 Climate and Energy Framework (32% renewables, 32.5% energy efficiency) and European Commission (EC) 2050 Long-Term Strategy with an agreed climate target of 80 – 95% CO₂ reduction compared to 1990 levels;
- A Global Ambition (GA) scenario, compliant with the 1.5°C target of the Paris Agreement and focusing on development in centralised generation; and
- A Distributed Energy (DE) scenario, compliant with the 1.5°C target of the Paris Agreement and focusing on a de-centralised approach to the energy transition.

Expected gas demand used either in power generation or in the demand sector falls between the IEA (International Energy Agency) WEO (World Energy Outlook) Current Policy Scenario (CPS) and the Sustainable Development Scenario (SDS) [88]. The increasing shares of renewables in gas through biomethane and hydrogen is essential: the CO₂ intensity per unit of energy of gas decreases considerably in 2040 compared to conventional natural gas moving from 0.8 to 0.1 and 0.13 kg CO₂/kWh in the DE and GA scenario respectively. The DE scenario generally shows a higher reliance on gas, due to a more relevant role of gas as a backup for distributed generation.

CCS will also be key to achieve the decarbonisation targets. ENTSOs’ assumptions on the need and application of CCS sees between 281 to 606

FIGURE 29
Combined demand for gas in 2045 in ENTSO-E scenarios in comparison to IEA scenarios
Source: Adapted from [100]
MtCO₂ capture, in line with European Commission’s Long-term Strategy [100].

Role of power to gas (P2G) in supporting renewable energy generation

Other studies demonstrated the feasibility of a close-to-100% renewable generation in Europe. Such configurations showed a high reliance on energy storage [99, 139]. In particular, Pleßmann and Blechinger (2017) found that pumped storage at current capacity levels would suffice to achieve large-scale fluctuating renewable energy generation integration up to 70% coverage of demand [139]. Power to gas (P2G) was a second-best option after pumped storage reached saturation. Even with higher storage costs, P2G capacities remained higher than batteries as they provide medium and long-term flexibility.

Gas in heating

Brown et al (2018) explored several cost-optimal solutions for the European grid through the integration of a set of flexibility options [98]. In evaluating the flexibility options, the authors highlighted the importance of seasonality in heat demand for buildings as well as the effect of population density. They presented a set of scenarios to study different combinations of the flexibility options for the use of gas. Each scenario was also evaluated for low-density (suffix L) and for high-density (suffix H) population areas.

The heating demand in Europe is more seasonally variable than the electricity demand; it is also positively correlated with wind in Europe and negatively correlated with solar energy. As shown in Figure 30, where the generation

Figure 30
Share of heating generation in buildings
Source: Adapted from [98]

¹As DSM options in transport: 50% of the EVs were allowed to shift their charging to the times when electricity was cheapest, minimising the charging costs; 50% of the EVs are allowed to not only shift their charging time, but also to discharge electricity back into the grid at times which are profitable (V2G) [98].
energy share for heating in buildings is presented, heating options would lead to diverse outcomes depending on the population density: district heating in high-density urban areas with long-term thermal energy storage and multiple technologies in rural areas. Heating generation differed from the capacity share quite remarkably: while the former was dominated by heat pumps, natural gas boilers represented most of the heating power capacity. This discrepancy between capacity and generation for heating depends on the asymmetry between cold peaks and heat pumps efficiencies. Hybrid heat pumps appeared to be more cost-competitive, functioning in combination with solar, than providing all heating demand using electricity. The latter option requires large overcapacities of gas power generation, making electric heating more expensive.

4.2.3. GLOBAL ENERGY SYSTEM MODELLING

Global studies of energy system transitions compatible with a 2 °C of temperature increase target provide useful insights in terms of energy systems integration as a flexibility option [140]. Here we draw conclusions from model comparison projects, where a set of models are questioned on scenarios under the same input assumptions. The Energy Modelling Forum (EMF) is one of the most authoritative examples of such initiatives. In this analysis part of the outcomes of EMF 27 are used [43-45]. 18 modelling groups performed scenarios with systematic variation of both policy and technology assumptions to explore the implications of technology availability on the feasibility and on costs of the energy systems transition. The EMF 27 approach aimed to quantify the relative role of specific technologies, such as carbon capture and storage (CCS), renewables, and biomass, at reaching the 2 °C target. The outputs from several models (AIM-Enduse 12.1, IMACLIM v1.1, IMAGE 2.4, MESSAGE V.4, POLES EMF27, and TIAM-WORLD 2012.2) were considered.

We examine two of the EMF 27 scenarios:

1. EMF27-450-FullTech (FullTech) which includes the full suite of technologies represented in the models; reference final energy intensity improvements per unit of gross domestic product mostly compatible with historical development since 1970 of about 1.2% per year; and

2. EMF27-450-LimSW (LimSW) which limits the share of electricity production from intermittent solar and wind technologies (wind and solar) to 20% of the total electricity generation.

Despite all model runs meeting the same decarbonisation target, model outputs vary in the emissions reductions between 20,000 and 28,000 Mt CO₂ emissions in 2050. In contrast to the European scenarios, the EMF 27 results put more emphasis on the role of CCS compared to intermittent renewables.

Figure 31 shows the cumulative primary energy supply and secondary energy in the power sector with a focus on the natural gas and the share of CCS. Values are presented as cumulative discounted values from 2020 through to 2050. The decarbonisation of the supply sector relies on fossil, mainly natural gas coupled with CCS; biomass with CCS dominates the primary energy share between 2050 and 2100.

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2 While current emissions targets require action to limit warming to 1.5 °C, the global modelling literature on meeting this target is not yet as comprehensive and amenable to synthesis as the literature addressing the previous 2 °C target.

3 Data downloaded from AR5 Scenario Database v 1.0.2 (May 2020) available at https://tntcat.iiasa.ac.at/AR5DB/dsd?Action=htmlpage&page=about#intro
In a context of limited non-biomass renewables (the LimSW scenario), on the supply side (Figure 31), low-carbon electricity generation tends to rely more on fossil fuels coupled with CCS and by 2050 the renewable share reaches a maximum of 13% (as opposed to 21% in the FullTech scenario). Natural gas with CCS represents about 48% of the total primary natural gas supply by 2050 and 45% in the FullTech scenario. This shows that, as renewables penetration increases, gas use decreases.

On the demand side, as low-carbon electricity is more expensive and a higher carbon price applies, sector coupling between gas and electricity becomes important for deep decarbonisation. Sector responses to electrification vary. A higher renewable share, in the Fulltech scenario, induces an increased electrification in most models, although at a small magnitude in industry, where generation would be slightly cheaper than the LimSW scenario. By contrast, the limited renewable energy scenario (LimSW) would induce a decarbonisation in the transport sector, the hardest sector to decarbonise, due to higher reliance on hydrogen consumption leading to about 30% of the transport final energy in most models (Figure 32). This result depends on the cost/availability assumptions proposed in each model and highlights a role for natural gas favouring energy systems integration. It should be noted, though that the temporal and geographical characterisation of global energy models generally overlooks supply-demand balancing at a time resolution as fine as the one adopted in power sector models, underestimating costs of sector coupling.
Energy systems costs were estimated as Policy Costs, reported in the variable “Additional Total Energy System Cost” from the selected model output of the EMF 27 study (Figure 33). The values are cumulative deviation costs of each scenario (FullTech or LimSW) from a baseline which has the same technology set but does not impose a 2 °C budget. Although absolute energy systems cost values would depend on the implicit assumptions on techno-economics of each model, being embedded in the baseline costs, the policy costs would represent exclusively the additional efforts required by meeting decarbonisation targets. Although only three models out of the six selected models (AIM-Enduse 12.1, IMACLIM 1.1, and TIAM) reported the policy costs, they align in showing a decrease in decarbonisation costs moving from a limited renewable scenario to one using the full set of decarbonisation technologies, including gas networks for flexibility support.

The main findings of this analysis are summarised below.

- If renewables deployment stalls then gas power generation with and without CCS can increase to meet a higher electricity demand, which supports energy systems integration for deeper decarbonisation.

- However, allowing significantly greater renewable penetration in models still retains a significant role for gas in power generation to provide final energy through natural gas or hydrogen in other end use sectors including heating and transport.

- There is an additional cost associated with increasing this share of natural gas in generation of between 6 and 15% as a higher adoption of CCS is required. In 2050, natural gas could represent up to 37% of the primary supply, 50% of which would rely on CCS technologies.

- The role of hydrogen in transport increases in response to lower renewable electricity penetration, with hydrogen, reaching about 30% of transport final energy. This shows the role of gas increasingly moving across multiple sectors in the future.
5. International experience: the case of gas in Brazil

5.1. The current energy system in Brazil

Brazil’s energy system has drawn increasing attention for its atypical dual role as a developing economy and global leader in low-carbon electricity generation due to the relatively high penetration of renewable hydroelectric power generation [142]. However, the Brazilian energy mix is still mostly non-renewable; 55% of primary energy comes from fossil fuels. Since the 1970s this ratio between renewable and non-renewable energy has remained. However, between 2000 and 2018 natural gas supply increased 3.5-fold. This demand in Brazil comes largely from power generation and industrial demand and does not follow the seasonal variability profile seen in Europe and the United States [143].

Energy supplies were considerably affected by the 2014 Brazilian economic crisis and have not yet recovered. Economic growth from the previous decade has been replaced by recession, with seven consecutive quarters of negative growth from 2014 to 2016. The 2016 gross domestic product (GDP) was smaller, in real terms, than the 2010 GDP, despite population increasing by 5.4% in the same period [144, 145]. Between 2014 to 2018, total energy demand fell 3% - with significant reductions from crude oil derivatives (12%) [146]. Brazil went from being a crude oil importer in 2014 (66,000 barrels net import) to a net exporter in 2018 (688,000 barrels net export). Natural gas imports also reduced considerably, falling 42% in the same period [146].

Another factor driving this transition is oil production, which has doubled between 2000 to 2018, while natural gas production has tripled. Electricity production, on the other hand, has gone from 20/80 fossil/renewable ratio in 1970 to 60/40 in 2018. The economic crisis of 2014/2015 has not caused the same pressure on production as it did in demand and internal supply, as can be seen in Figure 34.

5.1.1. Climate targets

Brazil’s Nationally Determined Contribution (NDC) is to reduce 43% of its emissions by 2030 compared to 2005 levels [147]. The country intends to reach this target by:

1. Increasing the share of sustainable biofuels in primary energy to approximately 18% by 2030;
2. Achieving 45% of renewables in the primary energy mix by 2030;
3. Expanding the use of renewable energy sources, other than hydropower, in the total energy mix to between 28% and 33% by 2030;
4. Increasing the share of renewables (other than hydropower) in the power supply to at least 23% by 2030;
5. Zero illegal deforestation by 2030 in the Brazilian Amazon; and
6. Restoring and reforesting 12 million hectares by 2030.

Although renewables already represent 45% of total energy supply [146], the power sector is still heavily dependent on hydropower and requires another 6% in other renewables by 2030 [148]. Biodiesel and ethanol represent 8% of primary energy, while diesel and gasoline represent 25%, leaving transport fuels some way short of the 18% biofuels 2030 target. In land use, deforestation continues, and reforestation and restoration...
programmes have not stopped that trend. The country has lost 17 million hectares of forest since 2005 [149].

A number of the studies regarding the future role of gas in Brazil do not adequately address impacts for climate change and the implications for NDCs. This is a fundamental challenge when assessing the potential for gas to provide flexibility in the future Brazilian energy system while limiting greenhouse gas emissions within Brazil’s current climate change commitments.

5.1.2. CURRENT AND PROJECTED SHARE OF GAS IN POWER GENERATION

Natural gas use in power generation has increased 12-fold from 2000 to 2018. This was largely due to the early-2000s drought related hydroelectricity crisis, which forced the government to create special policies for the development of natural gas power plants [150]. After the 2014 economic crisis, natural gas electricity generation fell 34%, to 9% of total generation, but was still the second highest source after hydropower (64%) [148].

The projected share of gas has changed in recent years. The Brazilian Energy Company (EPE) had projected the share of natural gas in electricity generation to be 7% (76 TWh) in 2030 for emissions to be in line with Brazilian NDC [151]. However, the 2019 Decennial Energy Expansion Plan by EPE indicates that by 2029 the share of natural gas in the power sector will be 4% (42 TWh) [152].
5.1.3. CURRENT GAS TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IN BRAZIL

Brazil has 9,500 km of transmission pipelines and 35,500 km of distribution pipelines. Figure 35 shows the majority of distribution pipelines are concentrated in the south/southeast regions, because of the large population and wealth in these regions. EPE also estimated another 2,000 km of new transmission pipelines [153], which also focus on the south and southeast regions. This is relatively undeveloped in comparison to other gas using regions such as the UK (>250,000 km of combined transmission and distribution pipelines) or the United States (>2,000,000 combined transmission and distribution pipelines), particularly given the size and population of Brazil [10].
5.2. POWER SECTOR: GAS AND FLEXIBILITY

As shown in Figure 36, Brazil’s power sector is mostly hydroelectric (73.5% of its total energy generation in 2018), followed by wind (8.2%) and natural gas (7.62%).

Although the high penetration of hydroelectricity brings several advantages, it also leaves the energy system vulnerable to weather and climate risks. Intense droughts can result in low reservoir levels, leading to electricity supply shortages, as happened in 2014. This has raised questions on how to:

- diversify the electricity generation mix;
- further expand hydropower capacity;
- incorporate other renewable sources that may include intermittency and further uncertainty; and
- establish the role of fossil fuels in the context of climate change mitigation and carbon abatement [156].

Thermal plants are thought to offer reliability and flexibility to the power system [157]. This section analyses the literature on gas and its potential for providing flexibility to Brazil’s power sector. It is divided into two areas: thermal power plants as backup and balance for renewable generation integration; and power-to-gas and gas storage as flexibility alternatives for the power sector. When possible, a value of flexibility is provided.

5.2.1. BALANCE AND BACKUP FOR RENEWABLE INTEGRATION SCENARIOS

Hydroelectricity will continue to play a dominant role in power generation over the next 10 years [156]. However, electricity demand is expected to continue increasing while hydropower capacity is now constrained by availability of suitable sites [158].

Wind power generation has seen an exponential growth [158]. The Ten Year Energy Plan aims for a 20 GW wind power capacity by 2027 [152]. Government policies, such as the Programme of...
Incentives for Alternative Electricity Source (PROINFA), which includes specific energy auctions for renewable technologies and distributed generation expansion policies, have paved the way for the growth of these technologies [158].

The diversification of the energy mix through renewables makes Brazil less vulnerable to climate change consequences such as droughts [158]. However, gas-fired thermal power plants may continue to be used to balance the electricity system and provide backup for renewables. Géremi Gilson and Ferreira [159] model the Brazilian energy system pathway to 2050, comparing a 100% renewable scenario with scenarios with a mix of renewable, nuclear and thermal power plants. They conclude that while the 100% renewable scenario is theoretically possible, the installed capacity required to support peak demand periods is substantially higher, and that higher reserve margins are required. Lucena et al. [160] compare a set of five climate policy scenarios for the Brazilian energy mix until 2050. While the observed penetrations of different technologies differ across models, all models see a relevant participation of natural gas regardless of climate policy. The following sections attempt to find flexibility values for gas as a balance for hydropower, and gas as a balance for wind power generation in Brazil.

Gas and balance for hydropower
Lap et al. [161] analysed a set of eight scenarios, using two soft-linked models. The TIMBRA least-cost optimisation model finds the lowest cost energy system, and the PowerPlan uses the installed capacity obtained to analyse supply and demand mismatches in 2050 and calculate the system’s reliability. The eight scenarios are designed to assess the Brazilian system’s reliability and additional costs in a low-carbon scenario in 2050. This work considers that the additional capacity needed to meet certain reliability targets given by international standards is fulfilled by flexible natural gas fired combined cycle (NGCC) power plants with CCS. The annual cost of this flexible capacity is calculated based on these assumptions and is called the “mismatch cost”. Table 3 presents their findings for three scenarios: a Base case with no resource constraint and no electric vehicle charging strategy, a Low case, with an electric vehicle smart charging strategy, and a High case, which uses an electric vehicle home charging strategy.

Marreco and Carpio [162] argue that thermal power plants can provide operational flexibility by being able to dispatch electricity in dry periods, thus avoiding mismatch costs. The authors propose a Real Options model, which they argue can aid in evaluating projects under uncertainty. While thermal power plants have fuel operating costs, hydroelectric operating costs are nearly zero, therefore preferred in dispatch models. However, sometimes thermal power plants are set to dispatch, in order to strategically save water in water reservoirs and avoid high mismatch costs in the future. They conclude that the value of flexible thermal power plants is 4.52 billion US$, representing 497 US$/MW/yr. This work does not consider climate/environmental metrics.

<table>
<thead>
<tr>
<th>Case</th>
<th>Capacity mismatch (GW)</th>
<th>Total mismatch cost (Billion US$/y)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>23</td>
<td>4</td>
</tr>
<tr>
<td>Low</td>
<td>10</td>
<td>2</td>
</tr>
<tr>
<td>High</td>
<td>42</td>
<td>7</td>
</tr>
</tbody>
</table>

Table 3 Flexible (mismatch) capacity covered by natural gas power generation with CCS and costs by 2050 for 3 scenarios. Source: [161]
Gas and balance for wind power generation

As discussed previously, higher penetration of wind and solar photovoltaic energy are being observed in Brazil’s power system. Larger shares of electricity supplied by these renewable sources pose challenges in the power sector, due to their intermittency. In order to accommodate large shares of wind power generation, the power system requires larger amounts of flexibility to guarantee stability and reliability [163, 164]. Brazil’s power system is composed of four interconnected subsystems: South, Southeast/Centre-West, Northeast, and North [165]. Hydropower represents the largest generation capacity and provides flexibility to the power system, with reservoirs providing large storage capacities (approximately 290 GW per month) [164]. Diuana et al [164] examine the impact of increasing wind power generation in southern Brazil. They compared:

- a high wind penetration system with secondary reserve supplied by hydropower; with,
- one with secondary reserve supplied by thermal power plants [164].

Results showed that balancing mechanisms could potentially be improved by setting thermal power plants as a secondary reserve. For the high wind penetration and hydropower secondary reserve scenario, a capacity factor of 55% for gas power plants was obtained for 2030. For the high wind penetration and thermal secondary reserve scenario, the capacity factor of gas power plants by 2030 was found to be 69%. For both scenarios, however, there was no participation of gas power plants observed by 2050, even when imposing thermal plants as secondary reserve. What was observed was a combination of thermal power plants supplied by coal and biomass for the study’s techno-economic assumptions.

In the context of the government’s plans to build 26 large hydropower plants in the Amazon basin, de Faria and Jaramillo [166] simulate five alternative capacity expansion scenarios for meeting the country’s electricity demands:

- The Baseline Scenario considers the planned large hydroelectric power expansions;
- Scenario 1 replaces scheduled hydroelectric power plants with wind farms, reaching a total of 27% of total installed capacity by 2028;
- Scenario 2 simulates a wind total installed capacity of 39% by 2028;
- Scenario 3 assumes hydroelectric power plants are replaced by natural gas combined cycle power plants;
- Scenario 4 assumes the same wind capacity as for Scenario 2 while additionally replacing all current coal, oil, and diesel power plants with natural gas power plants.

A comparison between Scenarios 2 and 4 gives insights into the cost of flexibility provided by natural gas in high renewable penetration scenarios. Both scenarios present a share of renewables of 82% by 2028, with 40% of the system’s capacity met by non-large hydro renewables. By 2028, the average marginal costs of Scenarios 2 and 4 are 101 US$/MWh and 90 US$/MWh respectively, representing what could be a value of gas for flexibility of 11 US$/MWh marginal costs, when compared to other thermal plant alternatives. Additionally, the difference in direct GHG for both scenarios is 860 vs. 710 MtCO$_{2}$-eq for the period between 2013 and 2028. It is also worth noticing that when considering direct thermal GHG emissions plus hydropower GHG emissions between the whole period, both high wind scenarios (Scenarios 2 and 4) outperform the Baseline Scenario. Considering the whole period, the total GHG emissions of the Baseline Scenario, Scenario 2, and Scenario 4, are 920, 860, and 710 MtCO$_{2}$-eq respectively. However,
the annual direct emissions continue to be higher in all scenarios compared to the baseline.

### 5.2.2. POWER-TO-GAS AND STORAGE

Another two possibilities for gas to provide flexibility to the power sector is through power-to-gas technologies and via gas storage. The State of Ceará in the Northeast Region has one of the highest wind potentials in the country, estimated at 14% of the state’s installed power capacity [167], along with a natural gas grid. Patrício et al. [168] argue that as the State has a high penetration of intermittent wind and solar energy together with an extended natural gas pipeline, these conditions are favourable for the storage of energy as hydrogen, and its partial injection into the natural gas grid. They model the production of hydrogen through water electrolysis sourced from surplus wind energy, taking into account techno-economic parameters for energy demand and supply, macroeconomic and social aspects, and environmental impacts. For two scenarios that assume a fast and a slow hydrogen adoption, the profit per unit of energy demand for the State evolved over time. The fast hydrogen adoption scenario sees a profit of 0.04 US$/mWh, 0.56 US$/MWh, and 1.56 US$/MWh by 2030, 2050, and 2070, respectively, while the slow hydrogen adoption scenario sees a profit of 0.04 US$/MWh, 0.38 US$/MWh, and 1.12 US$/MWh for the same series of years.

Almeida et al. [143] calculate the economic value of underground gas storage (UGS) for natural gas to provide flexibility for the Brazilian power sector. They analyse the Brazilian gas and power markets and conclude that, as opposed to other countries, natural gas demand in Brazil is not seasonal. Conversely, it has a random profile, associated to providing balance through thermal power plants to complement hydroelectric power generation. Simulating a UGS facility for the period of 2006-2015, they estimate the internal rate of return (IRR) of such a project as 18%, with a net present value (NPV) of 263.73 million US$. The authors also performed an uncertainty analysis varying the UGS facility’s both capital and operating cost by 50% in both directions. The UGS facility valued here assumes a volume of Working Gas of 1.5 billion m³, equivalent to 15.7 TWh. The authors conclude that UGS facilities have a positive economic value in the Brazilian power sector, but they did not consider any environmental or climate issues.

Another study conducted by de Souza Noel Simas Barbosa et al. [169], compared two renewable energy scenarios in Brazil through an optimisation model, to analyse the role of storage technologies for renewable integration. The modelling approach divides Brazil into 5 regions, and considers hourly demand profiles across sectors, including possible synergies between different system components when relevant. They considered two scenarios: a national open trade scenario accounting for renewable energy generation and storage technologies to meet electricity demands; and a scenario that integrates water desalination and national natural gas industrial demands into the energy system. In both scenarios renewable sources can be coupled with power-to-gas technologies for electricity generation and storage. The integrated scenario implements them as bridging technologies between electricity, desalination and industrial demand sectors. The country-wide levelised cost of electricity is 61.1 €/MWh and 53.4 €/MWh for the open trade and integrated scenarios respectively, indicating that the integration of sectors through power-to-gas technologies reduces the cost of electricity by 7.7 €/MWh.
5.2.3. POWER SECTOR SUMMARY FINDINGS

The examined literature provides a range of various metrics and assumptions that can be understood as different values for flexibility of gas in the power sector. These vary across different scenarios for system integration, climate metrics, and adoption of different technologies. Because of the wide range of metrics and assumptions, the values are difficult to compare directly. The findings for the different metrics, their values, and ranges (when available), are summarised in Table 4.

5.3. RESIDENTIAL AND COMMERCIAL ENERGY CONSUMPTION

Brazil’s residential, public, and commercial sectors are largely supplied by electricity. Figure 37 shows the evolution of total energy consumption for these sectors countrywide. The residential sector accounted for 67% of total consumption in 2018. Of total residential consumption, around 46% was electricity, followed by LPG and firewood with 26% and 25% of the total consumption respectively.

According to ProCel [171], the Brazilian Centre for Information in Energy Efficiency, energy services of space and water heating are mostly supplied by electricity in the residential sector. The use of firewood and LPG are mostly for cooking, although cooking can also be electric [172]. There is a low penetration of natural gas in urban environments and a low penetration of distribution pipelines observed in Figure 35. Therefore, the value of gas for flexibility in urban environments is upstream in the power sector, as discussed above [157].

Space heating demand in Brazil does not represent a significant consumption across sectors [171, 172], as it does in other countries in the Northern Hemisphere. However, Wahl and Filho [173] argue that there are increasing concerns on space-heating in the South of Brazil, due to changes in the climate that have generated particularly cold winters over the past few years. This could lead to some penetration of natural gas at urban levels.

Jalil-Vega et al. [174] built the COMET model, a spatially resolved energy systems model that trades-off energy supply, infrastructure, and end-use technologies to provide energy service demands for heating, space-cooling, transport, and appliances. Demands for energy services for the city of São Paulo were estimated, and the model was applied to study energy transitions to meet Brazil’s NDCs. No significant

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value (range)</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flexible (mismatch) capacity natural gas + CCS by 2050</td>
<td>173,900 (166,700-200,000)</td>
<td>US$/MW yr</td>
</tr>
<tr>
<td>Flexible capacity of natural gas without carbon metrics</td>
<td>497 (51,814)</td>
<td></td>
</tr>
<tr>
<td>Marginal cost of gas generation flexibility</td>
<td>11</td>
<td></td>
</tr>
<tr>
<td>NPV UGS</td>
<td>16.8</td>
<td>US$/MWh</td>
</tr>
<tr>
<td>Levelised cost PtG + Storage + Industrial generation integration</td>
<td>8.6</td>
<td></td>
</tr>
<tr>
<td>Profit by 2050 PtG + Storage (slow-fast hydrogen adoption scenarios)</td>
<td>0.38-0.56</td>
<td></td>
</tr>
</tbody>
</table>
contribution of natural gas or hydrogen technologies was observed as a cost-effective way to supply commercial and domestic demands through 2050 nor provide flexibility to the urban system under climate target scenarios. Some participation of compressed natural gas and hydrogen technologies was observed in the heavy-duty transport sector, discussed below.

5.4. FLEXIBILITY IN INDUSTRY: A STUDY OF THE ETHANOL INDUSTRY AND BIOGAS POTENTIAL

Within the ethanol industry in Brazil, there is the potential to improve efficiency and contribute to flexible energy supply. A number of studies examine the potential to harness this opportunity. The next section will deal with the case study of ethanol mills and the on-site production of biogas as a flexible energy source.

5.4.1. GAS USE IN BRAZILIAN INDUSTRY

Since 2010, the use of natural gas in Brazilian industry has remained steady at around 10% of the sector’s energy consumption, varying from 9.5% in 2009 to 11.4% in 2018 [146], though use as a feedstock declined 60% from 2010 to 2018 [146]. The sector was responsible for 28% of Brazilian natural gas consumption in 2018.

The natural gas price for industry in Brazil has traditionally been relatively high, which has limited its use in industry. Figure 38 shows the comparison of Brazilian natural gas for the industry in 2018 with other countries [175]. The price formation in Brazilian industry is based on a regulated concession [176], and the spot price typically paid on the wholesale market is more closely aligned with European markets [177].

The relative lack of existing gas infrastructure and the high costs of new infrastructure is also a barrier, hindering new entrants to the Brazilian natural gas market. The higher price of energy also affects industries international market competitiveness, impacting on important industrial sectors such as steel, iron, aluminium, fertilisers, ceramics, glass and pulp and paper [175].
5.4.2. BIOGAS AND BIOMETHANE PRODUCTION FOR VEHICLE FUEL OR ELECTRICITY GENERATION

Vinasse, a by-product from the Brazilian ethanol industry, can be used as a feedstock to produce biogas, which is mainly methane (CH\textsubscript{4}) and carbon dioxide (CO\textsubscript{2}), as well as moisture, H\textsubscript{2}S and other impurities. Biogas is transformed into biomethane by undergoing cleaning and upgrading [10, 178].

Biogas can be used in electricity generation to supply necessary plant energy or as a fuel to substitute for diesel in transportation and agricultural equipment [178, 179]. If biogas is upgraded to biomethane, a third potential use is as a substitute for natural gas, in the case of producers having access to gas pipelines network or liquefaction plant. The detail of biogas use in electricity generation as well as in heavy-duty machinery and the implicating costs of such deployment, however, is lacking in the literature. In the case of electricity generation, the adaptation of the existing equipment to burn biogas (as humidity control, biogas flow, flame stability, boiler flame, etc) must still be fully evaluated to produce comprehensive cost comparisons. In the case of heavy machinery, on the other hand, the compatibility of gas engines with the required capacity necessary within mill activities must be evaluated and properly assessed to, again, guarantee comprehensive comparisons.

In the 1970s ethanol mills produced some energy using waste residue bagasse [179] and used supplementary wood fuel [180] and electricity purchased from the grid to satisfy the remaining energy needs. With the subsequent expansion of the industry, mills started to improve efficiency and decrease steam consumption, reducing supplemental energy purchase and resulting in surplus bagasse in of the order of 5 to 10%. There was no incentive to generate surplus electricity for sale or to improve plant efficiency due to the low price offered for electricity during the 1980s and 1990s [179].

By the mid 1990s, regulatory changes, and increases in electricity price led to surplus electricity traded as a third product (after sugar and ethanol). Mills installed more efficient units, and since 2007, the use of high-pressure boilers became the standard in new installations, helped by development incentives [179].

Electricity generation from bagasse is seasonal, since it is produced during the harvest period. With increasing interest by mill operators to increase revenue, and with compelling electricity
prices, there is an interest for generating electricity in the off-season [179, 181]. Wood residues, straw and biogas are the most probable options [179, 180, 182].

Generation in the off-season is usually studied for the most efficient plants that have the sale of surplus energy as one of their products. Whatever the new fuel, the boilers must undergo some modifications when switching fuel [179, 180, 182-185].

Comparing the technical-economic viability of biogas end uses

In recent literature, comparing electricity generation and diesel use within mill activities, authors show that biogas generation from vinasse is a promising opportunity, mainly for the substitution of diesel, as it was the only economic application [186]. For most of the price scenarios performed, electricity generation from biogas was not economically feasible. Despite this, the application may not be completely rejected as an alternative, especially when diesel prices are low.

This highlights the value of having adapted infrastructure to be able to take advantage of biogas when diesel prices are low and electricity prices are high, and vice-versa.

In another study, the energy potential from vinasse from a single sugarcane biorefinery is compatible with the energy demand of a city of 130,000 inhabitants [185]. Furthermore, biogas could replace up to 40% of the annual diesel supply in agricultural operations and still provide approximately 14 MWh annually from cogeneration. This study also confirms that investment in a biorefinery with an anaerobic digestion plant is economically more attractive for biogas as a diesel replacement in agricultural and transport operations [185]. Sugar and anhydrous ethanol production costs were consistently lower for a similar biorefinery, even though a higher investment was required for a sugarcane mill with vinasse anaerobic digestion. Overall, the use of biogas for diesel replacement allowed for a decrease in production costs, either for annex plants (those that produce sugar and ethanol) or for autonomous plants.

From the costs perspective, Leme et al (2017) [187] presented a technical-economic assessment of biomethane production from vinasse in the Brazilian bioethanol industry, considering five technological routes of biogas upgrading. The biomethane costs of the five technological routes overlapped in the range between 13 US$/GJ and 14 US$/GJ (47 US$/mWh and 50 US$/mWh), which indicates a certain equivalence of the options. These costs are comparable to the prices of alternative fuels, such as Bolivian natural gas (8 US$/GJ) or

<table>
<thead>
<tr>
<th>Source</th>
<th>Substrate</th>
<th>Evaluated</th>
<th>Viability</th>
<th>Indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>[186]</td>
<td>Vinasse</td>
<td>Diesel and electricity</td>
<td>Diesel most viable</td>
<td>Profit (Brazilian reais)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>IRR electricity: 12.1-13%</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>IRR diesel: 12.3-14%</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>NPV (million US$) electricity: 4-15</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>NPV diesel: 5.1-31</td>
</tr>
<tr>
<td>[185]</td>
<td>Vinasse</td>
<td>Diesel and electricity</td>
<td>Diesel most viable</td>
<td>Cost of biomethane production: 29-34 R$/GJ</td>
</tr>
<tr>
<td>[187]</td>
<td>Vinasse</td>
<td>Diesel and natural gas network</td>
<td>Diesel most viable</td>
<td></td>
</tr>
<tr>
<td>[188]</td>
<td>Vinasse</td>
<td>Electricity generation</td>
<td>Viability depends on scale</td>
<td>Minimum scale for viability: 6,000-14,580 hectares</td>
</tr>
<tr>
<td>[189]</td>
<td>Pentose sugars</td>
<td>Biogas and n-butanol</td>
<td>n-butanol most viable</td>
<td>IRR biogas: 11.3%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>IRR n-butanol: 13.1-15.2%</td>
</tr>
</tbody>
</table>
The environmental impacts of biogas in its different end uses

Moraes et al [185] also evaluated the environmental impacts in terms of GHG emissions. In their study, the emissions avoided from diesel replacement were almost twice as high as those from electricity displacement. The authors estimated that the GHG emissions avoided corresponded to transportation emissions from cities with populations of 31,000–42,000 people. Furthermore, the yearly emissions reductions from biogas in Brazil would be equivalent to the transportation emissions from cities with populations of 6.5 million to 8.5 million people if biogas was used in electricity generation or diesel, respectively [185].

Ferreira et al [190] studied biomethane use in domestic cooking, light-duty and heavy-duty vehicles. Although the study analyses uses outside the industry, the environmental benefits of using biogas in heavy-duty vehicles could also be applied to the mill’s internal heavy-duty needs. Interestingly, the authors performed a life cycle analysis in four impact categories: acidification, climate change, eutrophication and photochemical oxidation. The results showed that the replacement of diesel in heavy-duty vehicles was beneficial in all impact categories.

In [183], three distinct biogas uses were analysed in terms of GHG emissions and energy balance (fossil/renewables): injection in the natural gas grid, electricity generation and diesel replacement within sugarcane mills. Their results show that GHG emissions in a typical Brazilian distillery can be improved by up to 12.1% using vinasse biogas for electricity, compared with a distillery that does not adopt this.
practice. In terms of energy balance, the production of electricity with biogas from vinasse can improve the ethanol performance by up to 4.7% compared to the mills with current production practices (no biogas). The projected result for a mill injecting biomethane into the grid is an improvement of up to 10.7% in its energy balance, based on current production practices. Concerning GHG, the biomethane injected into the grid can represent up to 11.1% reduction with current practices.

The GHG emissions from distilleries with dual-fuel diesel-gas trucks and harvesters will be affected by a larger emission factor from diesel than natural gas, compared to just injecting gas into the gas grid. However, the authors stress that this effect is limited by the number of consumers that can use such technology and by the higher energy use resulting from the biomethane compression dual-fuel use. The use of biomethane from vinasse represents commercial and logistics advantages for diesel replacement as diesel use within mills coincides with the biogas production.

### TABLE 6
Summary of finding from reviewed papers on environmental performance

<table>
<thead>
<tr>
<th>Source</th>
<th>Substrate</th>
<th>Evaluated</th>
<th>Impact category</th>
<th>Indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>[185]</td>
<td>Vinasse</td>
<td>Electricity in cogeneration</td>
<td>Climate change</td>
<td>Electricity in cogeneration: -20-28 ktCO2e/year</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Electricity in stationery engines</td>
<td></td>
<td>Electricity in stationery engines: -19-27 ktCO2e/year</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Diesel replacement</td>
<td></td>
<td>Diesel replacement: -25-34 ktCO2e/year</td>
</tr>
<tr>
<td>[190]</td>
<td>Vinasse</td>
<td>Biogas substituting: LPG in ovens, gasoline in light-duty and diesel in heavy-duty vehicles</td>
<td>Acidification potential</td>
<td>Ovens: 0,0% change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Climate change</td>
<td>Light-duty: 745,9% change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Heavy-duty: -79,9% change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Eutrophication</td>
<td>Ovens: -99,7% change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Photochemical oxidation</td>
<td>Light-duty: -90,8% change</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Heavy-duty: -90,3% change</td>
</tr>
<tr>
<td>[183]</td>
<td>Vinasse</td>
<td>Biogas injected into natural gas grid</td>
<td>Climate change</td>
<td>Natural gas grid: -7.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Electricity generation</td>
<td>Energy balance (fossil/renewable ratio)</td>
<td>Electricity generation: -6.9%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Diesel replacement</td>
<td>Energy balance</td>
<td>Diesel replacement: -7.2%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Natural gas grid: 7.9%</td>
<td>Energy balance</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Electricity generation: 3.5%</td>
<td>Natural gas grid: 7.9%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Diesel replacement: 27.0%</td>
<td>Electricity generation: 3.5%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Diesel replacement: 27.0%</td>
</tr>
<tr>
<td>[188]</td>
<td>Vinasse</td>
<td>Electricity generation</td>
<td>Climate change</td>
<td>Climate change: -1.9 Mt CO2/year</td>
</tr>
</tbody>
</table>
geographically and seasonally. The authors also corroborate the idea that dual-fuel machinery increases flexibility of the mill to operate only with diesel in the off-season period, when no gas is available for most mills, or when prices are not attractive.

Finally, [188] evaluated the total energy potential of biogas for electricity generation and estimate that this use may reach 3.26 TWh/year, which represents 0.52% of all Brazilian energy consumption (in 2014). The potential to avoid emissions reaches 1.9 Mt CO2/y, which is approximately 2.1% of the emissions for the whole industry in Brazil in 2014.

Summarising, the substitution of diesel is the most environmentally beneficial use of biogas in sugarcane mills in terms of climate change, even though electricity generation and injection in the natural gas grid also bring emissions reductions (Table 6) [183, 185, 188]. Furthermore, using biogas in heavy-duty vehicles is also helpful to avoid eutrophication, acidification, photochemical oxidation impacts and to improve the energy balance of sugarcane mills towards more renewable energy inputs [183, 190].

5.4.3. FLEXIBILITY OF SUPPLY: BIOGAS POTENTIAL TO SUBSTITUTE NATURAL GAS

The use of biogas and biomethane as an energy source can contribute to achieving the goals of existing climate policies in São Paulo State and Brazil. Emissions from the Brazilian energy sector have increased 15% since 2010 (even with an economic crisis in 2011-2015). This is due to the increased use in fossil fuel for electricity and the increase in gasoline consumption due to the lack of ethanol’s economic competitiveness. Since in 2014 the Brazilian Federal Government decided to control gasoline prices, hence, biogas and biomethane may have a crucial role in achieving climate goals first by substituting natural gas in the gas grid and secondly by substituting lignocellulosic material in sugarcane mills in electricity generation, freeing this feedstock for second-generation ethanol production [191].

Brazil has standardized biomethane derived from biogas produced from agro-industrial and forestry residues through the National Agency of Petroleum, Natural Gas and Biofuels (ANP) in 2015. Following the national regulation, several states have created legislation to incentivize biomethane injection into the gas grid, e.g. São Paulo State with the “Paulista Biogas Program”; Rio de Janeiro State created the “State Renewable Gas Program”; Espirito Santo State created the “State Policy for the Incentive of Renewable Energies” and Rio Grande do Sul State created the “Program of Incentive to the Generation and Use of Biogas” [178].

Although legislation exists, the incentives for biogas and biomethane in Brazil are still marginal compared to other countries such as Germany, Switzerland or the UK [178]. Brazil has a few biogas plants, as shown in Figure 39. According to CIBIOGAS there are currently 155 biogas plants in Brazil, 43.8% using biogas from animal residues and 28.4% from industrial (food, beverage and dairy) and agro-industrial waste [192]. The biogas plants are mostly concentrated in the Southeast and South regions of the country and use biogas mainly for power generation.

When it comes to the injection of biomethane into the existing NG pipelines, only 13 biogas plants currently produce biomethane and would be able to supply to the grid. [192]. However, this number could be much larger since many ethanol plants are not located near the existing NG infrastructure.
São Paulo state is especially important in the use of biomethane, first for ethanol production, and second for the extension of the natural gas grid in the state. Figure 40 shows the municipalities with the highest biogas potential from ethanol vinasse and their proximity to the natural gas grid.

The EPE states that there are 66 mills located up to 20 km from the existing NG pipelines, with a potential production of 3.0 million Nm³ of biomethane per day, corresponding to 20% of São Paulo State NG consumption [194].

Considering the huge potential of biogas and biomethane in São Paulo, the state government has been improving the state legislation related to biogas policy since the creation of the “Paulista Biogas Program” in 2012 and in 2017 the Energy Regulation agency of the State São Paulo (ARSESP) started developing the regulation for biomethane injection in the state of São Paulo, which was approved by the State Energy Council in the same year [178].
5.5. BRAZIL CASE STUDY
SUMMARY FINDINGS

Gas has a limited role in markets such as Brazil due to the relative lack of existing pipeline infrastructure. However, in Brazil there is a role for flexible thermal plants to support hydroelectric stations and the increasing penetration of intermittent renewable electricity generation. Climate commitments make the role of unabated gas challenging closer to 2050 unless gas networks are decarbonised through biogas/biomethane and hydrogen. There is a significant potential for biogas and biomethane to play a role in that decarbonisation given the opportunities in the sugarcane industry, though increased infrastructure will be necessary to connect these plants to the existing gas network. The most valuable use for the sugarcane industry’s waste biomass, from both an economic and environmental perspective, may be in substituting diesel as a vehicle fuel, though in cases of certain plant size or underlying diesel price, electricity generation or biomethane injection to the grid may be optimal.

As in other regions, the use of power to gas as a way to manage intermittency and curtailment in renewable electricity generation has been examined in Brazil, and the maintenance or extension of gas infrastructure will help the maximise the value of power to gas in the future.

The significant challenge for countries like Brazil with low-carbon electricity already prevalent in the electricity system is how to utilise the flexibility value of gas without significantly increasing emissions and endangering climate commitments.

FIGURE 40
Biogas plants, existing gas grid and grid under evaluation (2020)
Source: [193]
6. Discussion - Conclusion

6.1. SUMMARY OF MAIN FINDINGS

6.1.1. CURRENT GAS NETWORK FLEXIBILITY AND VALUE
The existing natural gas network provides a significant role to the energy system through its inherent flexibility. That flexibility is provided through several mechanisms including:

- backup gas electricity generation;
- gas network linepack, or the gas stored as pressurised gas in gas pipes;
- natural gas storage, such as underground geological gas stores; and
- gas imports through pipeline and LNG terminals.

Daily demand variation can be met by changing the pressure of linepack within higher pressure tiers of the transmission and distribution gas networks, and through the variation in supply onto and off the system including from gas storage. Seasonal demand variability is more challenging, and is met through varying supply from interconnection, LNG and in many countries by seasonal storage.

The trend in flexibility provision is similar across the regions examined. The UK, Europe and the United States have all experienced a reduction of natural gas storage capacity. In the UK and Europe this has been attributed to the increasing capacity for imports through interconnection pipelines and LNG markets. In the United States the role of increasing domestic production is thought to have played a significant part in reducing storage capacity.

Indicators of flexibility value such as summer-winter spreads and the trend in gas storage capacity reduction suggest that the provision of interseasonal flexibility has become increasingly competitive to provide to the gas network.

In the UK, summer-winter spreads ranged from a peak in 2005 of 1.5 p/kWh to around 0.4 p/kWh in 2020 and a low of 0.2 p/kWh in 2017. Europe follows a similar trend, with a high of 5.3 EUR/MWh in 2008 to 0.6 EUR/MWh in 2018. In the United States the 2018 difference between spot price and January delivery future price was relatively low, at 20 cents per million BTU, compared to a relative high of 69c per million BTU in 2016.

6.1.2. FUTURE GAS NETWORK FLEXIBILITY
The literature on the future role of the gas networks and flexibility focuses on the role of gas in supporting the electrification of the energy system in the pursuit of decarbonisation. Several studies that examine the use of gas networks into the future commonly estimate a positive value for the role that they play in providing flexible energy across daily and seasonal energy demand variation.

However, a transition to low carbon gas networks is likely to require hydrogen, biomethane and fragmentation of gas networks as neighbouring infrastructures begin to choose different vectors or potentially remove networked gas entirely. These factors are all likely to impact the cost of flexibility provision with the potential to increase the cost of flexibility in the gas network. For example, a future hydrogen gas network is likely to be isolated, without imports through interconnected pipelines or other international markets, which are key measures that have reduced flexibility costs. Under these conditions,
hydrogen storage will be needed to carry the burden of seasonal flexibility. This limits the usefulness of examining existing gas networks as an indicator of future gas network flexibility; much of the cost reduction in current natural gas networks has been attributed to gas production, interconnection and LNG markets. For daily flexibility needs, the future gas network will likely be more fragmented and may carry hydrogen, which is less energy dense than natural gas. These factors will likely impact the availability of linepack to meet daily demand variation, again requiring short term storage or flexible production to help supply match variable demand.

Hybridisation of gas and electricity networks has the potential to provide energy at times of peak demand while minimising total use of gas, contributing to energy system flexibility. Where this has been studied, there are potential, though small, cost savings against more electricity centric scenarios, in the order of 5%. However, there are questions over the maintenance of gas networks to transport relatively small volumes of gas.

Whole system modelling of future gas networks provides some insight into the potential economic value of maintaining gas networks for flexibility value. A comparison of modelling at the global level indicates a system cost reduction in the order of 6% and 15% moving natural gas into a flexibility-oriented role as compared to a scenario where gas and CCS displace a larger proportion of renewables in the energy mix.

In Europe a similar story exists, with studies showing gas playing an important role in providing flexibility to support the increased penetration of renewables and providing peaking energy to heat in the domestic sector to support electricity and heat pumps. At the same time, the introduction of hydrogen and biomethane reduces the emissions associated with gas, with some estimates suggesting gas reducing from 800 g CO₂-eq/kWh to the order of 100 g CO₂-eq/kWh by 2040.

Studies of the UK energy system indicate that decarbonised gas networks and hybridisation opportunities can play a role in meeting even net zero emissions targets. System costs across electricity biased, hydrogen-biased and hybrid scenarios are similar, with a small economic benefit to hybrid scenarios and a significant additional cost in a hydrogen biased net zero scenario.

6.1.3. GHG IMPACTS OF GAS NETWORK FLEXIBILITY

The gas network provides flexibility at a relatively small energy and therefore GHG cost. This is across all timescales. The grid energy use difference between winter and summer leads to GHG emission in the order of 1-2 g CO₂-eq/kWh, though this is declining over time due to reduced usage and increased volumes of LNG in the gas market. LNG and gas storage use in the order of 0.5 g CO₂-eq/kWh, though this does not include transport emissions of LNG amongst other issues. This can be compared to the combustion emission of natural gas of 184 g CO₂-eq/kWh.

6.1.4. GAS NETWORK FLEXIBILITY IN BRAZIL

Opportunities in developing gas markets such as Brazil exist but are limited by the relative lack of existing gas infrastructure, particularly the pipeline network to domestic and commercial consumers. However, in Brazil there is a role for flexible thermal plants to support hydroelectric stations and the increasing penetration of intermittent renewable electricity generation. There is a significant potential for biogas and biomethane to play a role in that flexible backup role given the opportunities in the sugarcane industry to produce these low carbon gases for sale or use them to
generate power in high efficiency thermal plant. Increased infrastructure will be necessary to connect these plants to existing networks.

As in other regions, the use of power to gas as a way to manage curtailment in renewable electricity generation may also be relevant in the Brazilian context, and the maintenance or extension of gas infrastructure will help the maximise the value of power to gas in the future.

The significant challenge for countries like Brazil with low-carbon electricity already prevalent in the electricity system is how to utilise the flexibility value of gas without significantly increasing emissions and endangering climate commitments.

6.2. IMPLICATIONS FOR POLICY

The emerging demonstration of various aspects of future gas networks provides significant opportunities for research into the flexibility provision and costs resulting from these fundamentally different gas systems. Research to examine these issues alongside the development of demonstration projects should be pursued to keep abreast of emerging data and keep policy informed of those developments and their implications for decision-making.

Natural gas has traditionally been able to provide flexibility, particularly seasonal, at relatively low cost, and this has become cheaper in recent years as import markets have increased. However, maintaining gas networks whilst also reducing GHG emissions will require changes to the gas network that will fundamentally influence their flexibility. Until a significant international market in biomethane or hydrogen trade exists, the burden of flexibility provision within these low carbon networks will lie with linepack and storage. Policymakers should be aware that the flexibility provision, and the cost of providing it will not follow the analogy of the current natural gas network in the short term. In the longer term, policy levers to support the development of hydrogen or biomethane trade routes could be pursued. This could include:

- Establishing targets and/or long-term policy signals;
- Supporting demand creation;
- Mitigating investment risks;
- Promoting R&D, strategic demonstration projects and knowledge sharing; and
- Harmonising standards, removing barriers.

In hybrid scenarios, where gas may play a small but important role in meeting peak energy demand, climate targets can still be met. However, maintaining gas networks with relatively limited volumes of gas will be challenging and require changes to pricing and business models, likely to require some level of support if they are to be successful. However, research suggests that the costs of operating and maintaining the gas network under low gas volumes is economical when compared to hydrogen-focused or electricity-focussed scenarios that meet the same emissions reduction. The consumer acceptance of such hybrid models may also be challenging and may require careful planning and communication if they are to reach any significant scale.

6.3. FUTURE RESEARCH

Scenario modelling in the UK suggests that total system costs are relatively even across different scenarios that include gas networks, including natural gas, hydrogen and hybrid solutions. Work to understand the spatial and consumer aspects of those solutions in more detail would be valuable in understanding what role and where can gas networks make the most useful contribution in a future energy system that requires a range of...
solutions to flexibility challenges.

The ability of the gas network to accommodate greater levels of renewable generation is an area of continued research interest, particularly from a multi-vector and circular economy perspective that includes green gas from anaerobic digestion, hydrogen electrolysis and BioSNG.

The impact of changing linepack and storage energy density on costs of delivering flexibility is another area that warrants further study.

Better understanding of the costs of operating gas networks with relatively low gas flows is an emerging research priority, particularly given the positive performance hybrid scenarios have seen in modelling studies. This should include examination of the business models and pricing structures that will be necessary to fund gas networks despite decreasing gas flows and increasingly variable demand flows.

The GHG implications of flexibility provision, particularly for future gas grids that carry biomethane and hydrogen, have not been examined in the literature, and this is an area that could receive further attention. Application of lifecycle assessment models to examine the consequential emissions associated with choices surrounding flexibility options could improve understanding of these issues and allow for more meaningful comparison.

Finally, an examination of what is lost in the value of gas network flexibility by moving to smaller, fragmented networks is an area for future research. A key aspect of fragmented networks is the lack of imports through pipelines and liquified gas routes. This research should also include projections of timescales for development of international trade of hydrogen and other low carbon gases, and the economic impacts on these networks of improving international markets for low carbon gas.

6.4. CONCLUSIONS

The evidence examined in this report clearly highlights the value that natural gas networks have traditionally provided to the energy systems in a number of regions with challenges of daily and seasonal demand variation. However, gas use and gas networks are likely to undergo significant changes in the near future in response to climate targets. Maintaining gas networks in a form that is consistent with climate goals may allow those types of flexibility to operate in future energy systems around the world, supporting not just traditional demand variation but also the emerging challenges of increasing electrification and intermittent electricity generation. Any emerging low carbon gas network will involve significant changes to existing infrastructure that will fundamentally change their flexibility characteristics. Research is ongoing on the potential paths for low carbon gas network development and the challenges of providing the necessary flexibility to support the future energy system. It is important for that research to continue, and to inform emerging policy decisions that define the development of energy system infrastructure in the future.
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