RIIO GD2 Business Plan Appendix

Future of Energy: Whole Systems & Scenarios

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1. Whole System Background

1.1 Summary

There has been a paradigm shift in sources of energy, how and where they connect to our networks and the way they operate. Historically discrete gas, power and transport systems are seeing ever increasing integration and changes in operation.

In the previous Energy Systems Transition chapter, we have set out how we will play a leading role in evidencing the pathway to decarbonisation, supporting green gas and establishing Hydrogen as a critical energy vector. Coupled with this, there are alternative trajectories for decarbonisation, many at different stages of development and technology readiness. There is uncertainty as to which solution will deliver the decarbonisation that the world rightfully seeks and how this will be co-ordinated on a global scale. We therefore need to tread carefully with assumptions and scenarios, rather than real indications, from markets and customer choices for example, when determining asset investment plans.

Aside from all the legislation and regulatory mechanisms in place to govern our operations, our primary role as an energy network operator is to facilitate and connect sources of energy to customers that want and need it through our extensive energy network. It is not our role to choose the means of decarbonisation, rather to provide options, deliver energy responsibly, safely and reliably to all our customers and be responsive and flexible to their emerging needs.

For decades, the UK's gas and electricity networks have operated largely as discrete systems. Those touch points that did exist were gas-fired generation plants operating primarily at transmission level. Similarly, within the gas and electricity sectors, interfaces between transmission and distribution were relatively simple, with both sectors designed to operate in a 'top down' configuration with energy flows from high to low voltage and pressure respectively.

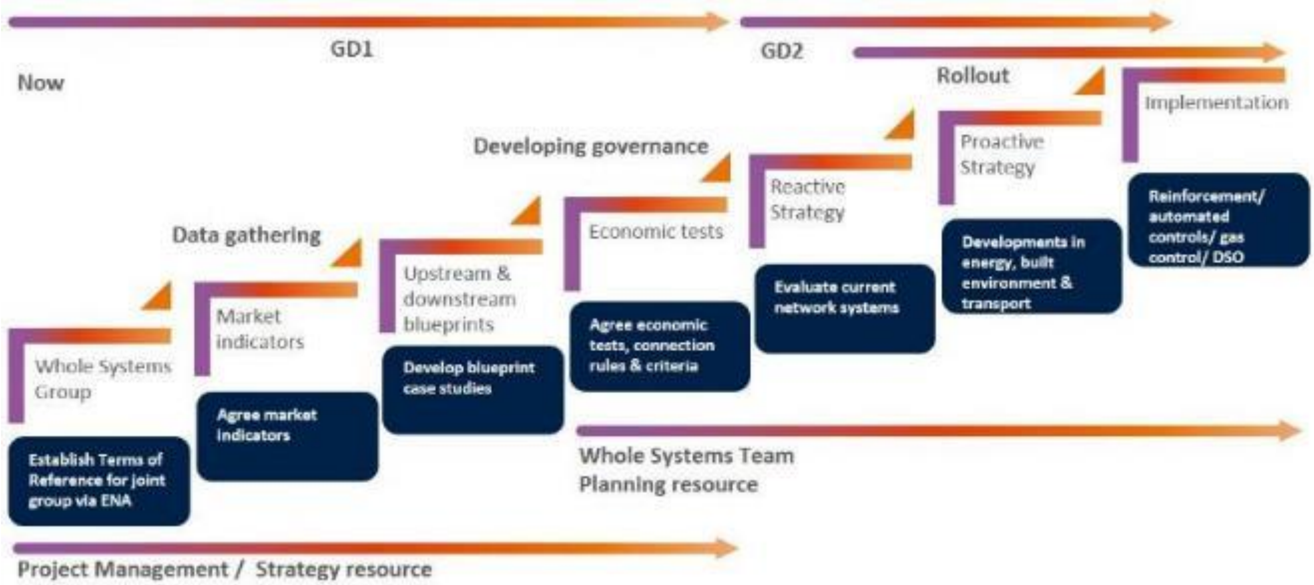
Energy systems and their networks are becoming increasingly interlinked, amongst themselves and in their impact on the wider economy. As the interaction between heat, electricity and transport become stronger, so too does the value of cooperation between the networks that deliver this energy. Improved coordination between network companies and system operators will ensure that more options are available to ensure that low carbon energy is delivered to the consumer at lowest cost.

Throughout GD1, SGN has worked closely with other parts of the energy system, in particular, gas transmission, electricity distribution operators (DNOs) and future DSOs, to improve operational interface across our shared network areas. Going forward, coordination will need to be stepped up to meet the challenge of net zero and changing customer needs and wants. This will require input from the four network sectors (transmission and distribution for electricity and gas) as well as the system operators (Electricity, Gas and Distribution).

Whole energy systems can deliver short- and long-term benefits to the GB energy consumer. Following extensive stakeholder engagement, SGN has developed a whole systems charter and portfolio of projects to ensure these benefits can be realised throughout GD2 and beyond. Our proposed charter has been further developed with the DNOs/DSO's in our footprint and shared with the ENA for wider rollout. It seeks to develop and exploit open data between energy systems and share progress with decarbonisation options allowing development of key interfaces and governance to advance dynamic whole systems planning.

Whole Systems Charter

Figure 1: Whole System Strategy



Creating a common set of structures for sharing information between local networks will be instrumental to creating an enduring whole systems approach during GD2. The challenge of decarbonisation is transporting renewable energy to every part of the whole system in a way that is reliable, safe, affordable and practical. Breaking down the barriers that currently restrict a whole systems integrated approach is a critical step in the achieving this.

Whole Systems Projects

The development of a 'Whole Energy System' approach is not only limited to the integration of the gas and electricity networks, transport is a significant user of energy and contributor to carbon emissions and air quality issues.

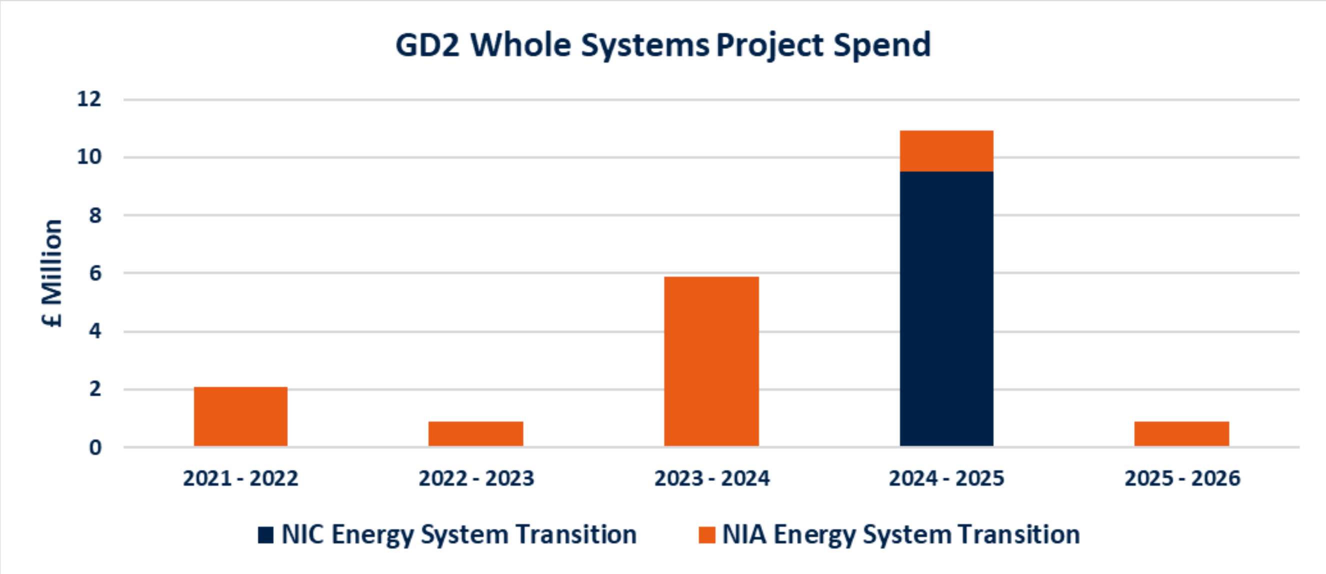
A large proportion of these projects are feasibility studies which will help identify optimal solutions to deliver net benefits to existing and future consumers in the relevant sector. The whole systems charter described above sets a helpful precedent for shared learning and process development with the power networks.

SGN has already gained experience working with some of the Government bodies responsible for transport system in the UK (Transport Scotland, Transport for London). This experience can be drawn upon and developed as gas, power and transport networks become more integrated. A more detailed description of our whole systems projects can be found in section 3.

Table 1: Project Summary

Project		Energy Transition Funding (£ Million)
Statutory Independent Undertakings (SIUs)	*Feasibility* *Demonstration*	0.1 5
Control Systems	*Feasibility* *Demonstration*	0.5 9.5
East Neuk – Power to Hydrogen for Fife		0.5
Operational and RT Information sharing protocols		0.2
Time of Use Tariff Impact Assessment (Real Time Networks)		0.1
Whole Systems Planning Tools		0.1
Local Authority Whole Systems Projects -selected from 135 councils		2
Demand Side Management		0.1
Gas to Power - Exercise to Determine Optimal Location for Peaking Plant Locations		0.3
Domestic CHP - Strategic Interventions (Gas to Power)		0.2
Strategic Temporary Units for EV Charging		0.2
H2 - Rail Network Transport Hubs		0.2
H2 - Ferries and Marine Transport Hubs		0.2
Optimising CNG exit for Road Fuel (Transport Fuel Solution)		0.2
Electrolyser Integration		0.2
Offshore vs Onshore Hydrogen Generation Regional Analysis		0.5

Figure 2: GD2 Whole System Project Spend



The project spend is predominantly made up of feasibility studies. This reflects the current nature of our energy system – made up of various elements working independently. The industry is changing rapidly. As our energy system transforms to tackle the challenges of decarbonisation, resilience and affordability, so the interactions between different elements of the system increase.

A significant increase in spend is anticipated in 2024/2025 as we move to the demonstration stage of our SIU and control systems projects.

1.2 Whole System Definition and Composition

Fundamentally, the energy industry exists to supply energy to satisfy a demand. UK whole system energy demand describes the total energy required to run every process in each sector. This includes everything from driving cars, heating homes and running industrial processes.

Traditionally, the majority of a sector's energy demand has been met by one fuel or energy vector delivered by one dedicated industry. This is largely due to the low price of that energy, the high efficiency which it is converted to useful energy and the low price and familiarity to consumers of the technology converting that energy. For example, the majority of heat demand is met by the gas sector supplying gas boilers and the vast majority of transport demand is met by the petrochemical industry, supplying combustion engines. Little interaction has been required between industries and as such little interaction has been established.

Meeting Demand

Different sectors have very different demand profiles. For example, transport and electricity demand are relatively consistent throughout a typical day and year, with relatively minor peaks and low ramp up rates in power requirements. Decarbonisation of flatter demand profiles is inherently simpler than the decarbonisation of peakier profiles. Power generation, be it low carbon or fossil fuel driven, is better suited practically and economically if it's output load is constant. A flat supply can match a flat, predictable demand without the need for substantial storage, and curtailment of excess generation is seldom required. **Figure 3**[1] shows the energy use in Scotland since 2013,

[1] Data from Scottish Government

which clearly shows transport and power demand is relatively consistent and flat, when compared to the demand for gas. Natural gas dominates heating, a highly challenging sector of the whole system to decarbonise.

The heat load, which is the largest duty of the gas network, is highly variable. On a daily basis it peaks as domestic and commercial heating systems start in the early morning, drops during the day and then peaks again in the evening. During the initial start-up, between 5 and 8am on a winter morning, the ramp rate is extreme with demand increasing by over 100GW over a period of 2-3 hours. This is illustrated in Figure 3 from a recent UKERC briefing note[2] for GB. This increase is approximnately 10 times the ramp rate which occurs in the electricity demand during this period. The whole system fundamentally demands more energy, far more unpredictably for heat than it currently demands for electricity.

Figure 3: Weekly Gas and Electricity Demand - Wilson et al.

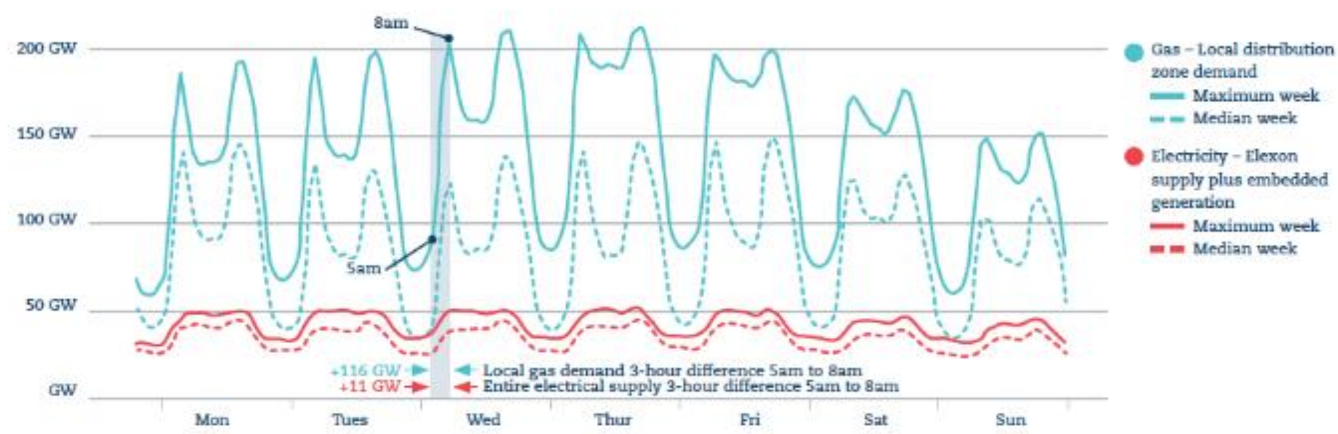
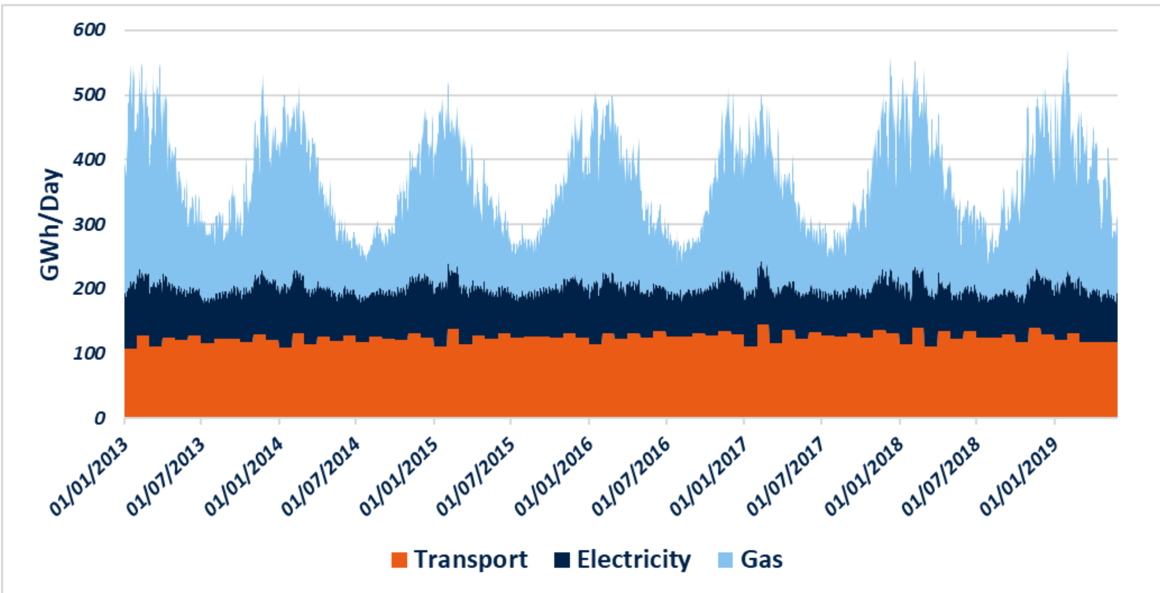


Figure 4: Scottish Energy Use



[2] Wilson et al. 'Challenges for the decarbonisation of heat: local gas demand vs electricity supply Winter 2017/2018' UKERC Briefing Note, 2018.

Figure 3 shows weekly gas and electricity demand at a national level. However, at the extremities of the network on a local level, the differences in peaks and troughs of gas demand will be greater. In the current market, the only vectors capable of transporting renewable energy are electricity and on a smaller scale, biomethane. There are a number of challenges which restrict the eletricity grid in delivering this energy to satisfy this load. The complex profile of heat demand is supplied relatively easily by the gas industry due to the ability store natural gas in large quantities through linepack overnight, which is released in the moring throughout the day to meet modelled demand.

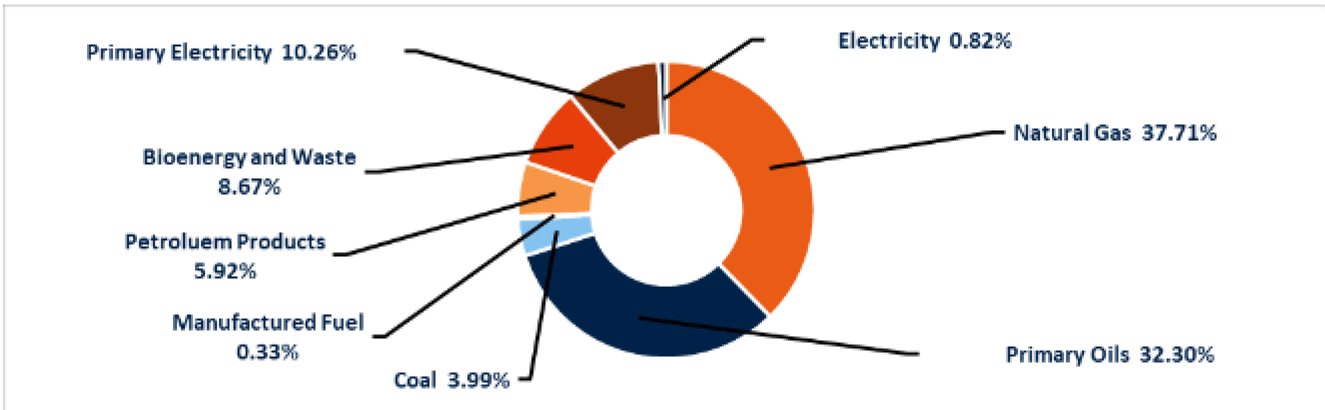
There is also a far larger seasonal swing with the average winter gas demand being 4-6 times that of the summer. In addition, the system is susceptible to even larger demand peaks during extreme winter cold spells. Note that figure 2 excludes gas used for electricity generation which accounted for over 50% of the power generation during this period and it covers the whole of GB.

Net-zero leglisation requires low carbon energy to supply all demands, and we believe this can only be achieved through an integrated whole system approach, particularly between the electricity and gas networks. We believe the decarbonisation of the energy delivered through the gas networks, through increased quantities of biomethane and the emergence of hydrogen as an energy vector will allow low carbon energy to be supply heat demand in a way that is most compatible with the energy trilemma.

Our Whole System Energy Supply

In 2018, the UK whole system demanded 2327.3 TWh of primary energy, the sources of this energy are shown in Figure 4[3]**.** Of this energy, 1659.9 TWh was used at the point of final consumption (by consumers), with the remainder lost to inefficiencies in conversion and transportation, used in the energy industry or used for non-energy purposes (e.g. feedstocks in manufacturing).

Figure 5: Primary Whole System Energy Sources



[3] Data from Digest of UK Energy Statistics 2019 – BEIS

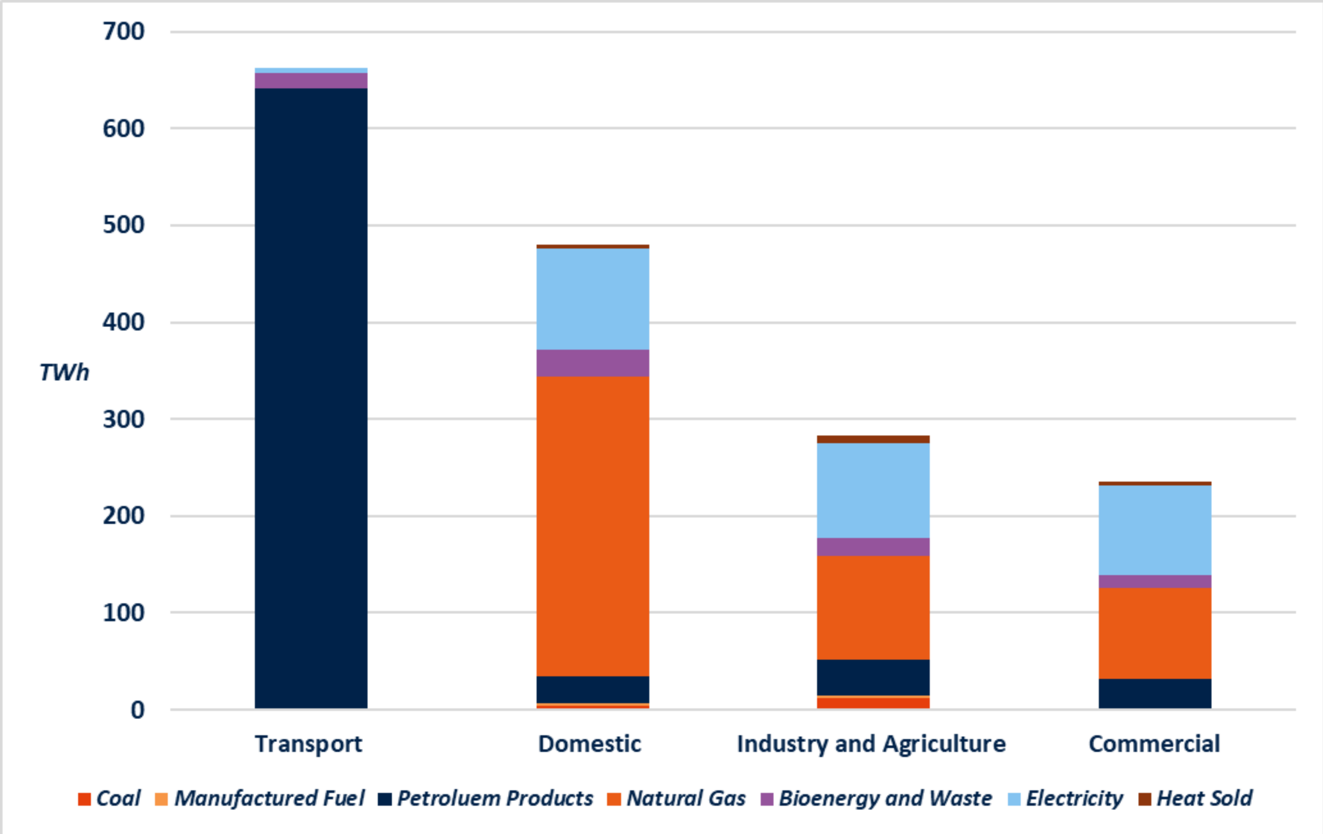
Figure 5[4] breaks down whole system energy use by sector and sources. It is clear that the majority of energy delivered by the whole system is derived from the chemical potential energy in fossil fuels (gas, oil and coal). Heat and transport demand the most energy of the whole system, and these two sectors are dominated by gas and petrochemicals respectively.

The majority of the energy used by the whole system is natural gas transported through gas transmission and distribution networks. In addition to heat,

The United Kingdom and Scottish Government's target of 'net-zero' carbon emissions by 2050 and 2045 respectively, is legally binding and globally critical. To achieve this target, the energy we as a wider industry deliver to customers and end users must be derived from renewable resources, biomass and waste, or carbon capture technology must be coupled with the use of any use of fossil fuels.

The UK has made significant progress in achieving climate change targets, with emissions in 2017 43% less than emissions in 1990. Decarbonisation progress has mainly been achieved in electricity generation, where more and more electricity is derived from renewables, and as such sectors which transform electrical energy have seen greater decarbonisation than those that do not. But there is significant progress to be made in decarbonising certain sectors of the whole system, which are inherently more difficult to decarbonise due to their reliance on fossil fuels, such as heat and transport.

Figure 6: Sector Specific Energy Demands and Sources 2018



[4] Data from Digest of UK Energy Statistics 2019 – BEIS

For example, heat demand and transport demand require significant amounts of energy very quickly, and the technologies which are the most dominant in their respective markets, are the most economical, technically mature and allow the most efficient use of fossil fuels as an energy source (e.g. gas boilers in the heating market). The challenge with decarbonising the whole system is ensuring renewably generated energy can be utilised by all parts of the whole system in a practical way which is secure and affordable.

Utilising energy from waste and biomass has the potential to drive deep decarbonisation of the whole system, the use of this energy must be maximised. But there will not be sufficient biomass or waste energy potential to supply all of the whole system energy demand. Renewable energy must become the dominant form of energy and at present, the only viable vector currently capable of transporting renewable energy is electricity. The disadvantage electricity has compared to fossil fuels is its energy density. Natural gas can deliver a much higher power than electricity and can be stored in significantly greater quantities at a far lower cost. Electricity does not have the same ability as gas to meet high peak demands (high power demands). This brings about challenges in increasing the use of electricity for processes with a variable high demand.

Storing Energy

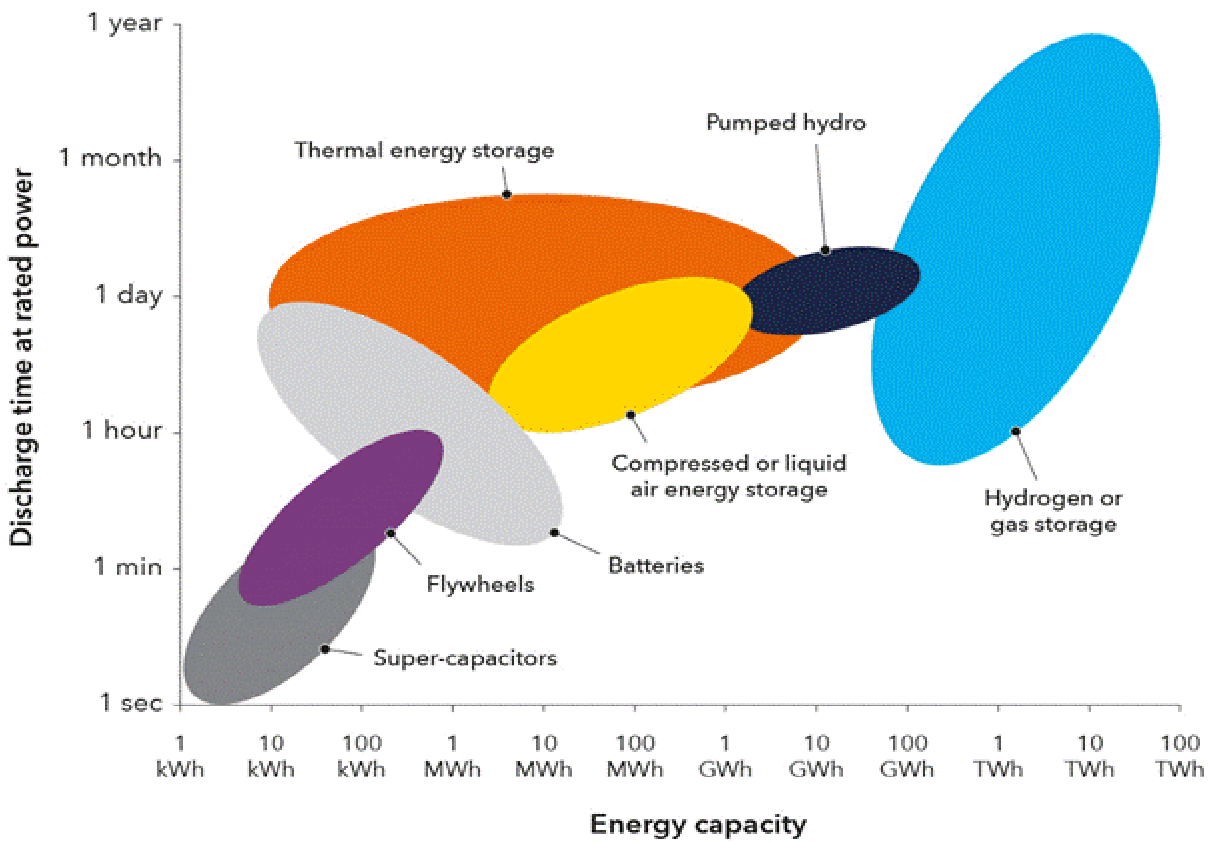
Renewable energy is only available when the energy of nature is present to harvest it, and the electricity generated must be used to supply a demand, otherwise it is wasted. A period of low renewable supply may occur during a period of high demand and vice-versa. Without the ability to store energy to meet high demands the whole system is not reliable and secure. Transporting renewable energy through the vector of hydrogen is an area of work gaining significant momentum due to the high energy density and ease of storage of hydrogen gas compared to electricity.

Figure 6[5] compares the energy density and discharge time of various energy storage mechanisms. To meet high peaks such as those seen in heat demand, significant storage is required for whole energy system security of supply and stability. This is met in the current market by the gas industry. Current storage mechanisms and technologies available to store electricity are an order of magnitude less energy dense than gas.

As more and more of whole system energy demand has been electrified, particularly with the accelerating uptake of electric vehicles, electricity networks are increasingly reliant on peak power generation, fuelled by gas, to balance the levels of variable generation being introduced into the power system. Indeed, as renewable electricity installations increase, decentralised gas fired peaking plants are replacing centralised base load power plants. Increasing uptake of electric vehicles will potentially impose significant new loads and variability to the electricity network, which in turn is likely to be transferred to the gas network in the form of peaking plants.

[5] Most cost and efficiency values from 'Electricity Storage Technologies – 5 Minute Guide' ARUP, 2014

Figure 7: Energy Storage Comparison



The 100 GW ramp up in GB heat requirements seen in the morning between 5-8 am would be much more difficult to manage on the electricity network which is used to far lower extremes of demand. Accommodating it would require the provision of much more peaking power plant capacity or large amounts of battery storage. The UK grid battery capacity was expected to reach around 500 MW in 2018 with the largest sites capable of delivering around 50 MW for up to an hour and are primarily constructed to take advantage of the Firm Frequency Response (FFR) schemes rather than provide prolonged electricity output. Growth in the battery storage sector is high at present, particularly for FFR, but the overall storage capacity is still small when compared to gas usage rates with a total of 9 GWh storage predicted by 2022. That storage is for minutes to hours, not days to weeks to months, which would be required for the heat load.

Indeed, natural gas and hydrogen are the only technologies which can currently be considered capable of providing significant energy storage at grid scale at reasonable cost.

As an example, the Storengy Stublach salt cavern site in Cheshire holds over 400 million sm^3 of natural gas and can deliver up to 33 million sm^3 per day to the gas grid. This is equivalent to 4,400 GWh of energy storage with a delivery capacity of over 15 GW. Were hydrogen to be stored instead of natural gas then these values would still be 1,350 GWh and 4.6 GW. At present, there are seven operating gas storage sites in the UK with a total capacity of 1.4

billion sm^3[6].

In practice, intra-day storage for the ramp up in energy requirements for the heat demand is easily met through line-pack. Total gas contained in the system typically varies from 335 to 355 mcm during the day[7], equivalent to approximately 220 GWh of energy storage capacity.

Battery Storage – 2018 National Renewable Energy Laboratory (NREL) study gives a cost for a 60MW/240 MWh lithium-ion battery installation as $91 million - $380 per kWh.

Hydrogen Storage - 2014 NREL study gives installed cost for small scale pressurised hydrogen storage as $1,350 per kg – equivalent to $35 per kWh (based on LHV).

Stublach gas storage site – reported CAPEX of £500 million for a storage capacity of 400 million sm^3

Were hydrogen stored instead of natural gas this would be equivalent to £0.38/kWh (based on HHV).

Challenges of Electrifying Heat

All energy demands must be met by low carbon energy, and the majority of low carbon energy is delivered through the electricity network. In terms of the decarbonisation of heat, heat pump technology, which utilises electricity and renewable ambient heat, is gaining momentum in penetrating the marketplace. Heat pump technology undoubtably will play a role in the whole energy system of the future. But we have some concerns over the narrative often seen, that to decarbonise heat all gas boilers in the land can be simply replaced by air source heat pumps or hybrid heat pumps. During the period, we intend to work with DNO's and manufacturers to overcome the challenges we have outlined in this section.

One of the main marketing drivers of heat pump technologies is their coefficient of performance (efficiency), which can exceed 300% when the ambient temperature is high enough. The fundamental drawback of the principle behind an air source heat pump is that as the ambient temperature decreases, the refrigeration energy demand increases. In effect the very renewable resource an air source heat pump harnesses diminishes as the demand for heat increases. This results in the coefficient of performance decreasing during times of peak demand.

In addition to this, heat pumps radiate heat at a far lower temperature than conventional gas boilers, they therefore require a larger area to radiate this heat to maintain the equivalent heat flux of a conventional gas boiler. This can often require underfloor heating, which is expensive and disruptive to retrofit to existing properties and sometimes not at all possible in the case of some property types, such as small flats, which comprise a high proportion of the UK housing stock. Heat pumps for household use are a relatively new technology and are therefore more expensive to buy and run for customers. Whilst this will come down over time, time is not on our side in the decarbonisation of the whole system. And customers will not accept a highly disruptive and expensive technology.

As part of our NIC funded Real-Time Networks Project, we have set out in partnership with DNV GL, to develop a demand model capable of giving a "real-time" view of network performance. The vast majority of the gas

[6] National Grid Gas Ten Year Statement, 2018.

[7] National Grid 'Gas System Operator, Operational Overview' 2018

transported through our network is used to provide energy for heat, through gas boilers, which currently dominate the market. The Real-Time Networks demand model must be sufficiently flexible to model the heating market demand as it is today and consider how the market may change as we seek to decarbonise heat.

The success of downstream renewables in the market will have a direct impact on gas demand in the future. As such, it is essential their performance across various scenarios be better understood. Through our Real-Time Networks project, we, in collaboration with DNV GL and Kiwa Gastech, have completed laboratory testing of various downstream renewable technologies to assess their performance when tasked with meeting the demand of different load sizes, profiles and conditions.

This was made possible by the use of Kiwa's Dynamic Heat Loss Test Rig and Domestic Hot Water Test Rig. This laboratory setup was able to repeatably and reliably simulate a wide range of conditions in a property. Variables tested were the heat load size, radiator temperature, ambient environmental conditions and the demand profile type (i.e. continuous, bimodal or unimodal load). While this testing can never truly mimic practical operation, it does give a solid insight into how these technologies perform over a variety of conditions.

Figure 8: High Level RTN Downstream Renewables Testing Results and Findings

The tested technologies were a gas combi boiler, an air source heat pump, a hybrid ASHP/gas boiler unit, a gas fired air absorption heat pump and a micro combined heat and power boiler

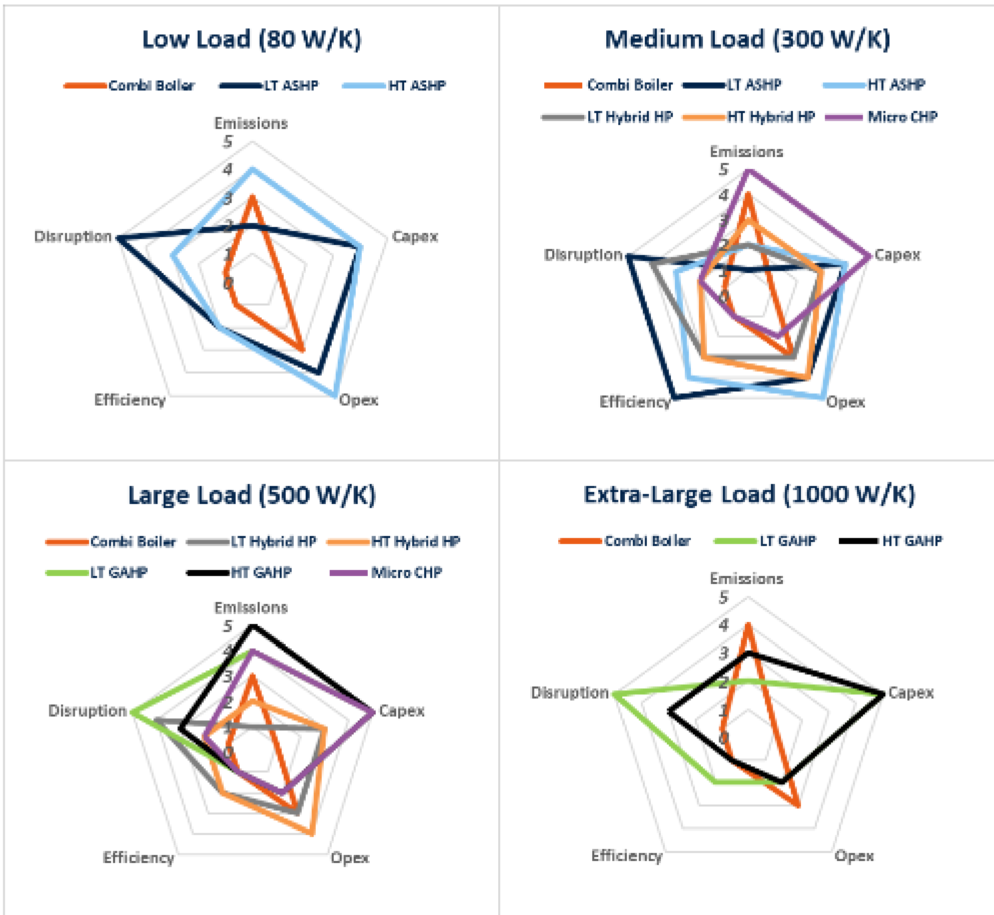
All downstream renewables were compared in testing to the performance of the gas combi boiler. The full details and results of the testing are contained in the Real-Time Networks project reporting[8]. High-level results of the testing and the conclusions drawn are shown in **Figure 7**.

To maximise the value of the testing, the results were analysed, and further comparisons were derived in both

[8] Real-Time Networks SDRC 9.7. Assessment of Relevant Renewable Technologies Impact on the Network

thermodynamic, human and financial factors. The technologies were compared against one another in terms of carbon emissions, relative disruption to customers, efficiency of operation, capital expenditure and operation costs in differing load conditions. These results are shown in **Figure 8** and can be interpreted as 1 being low and 5 being high.

Figure 9: Comparison of Tested Technologies



Overall, in the case of this testing, the natural gas combi boiler provided the optimal heating solution to each load size. In most cases, due to the carbon intensity of the grid at the time, natural gas boilers provided the cleanest heating solution, however it should be noted that heat pumps enable the use of renewable energy, traditional gas boilers do not. The installation of heat pump technologies was concluded to be highly disruptive and expensive compared to the gas boiler, this is not compliant with the energy trilemma and as such any efficiency gains from using heat pump technologies are offset by this. Many downstream renewable technologies are in their infancy compared to gas boilers, and their performance is expected to improve. What this testing has shown us however is the concept of burning a chemical energy source in a boiler is currently the most compatible, affordable and practical way of heating a space. The use of hydrogen gas in a boiler as an energy vector of renewably generated energy presents a possible way of delivering clean energy in the same way as natural gas, without the emissions, but with the least disruption and cost to customers.

In terms of decarbonising heat, an analysis of the whole system for heating demand is required to optimise local solutions. Every region and type of property may have a different solution and there will never be a one-size-fits-all for GB customers and stakeholders.

The Challenges of Decarbonising the Transport Sector

Another significant challenge is in the decarbonisation of the transport sector, and an integrated whole system approach is essential if net-zero compliance is to be met in a way most affordable and least disruptive to customers. The increasing electrification of transport has brought about an increasing interplay between gas and electricity, which will increase substantially at the current trajectory.

The transport sector demands the largest quantity of energy from the whole system, and the vast majority of this energy is derived from petroleum products. Kerosene is the only fuel used in aviation, and petrol and diesel are used to power the great majority of road vehicles. A significant number of trains are powered by diesel. Bioenergy in the form of biomethane is used to power some transport, mainly in haulage. Electricity is used to power a small proportion of automobiles, mainly cars, and approximately half of GB train network traffic.

The transport sector is undergoing significant changes. Electric vehicles (EVs) are gaining substantial momentum in penetrating the marketplace, with 219,000 electric vehicles now on Britain's roads as of June 2019[9]. EVs are more efficient than internal combustion engine vehicles, resulting in a reduction in transport energy demand, and they enable the use of renewable energy in the transport sector by storing electrical energy in lithium-ion batteries.

Despite this however, the electrification of transport presents a significant challenge to the wider whole energy system. The overall transport demand of the whole system significantly eclipses the current overall electricity demand. If electricity from renewable sources is to supply the majority of our transport demand, then it must be be significantly increased. There is a danger that the ramp up in generation capacity and the necessary reinforcement of power grid to deliver this energy may struggle to match the rate of electric vehicle uptake.

The marketing drive behind the electric vehicle revolution is the fact it can deliver clean energy to the transport sector. But there must exist the capacity to supply this energy from carbon-free resources if this is to become a widescale reality. If this does not happen, there is a danger that the emissions of the transport sector may simply be pushed back in the supply chain to power generation from fossil fuels. There is a potential supply gap which will need to be met by the capacity market, likely though gas peaking plants, which do not boast particularly high efficiencies. This has been seen, to an extent, already by SGN though a rapid increase in the number of requests for connection of gas peaking plants.

The shift of such a high proportion of our current demand to electricity is a challenge the whole system must fully understand and appreciate the scale of. One of the main conveniences of owning a car is the ability to travel anywhere at any time. If the electricity supply and infrastructure delivering it is not sufficient, peak shaving/shifting approaches such as vehicle to grid may be required, with Time of Use Tariffs (TOUTs) becoming necessary. This may erode the freedom associated with owing a car and the control of demand may be unacceptable to many customers.

EVs are highly likely to dominate the light vehicle transport sector moving forwards, as in the current market, they provide the most affordable method of road travel using electricity. Consideration must be given however to hydrogen vehicles. Petrol and diesel are highly compatible with transport in that they are a relatively cheap, energy dense resource which is used in a technology which is mature and affordable. Hydrogen is also energy dense, and as such hydrogen cars are increasing globally, especially in Asia. The most challenging barrier to hydrogen cars is the price of the car itself, the price of the fuel. Advancements in fuel cell technology are projected to bring the capital cost of the car down, and the presence of a hydrogen distribution network will drive down the price of hydrogen. The main advantage a hydrogen vehicle has over an EV is the time to refill. Both technologies undoubtably will play a key role in the decarbonisation of the transport sector.

[9] Next Green Car – Electric Car Market Statistics - https://www.nextgreencar.com/electric-cars/statistics/

The Challenges of Decarbonising Industry and Agriculture

In the UK in 2018, Industry demanded 17% of final energy[10]. The majority of energy delivered to industry and agriculture is through fossil fuels – natural gas, petroleum products and coal with just under a third delivered by electricity. The industrial and agricultural sector is highly varied and diverse, with multiple types of industrial processes, from foundries, chemical processing plants, manufacturing, textiles, food and beverage production to name a few.

Due to this variety, industry is highly challenging sector of the whole system to decarbonise. Many processes in industry have very high power and heat requirements and are highly sensitive to the price of this energy. Some processes require high temperature heat, which cannot be supplied electrically. For this reason, electrifying many industrial processes will not make practical or economic sense as electricity simply cannot deliver this energy quickly enough in the current infrastructure. A solution to decarbonising industry is potentially the continued use of fossil fuels with carbon capture technology. Industry often exists in clusters, boosting the case for CCS technology if appropriate to the region, e.g. Teesside and Aberdeen. Hydrogen also provides a potential solution to decarbonising industry, due to its similar energy density to natural gas.

Figure 10: Extract from our Methilltoune Project

Agriculture is perhaps the most challenging area of the whole system to decarbonise due to the fact a significant proportion of emissions come from livestock. Carbon offsetting is a likely solution to decarbonising agriculture, as well as biogas production from waste products.

The complexity of industrial decarbonisation cannot be understated. Understanding how each industry and their respective energy supply interact is critical in developing a whole energy system with the capability and flexibility to provide optimal decarbonisation solutions to every sector of the whole system. **Figure 9** outline how we are engaging with Diageo as part of our Methilltoune project[11].

As part of our Methilltoune project, SGN have opened dialogue with Diageo who have a large presence in Levenmouth attributed to their bottling plant and Cameronbridge Distillery, who are a large employer of the local area. Diageo have a high energy intensive carbon footprint based on their requirement for space heating and process distilling. This is currently served by natural gas. Diageo have offered a letter of support for our Phase 2 bid to represent this growing and opportunistic engagement and could service their requirements in future phases.

[10] DUKES 2019

[11] Methilltoune Final Report, October 2019

2 Breaking Down System Boundaries

The GB gas and electricity networks have evolved separately but they can be integrated to offer a low-cost route to decarbonisation. Feedback from stakeholders was clear that they wanted us to do more in terms of the 'Whole Energy System' and we have taken steps to move this forward into RIIO GD2.

For decades, the UK's gas and electricity networks have operated largely as discrete systems. Those touch points that did exist were gas-fired generation plants operating primarily at transmission level. Similarly, within the gas and electricity sectors, interfaces between transmission and distribution were relatively simple, with both sectors designed to operate in a 'top down' configuration with energy flows from high to low voltage and pressure respectively.

This plannable, steady state paradigm is rapidly changing in what is becoming known as the energy transition. System boundaries, that the industry has known and understood for decades, are blurring due to the accelerating need for decarbonisation and the opportunities presented by digitalisation. The simple system boundary concept was reflected in regulatory boundaries and licences – these too are now having to be rethought. The opportunity now exists for networks to consider how best to deliver maximum decarbonisation and system interoperability in the most efficient possible manner.

There are already established processes to manage coordination between Gas Transmission and Gas Distribution and, while these could always be improved, wholesale change is not required. For example, the capacity incentive mechanism included in RIIO GD1 has resulted in marked behaviours from the GDNs to book network capacity at under-utilised, and hence lower-cost offtakes, lowering investment costs for the Gas Transmission system. We welcome the proposed continuation of the NTS Exit Capacity Incentive in RIIO GD2.

There is an opportunity for significant improvement in coordination and planning between Gas Distribution and Electricity Distribution networks over RIIO GD2, specifically with respect to the growth in distributed gas generation capacity and large exit connection planning.

The electricity system has historically been characterised by large, dispatchable power stations (largely fossil-fuel fired) connected to consumers by a transmission network and local distribution networks. Demand and supply have both been largely predictable and power trading and system balancing have been dominated by long term contractual arrangements, with short-term price signals having little impact on most network players.

The gas system has evolved, and continues to evolve, with the advent of embedded entry/distributed injection of renewable gas into the distribution networks.

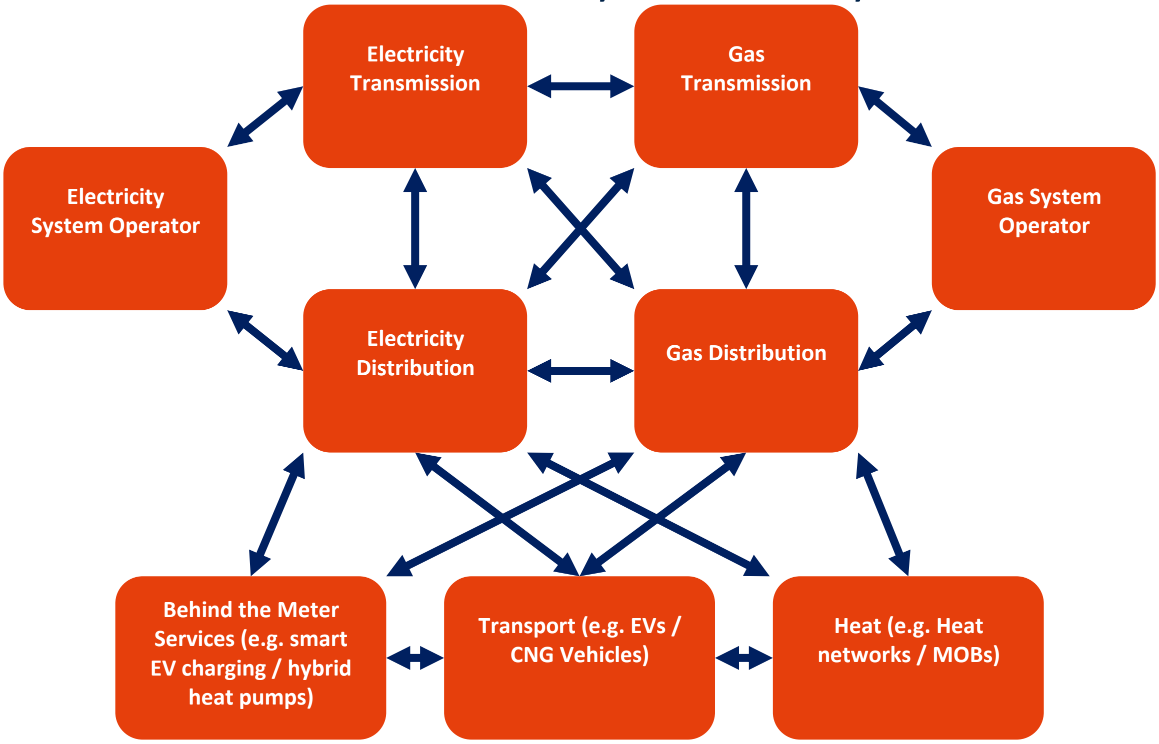
The electricity system has, even in the last five years, seen considerable change. Driven by climate change policies, coal-fired power generation has largely disappeared (and will be completely removed by the end of the next price control period) and has been replaced by intermittent renewables connected at both distribution and transmission level. This has resulted in a power system which is harder to control (both in terms of matching supply and demand, but also in managing system requirements such as frequency) and which is more volatile in terms of reliance on short-term price signals.

This change in the electricity system is now starting to impact the gas system, coupling what have been, up until now, largely separate systems. To manage short term supply and demand, a market is in place which has incentivised the construction of 'peaking plant'; that is power generation assets that are used intermittently and at short notice. The lowest cost assets in this class are gas-fired generators, usually reciprocating engines connected to the gas distribution networks, which have the effect of translating peak electricity demand into additional gas demand. While some of the market arrangements that incentivise the construction of these assets have recently been scaled-back or suspended, the underlying system requirement will continue to grow.

We foresee this trend continuing over the GD2 price control, leading to a growing interplay between electricity and gas systems, a greater coordination of operation and investment planning and, by 2030, a substantially integrated energy system being in place.

There is also significant potential for energy system transition behind the meter (BTM). How networks interface with activities BTM, develop understanding and processes to manage and facilitate the various technologies, is likely to be an essential element of driving customer value in RIIO GD2. Further interaction between gas and electricity networks is likely to evolve BTM through the increasing development of heat pumps and hybrid heat pumps, which seek to optimise either consumer cost, or carbon emissions (or some combination) through smartly switching between gas and electric modes depending on pricing signals and carbon intensity. Looking to the future, there are growing aspirations to convert surplus renewable electricity, that would otherwise be curtailed, into hydrogen for injection into the gas grid in a process known as power-to-gas.

Figure 11: How we define the sectors of the whole system and how they interact



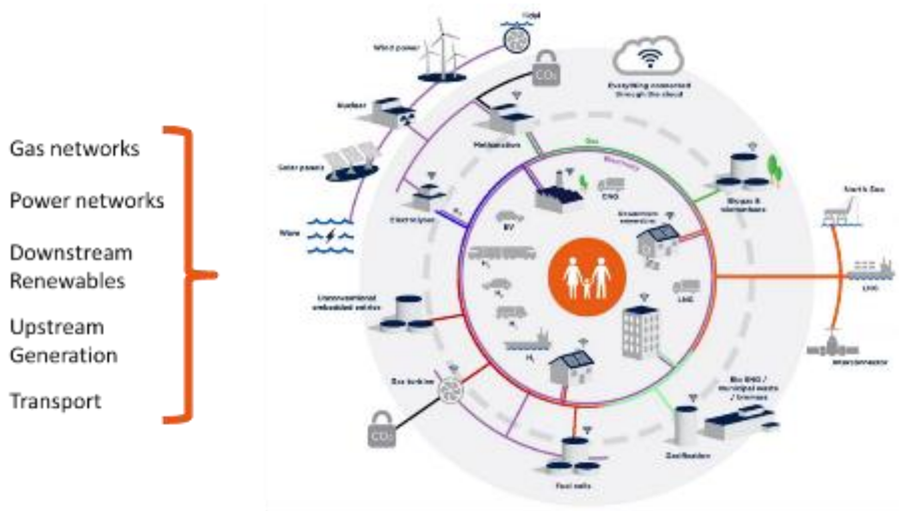
The UK has a great wind power potential, particularly off the coast of Scotland. But renewable generation from wind is intermittent and the export and storage of excess wind energy is problematic. The gas network has significantly higher capacity for energy delivery, provides flexible storage and could thus be used to maximise the benefits of renewable energy. Long distance delivery of large quantities of energy is better suited to the gas network and molecules provide the longest storage potential.

Future changes to the Power sector may have a significant impact for our gas network. Under the Distribution System Operator (DSO) model, the operator will take a more active role in managing local electricity generation and use. Specifically, the DSOs will securely operate and develop an active distribution system comprising networks, demand, generation and other flexible distributed energy resources. The impact of this is unknown, but indications from the capacity market suggest that gas will play a more localised role as generation of power is decentralised.

When developing a 'Whole Energy System' approach it should not only be limited to the integration of the gas and electricity networks, transport is a significant user of energy and contributor to carbon emissions and air quality issues. With both UK and Scottish governments indicating their wish to phase out petrol and diesel road vehicles alternative sources of energy for transport need to be introduced. The expectation is that electric vehicles (EV) will dominate road transport in the future, with some compressed natural gas (CNG) and hydrogen fuel cell vehicles.

Other areas of the transport sector are also looking at alternative fuels, the development of hydrogen fuel cells for rail and marine transport is already underway and Liquified Natural Gas (LNG) could play its part in fuelling other marine vessels. For all these areas, the step away from traditional fossil fuels will mean a greater interaction with the gas and electricity networks. Transport could be an early user of hydrogen stimulating the market and the transportation of hydrogen within the gas network. For EV's there will be, as previously discussed, a need for more decentralised generation due to the intermittency of renewables as the volume of vehicles and therefore electricity demand increases.

Figure 12: Whole Energy System



This integration is underway, but both gas and electricity networks and the transport sector need to evolve further to deliver higher levels of decarbonisation. We therefore propose to develop and explore a wider 'whole system' definition and believe the mechanisms proposed will allow us to do so. To support this ambition, we have developed a 'Whole system charter' with the power networks in our geographic area - UK Power Networks, Scottish Energy Networks and Scottish and Southern Energy Networks - to draft a charter that sets out a series of commitments defining how we will work together during GD2. These include:

1. **We commit to developing and sharing a set of market indicators that improve GDN/DNO ability to forecast gas and power demand.**
2. **We commit to holding a joint annual review to share planning assumptions prior to publication of our respective statements.**
3. **We commit that during RIIO-2, we will develop a joint scenario planning process to be used for the RIIO-3 Price Control.**
4. **We commit to share our annual investment plans for those assets with whole system implications, including network reinforcements to support gas-fired generation assets, large load connections and any other assets that bridge the interface between gas and electricity.**
5. **We commit in RIIO-2 to developing a large load connection process across the GDN / DNO boundary to help customers secure the energy connection best suited to their needs, at the lowest cost to them and the wider network.**
6. **We commit to working together in RIIO-2 to develop and implement an operational planning, information sharing protocol.**
7. **We commit to developing a trial mechanism in RIIO-2 for sharing real time operational data for**

assets of common interest, primarily gas-fired generation assets.

8. **We to exchange early information between the GDN and DNO on scale, location and likely duration of any substantial gas or power network outage to allow system impact planning to minimise customer disruption.**

We believe that creating this common set of structures for sharing information between local networks will be instrumental to creating an enduring whole systems approach during GD2. The challenge of decarbonisation is transporting renewable energy to every part of the whole system in a way that is reliable, safe, affordable and practical. Breaking down the barriers that currently restrict a whole systems integrated approach is a critical step in the achieving this.

3 Whole Systems Projects

3.1 Whole Systems R&D

The development of a 'Whole Energy System' approach is not only be limited to the integration of the gas and electricity networks, transport is a significant user of energy and contributor to carbon emissions and air quality issues. We have developed a portfolio of research and development projects that will demonstrate the benefits of whole systems solutions throughout GD2.

Table 2: R&D Projects

Project	Description and Relevance	NIA Energy System Transition (£ Million)
CNG and LNG Vehicle Connection Strategies	R&D into optimised and simplified CNG connections including generic PS8	0.2
Operational and RT Information sharing protocols	Development of optimised information interface	0.2
TOUT Impact Assessment (RTN)	Assessment of the impact of time of use tariffs to reduce demand in whole system	0.1
Whole Systems Planning Tools	Development of tools and methods to plan whole system strategy	0.1
Local Authority Whole Systems Projects -selected from 135 councils	Need for regional studies to provide optionality in local government/authority areas	2
Demand Side Management	Research and demonstration of dual gas/electric fuel switching applications and demand side management	0.1
Gas to Power - Exercise to Determine Optimal Location for Peaking Plant Locations	Research and demonstration of strategic peaking plant with DNO/DSO	0.3
Domestic CHP - Strategic Interventions (Gas to Power)	Research into CHP technologies and their ability to facilitate cross sector solutions for energy system balancing and demand forecasting	0.2
Strategic Temporary Units for EV Charging	Research into whole system solutions for electric vehicle recharging	0.2
H2 - Rail Network Transport Hubs	Studies for local government and local authorities to optimise the transport system interface and how we can facilitate	0.2
H2 - Ferries and Marine Transport Hubs	Studies for local government and local authorities to optimise the transport system interface and how we can facilitate	0.2
Optimising CNG exit for Road Fuel (Transport Fuel Solution)	Research into minimising entry costs and demand management	0.2

Electrolyser Integration	Defining the role of the electrolyser in a hydrogen system for blending for conversion	0.2
Offshore vs Onshore Hydrogen Generation Regional Analysis	Development of the optimal network entry for production of hydrogen from onshore or offshore wind generation	0.5

3.2 Machrihanish Whole System

Machrihanish, located near the tip of the Mull of Kintyre, is the second site currently under review for the H100 project. Machrihanish has an abundance of renewable generation located within the vicinity of the site but is remote from existing gas infrastructure. The H100 demonstration project would involve the construction of a hydrogen grid to serve Campbelltown Airport business park and approximately 300 domestic and small commercial users in the south of the Mull of Kintyre. Key advantages of the Machrihanish location are:

- This option would link to the existing Statutory Independent Undertaking at Campbelltown, an isolated network well suited for renewable gas injection and offering the possibility of future expansion.
- The Mull of Kintyre has many nearby options for windfarm or tidal power generation which could be realised for electrolysis based green hydrogen production.

Figure 13: Campbelltown Airport Business Park

This project, starting in 2021, would look to fund the construction of a 100% hydrogen network in GD2, to domestic and commercial premises currently supplied by electricity, but include in its customer value proposition the option to install a heat pump. The use of standalone heat pumps or smart hybrid system and 100% hydrogen boilers would provide a comparison of the different technologies available to consumers in remote off grid communities.

Benefits

The H100 Machrihanish project has the potential to set the agenda for greenhouse gas reduction by evidencing how hydrogen can be safely and securely delivered through a piped network to homes, aligning this with other low carbon solutions for heating to give an accurate comparison of technology operation for a whole energy system solution. The site will be at the forefront of developing business models that support the future commercial viability of hydrogen production and distribution.

Phase	Timing	Funding Mechanism	Amount (£ Million)
Detailed Design	2021 – 2022	NIC Energy System Transition	1.0
Construction, Commissioning and Operation	2021 – 2026	NIC Energy System Transition	14.0

3.3 Statutory Independent Undertakings (SIUs)

Figure 14: SIU's locations

Our Statutory Independent Undertakings or SIUs are located in 5 towns across the north and west of Scotland and are not directly connected to the main natural gas network. These independent networks are supplied with either Liquified Natural Gas (LNG) or Liquefied Petroleum Gas (LPG) as indicated below, which is delivered by road tanker to the SGN gas facility within the town. These networks provide excellent statistically representative systems, as demonstrated in our Opening up the Gas Markets project and the follow-on work at each of the mainland town.

SIU Location	Gas Source
Oban	LNG
Campbelltown	LNG
Wick	LNG
Thurso	LNG
Stornoway	LPG

These networks offer an opportunity for the roll out of decarbonisation technologies to a consumer base of nearly 10,000 meter points. Blending 20% hydrogen, where possible, into all gas supplied to the towns would reduce carbon dioxide emissions and this could be supplied from fully green hydrogen, utilising the renewable generation from wind which is predominant in these areas. An alternative option would be to fully decarbonise the networks in these towns with 100% hydrogen, using the learning from the H100 trials and demonstration. This could see in the region 50,000 tonnes of carbon removed from emissions per year.

The establishment of hydrogen infrastructure in SIU's offers various potential opportunities to decarbonise transport. This may include uptake of fuel cell vehicles for public and private transport. Wider transport decarbonisation using hydrogen may be achieved with fuel cell ferries, and the possible linkage with rail services using fuel cell trains.

Our proposal in GD2 will be to undertake a feasibility and FEED study for each of these towns to ascertain the most economical way to decarbonise the gas network in each using hydrogen. This will involve close coordination with the local community.

Benefits

In addition to reductions in CO_2 emissions and improvements to air quality, customers in these areas could benefit from the development of a hydrogen economy in their local area. The learning developed throughout the H100 project could be used in this project to take us further along the gas decarbonisation pathway.

Phase	Timing	Funding Mechanism	Amount (£ Million)
Feasibility Study	2021 – 2022	NIA Energy System Transition	0.1
Demonstration Site Construction	2023 - 2024	NIA Energy System Transition	5

3.4 CNG and LNG Vehicle Connection Strategies

CNG vehicles uptake in GB has been relatively low but use of natural gas has the potential to offer significant improvements in air quality and, as the gas grid is decarbonised, increasingly lower carbon emissions for some classes of vehicle that may otherwise be difficult to decarbonise. Use of CNG or LNG as a vehicle fuel may also offer a route to market for otherwise hard to connect sources of unconventional gas or biomethane.

This work would identify, new approaches and initiatives to grow the use of gas in vehicles through innovative connection strategies.

Benefits

Improved air quality and carbon reduction from CNG and LNG connections are a clear benefit to customers. A more diverse route to market for biomethane producers will also contribute to our objective of providing 10% capacity improvement for embedded entry injection.

East Neuk – Power to Hydrogen for Fife Following on from our RIIO GD1 NIA study of hydrogen from renewables in the East Neuk study we will develop an East Neuk Hydrogen pilot project during GD2.

Figure 15: East Neuk Schematic

Our proposed pilot would involve a combination of investments and allied service offerings, including hydrogen

refuelling stations, a fleet of FCEVs and a newbuild hydrogen grid to 300 homes (or possibly conversion of a section of existing natural gas grid). The newbuild hydrogen grid may be an extension to the H100 grid proposed for Levenmouth.

Benefits

The use of curtailed renewable energy to produce hydrogen is a way of increasing the amount of renewable energy. This has clear benefits to customers in terms of air quality, decarbonisation and reduced payments to curtailed renewable electricity generators. Closer collaboration between GDNs and DNOs will lead to a more cost effective, resilient network and ultimately benefit the GB energy consumer.

Phase	Timing	Funding Mechanism	Amount (£ Million)
Feasibility Study for Full East Neuk 100% H_2 Conversion	2024 – 2025	NIA Energy System Transition	0.5

Control Systems

The increase in intermittent renewable electricity generation and shift from coal fired generation has led electricity system operator, National Grid to purchase an increasing volume of 'ancillary services' to help manage the electricity system. These services are increasingly met by small, distributed gas-fired generators amongst other forms of fast acting generation.

The changing nature of our energy system provides an excellent opportunity for gas and electricity networks to work more closely to optimise customer outputs. Currently there is no mechanism for sharing real-time operational data between GDN and DNO control rooms. Few distributed gas-fired generation assets are SCADA connected to the GDN control rooms, meaning they have limited visibility of when these assets are being used. Real-time visibility of local system management could be used to optimise flows and system pressures and to provide better offtake profile notices to the Electricity System Operator.

Our proposed project will investigate areas where there is a lack of coordination between gas and electricity networks and how instrumentation and communications systems can be developed for whole systems optimisation.

Phase	Timing	Funding Mechanism	Amount (£ Million)
Feasibility Study	2021 – 2022	NIA Energy System Transition	0.5
Demonstration	2024 – 2025	NIC Energy System Transition	9.5

Benefits

Improved controls and coordination with local electricity distribution system operators builds upon our work towards whole systems solutions. These solutions will result in more efficient gas and electricity networks, improving system security and reducing cost to customers.

4 Enabling Whole Systems

To explore the landscape of a 'Whole System' more systematically, a system's engineering approach has been adopted, framed largely around the Future Power System's Architecture (FPSA) project[12].

Scenario planning is based on National Grid's Future Energy Scenarios (FES) 2018[13]. All four scenarios in the report (Community Renewables, Two Degrees, Steady Progression and Consumer Evolution) see a role for gas in 2050. However, only two of the modelled scenarios achieve the current 2050 emissions reductions targets, namely Community Renewables and Two Degrees.

For Network Planning purposes, the Gas Distribution Networks have until now used the Steady Progression scenario as this is most representative of the evolution in network demand that has been seen over the last few years. However, there are elements of the other scenarios that merit further attention, as, while they may not form the basis of today's network planning, they will require networks to develop processes to deal with uncertainties.

4.1 Timescales and Drivers of New Functionality

The FPSA project identified four timescales for categorising functional requirements of a whole system approach:

- Investment Planning – typically three or more years ahead of commissioning new equipment. Examples for Gas System planning could include expanding the capacity of an AGI (Above Ground Installation), or a pipe reinforcement project.
- Operational Planning – typically a few days to a couple of years ahead. Examples for Gas System planning could include the annual offtake booking process, or the flexible, day ahead market.
- Real Time and Balancing – on the day operation of the system. Examples for Gas System operation could include the management of Biomethane entry sources or system storage.
- Settlement and Market – Post real-time, typically over a period of weeks. Examples for Gas System operation could include the settlement of gas billing based on reconciliation of real-time network SCADA metered data and Xoserve data.

Using the FPSA as a basis, the following drivers of new gas system functionality have been established to accommodate whole system thinking, these are the required changes to the way the gas industry functions to facilitate and enable the development of a whole system approach to energy modelling and management:

Flexibility to meet changing but uncertain requirements

the FES scenarios all foresee a future role for gas, and hence gas networks, but there are major differences in many aspects of the scenarios. Gas networks and their supporting planning processes need to be sufficiently flexible to accommodate wide variations in forecasts for electric vehicles, heat pumps, transport demand etc. To enable this flexibility, we believe the following functions must be developed under the following timescales:

- Investment Planning - Develop rapid system planning tools to ensure full dynamic effects of new connections and flow scenarios can be assessed and connection offers made in a timely fashion.
- Investment Planning - Develop scenario planning tools that model, on a geographic and dynamic basis, the impacts of whole energy system transformation on the gas network (e.g. development of PathFinder).

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[12] IET and Energy Systems Catapult. (2017). Future Power Systems Architecture. Catapult. Retrieved from https://es.catapult.org.uk/publications/power-system-architecture-fpsa-full-report/

[13] National Grid. (2018). Future Energy Scenarios. National Grid. Retrieved from https://fes.nationalgrid.com/media/1363/fes-interactive-version-final-pdf

Change in mix of gas sources

Historically, gas has flowed into the transmission network from import terminals (either UKCS production, interconnectors or LNG imports) and then cascaded down the pressure tiers. There are now 80+ distributed biomethane connections on the gas distribution networks, with future entry connections also planned for shale gas and bioSNG (methane from gasification of bioenergy feedstocks). This evolution in the source of gas is already requiring networks to be configured in unorthodox ways, whilst fundamental underpinning regulations, such as Gas Safety (Management) Regulations (GS(M)R) and the Calculation of Thermal Energy Regulations (CoTER) will need to be flexible to accommodate these changes. To ensure the gas network is able to function as part of the whole energy system with greater variety in sources of gas, the following functions must be developed under the following timescales:

- Investment/Operational/Real-Time - Establish tools for better understanding gas flows in the network to provide basis for billing changes (e.g. development of Real Time Networks project and subsequent analysis)
- Investment/Operational/Real-Time - Establish active network management systems to minimise network constraints, and hence maximise commercial returns of network actors (e.g. development of Real Time Networks)

Change in Mix of Electricity Generation

The rise in intermittent renewables is leading to a significant growth in distribution-connected power generation, potentially leading to a growth in peak demand. Understanding of this dynamic and its impact on the network is essential in future network planning. To enable this understanding, the following functions are required to be developed under the following timescales:

- Investment - Establish information exchange mechanisms with GDNs / ESOs (Electricity System Operators) to determine agreed capacity / demand future profile for distributed gas-fired generation connected to the Gas Distribution network.
- Operational/Real-Time - Establish information exchange mechanisms with ESOs to determine likely operational windows for distributed gas-fired generation connected to the Gas Distribution network such that gas network dynamic effects can be modelled.

Use of price signals

The advent of smart technology, coupled with greater variation in real time energy pricing, gives customers (both business and domestic) the opportunity to actively participate in energy markets to save money. For example, hybrid heat pumps could use price signals to determine which fuel to use, and hence be a major determinant of system demand. To facilitate the effective use of price signals in the gas sector as part of the whole system, the following functions are required under the following timeframes:

- Investment - Use multi-vector system modelling to determine the likely impact of price-based consumer behaviour (e.g. hybrid heat pumps or EV charging) on the dynamics of gas networks (PathFinder)
- Operational/Real-Time - Develop demand forecasting system which allows day ahead and within day modification of gas demand profiles based on cross-sector system pricing.

Emergence of new participants

The energy transformation is underpinned by a rapid growth in market entrants operating across all elements of the value chain - the gas system will need to develop processes to engage appropriately with all these actors. To develop these processes, the following function is required in the following timeframe:

- Investment - Develop a new process with DNOs requiring cross-sector assessment for any connection request above a certain capacity to ensure that the lowest cost option (either gas or electricity) is provided for customers.

Active management of networks, generation, storage and demand

The management of the Gas System has historically been largely passive but is becoming increasingly active within the DNOs. With a greater number of system actors looking to access the system (both exit and entry), more active management will be required to ensure that system constraints do not limit the commercial potential of new entrants. To ensure this, the following function is required in the following timeframe:

- Investment/Operational - Develop a real time mechanism for tracking system demand on a half hour basis (e.g. equivalent of publicly available Elexon data for electricity) and statistically representing areas of excess capacity suitable for connections.

Need for coordination across energy vectors

The coordination across energy vectors is an essential element of delivering value for customers in the energy transformation. To enable this coordination, the following functions need to be developed in the following timeframes:

- Investment - Develop a cross-vector demand forecasting tool which translates FES into regional scenarios and incorporates transport, flexible generation, heat network, domestic and I&C demand.
- Investment - Work with local authorities and devolved administrations to generate stakeholder led cross-vector energy plans that address wider requirements such as air quality and economic development

4.2 RIIO GD2 Implications of Whole Systems for the Gas Networks

It is increasingly evident that Gas Networks can no longer be developed and operated independently of other energy systems, or, if they are, that this is not in the best interest of the customer. This has various implications for GD2:

- Improved system scenario development is required, to be carried out on a regional basis with appropriate DNOs and other energy system actors.
- These scenarios need to be translated into demand profiles which are used as a common basis for investment planning across both gas and electricity networks.
- Integrated planning needs to continue as far as real-time operation, to allow gas network operators improved visibility of gas distribution network connected generation assets.
- Energy connection requests for large loads need to be considered by both local electricity and gas networks to ensure lowest cost solutions are identified.

To deliver the above, improved integration between gas and electricity networks is needed, and a range of innovation projects will need to be undertaken to develop the tools and processes required across the price control period. Finally, depending on the outcome of the innovation trials, a number of real investment projects will be required to embed the processes into business as usual (BAU).

4.3 Cross-Sector Network Coordination

In a world of increased whole system interaction, we believe it is imperative to step up our interactions with other actors in the forthcoming Price Control period.

Engagement with Local Authorities / Devolved Administrations

The localism movement is growing. Increasingly, energy policy is becoming a matter for regional authorities as it is directly linked to wider societal issues such as economic growth, air-quality and planning. While a level of policy is set by central Government and regulators who operate on a national basis, the energy voice is increasingly local. In addition to the established major corporate actors in the energy sector, there is a growth in community and Local Authority owned 'Energy Supply Companies' energy schemes, often developed on a not-for profit basis such as Robin Hood Power (Nottingham) and Aberdeen Heat and Power (Aberdeen City Council).

This is a rapidly evolving picture, as, while ambitions are growing, austerity in public finances continues to bite and there is a lack of statutory local powers over energy policy. Against this backdrop, SGN recognises the growing need to interact with stakeholders locally in developing and implementing investment plans. Recent research indicates that 82% of 434 Local Authorities have energy and carbon management plans and / or projects in place[14] (al W. e., 2017) and there is an increasing role for Local Enterprise Partnerships (LEPs) in setting the energy agenda and regional industrial strategies.

Areas for SGN interaction with local authority energy planning could include, but not necessarily be limited to:

- Provision of local energy demand data by sub-region.
- Engagement on strategies to support the air quality agenda.
- Energy incentive programmes.
- Local building specifications.
- Support on the development of district heat schemes.
- Support to renewable energy generation, either through community owned / developed renewable gas generation, or through the enablement of intermittent renewables through additional gas-fired generation.

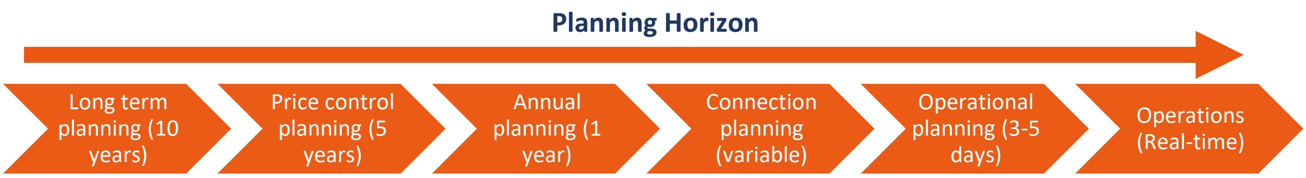
We propose to improve this interaction with Local Authorities in RIIO GD2 through the sharing of demand forecasts and support to local energy planning initiatives. We believe that this will yield improved customer outcomes through targeted investment.

Engagement with Electricity Networks/System Operators

The opportunities for improving customer outcomes through interaction between the Gas and Electricity networks will grow throughout the Price Control periods. SGN is geographically aligned with the following DNOs (Distribution Network Operators) – UK Power Networks, Scottish and Southern Electricity Networks and Scottish Power Energy Networks.

Interactions between the networks can be considered across a range of time horizons, as presented in **Figure 15**

Figure 16: Gas and Electricity Planning Interaction



[14] UKERC, 2017, local authority engagement in UK energy systems: highlights from early findings

Long Term Planning (10 Years)

Figure 17: SGN long term development statement

GDNs and DNOs are both required under Licence Conditions to annually publish a Long-term Development Statement. For the Gas Networks, this has historically taken a top down, statistically based approach to demand forecasting using macro-demand data from National Grid Transmission. In publishing the document, interactions are solely between the GDN and National Grid Transmission. For RIIO GD2 it is proposed that the process is amended to include an iteration of review with the relevant DNOs to ensure that Gas Network planning assumptions align with those of DNOs, particularly those associated with forecasted changes in peak demand across both systems.

Price Control Planning (5 Years)

Every 5-8 years, depending on the length of the Price Control, GDNs and DNOs submit comprehensive business plans justifying their investment and operational spend profiles. These business plans are largely based on demand forecasts, which in turn are based on scenario assessments. At present, while there is a comprehensive stakeholder engagement as part of this process, there is no formal interaction or sign-off between the GDNs and DNOs to agree a common set of scenario assumptions as a planning baseline. We propose that during RIIO GD2, SGN works with its geographically aligned DNOs to develop a joint scenario planning process to be used for RIIO GD3.

Annual Planning (1 Year)

Implementation of investment plans, as set out and agreed with the regulator through the business planning process, generally take place on an annual cycle of budgeting and investment sanctioning. This process translates long term planning into physical assets on the ground, and it is only at this point that cross-network interaction has material implications. We propose that during RIIO GD2 SGN works with its geographically aligned DNOs to share annual investment plans for those assets that have whole system implications – this will include, but not necessarily be limited to:

- Network reinforcements (both pipelines and AGIs) to support gas-fired generation assets, including BTM gas-fired CHP.
- Any other network connected assets that bridge the interface between gas and electricity, such as turbo-expanders at AGIs or power-to-gas projects.
- Large load connections, such as new Industrial and Commercial (I&C) loads or housing developments.

Connection Planning (Variable)

Many customers, particularly I&C have requirements for energy, rather than specifically gas or electricity. Energy vector interchangeability can be achieved through, for example, installing a CHP system on site to provide heat and electricity using a gas connection. At present, customers need to contact GDNs and DNOs separately to obtain connection quotations. We propose that we work with the geographically aligned DNOs to offer a service for customers whereby a minimum cost / impact energy connection is offered. A threshold of either demand level or system impact will be established as a baseline for the cross-network interaction. In many cases, spare capacity on the gas distribution network can be utilised at lower cost and in shorter timescales than a new electricity network connection.

Operational Planning (3-5 Days)

Both GDNs and DNOs have sophisticated operational planning processes which consider a range of factors to forecast short term system demand. For GDNs, this translates into a formal process of Offtake Profile Notices (OPNs) which inform National Grid Transmission of hour-by-hour demand profiles at all offtakes. At present, there is no mechanism for sharing demand forecasting between GDNs and DNOs. As such, the GDNs have no knowledge, beyond experience, of when distribution connected gas-fired generation is likely to be utilised, and hence the effect it is likely to have on in-day demand. Real time operation of the networks, particularly on tight demand days, can be optimised by visibility of operational planning data. We propose that we work with geographically aligned DNOs in RIIO GD2 to develop and implement an operational planning information sharing protocol.

Operations (Real Time)

Northern Gas Networks and Northern Power Grid are undertaking trials of more closely linked real-time operational information at the InTEGRal development site. We believe that there is value in expanding this activity to share real time information across control rooms, particularly to allow within day demand adjustments for gas based on switching distribution connected gas-fired generation on or off. We propose that our interaction with DNOs on operational planning is expanded to include real-time operations information sharing between control rooms.

Summary

We have tested these assumptions and approach through workshops with the DNOs and several Local Authorities in the lead-up to our Business Plan Submission.

5 Future Energy Scenarios

5.1 Scenario Planning

A key aspect of developing a whole system strategy between multiple stakeholders is ensuring every stakeholder is working towards a consistent target. The end goal of the whole energy system is an integrated network which delivers to customers energy which is clean, secure and affordable.

There are multiple ways in which the whole energy system landscape may develop in the future to achieve this common goal. This direction of travel is dependent of multiple factors, from policy decisions (especially the decarbonisation of heat) and technological advancements, to public opinions and international progress in achieving global climate change targets. The end target is clear for our whole system, but the route to achieve it is a topic of debate in the wider industry. The way the various markets that form the whole system develop in the coming years cannot be assumed in planning. There must be some level of assumption to assist in planning, but we believe the optimal metric to determine how and where the whole system is moving is through a set of market indicators.

National Grid's Future Energy Scenarios (FES)

National Grid's four Future Energy Scenarios (FES) describe four possible futures for the whole system of the UK electricity and gas grids; in effect how our energy is generated and how it is used. Since 2011 the FES document describes the scenarios used in their annual planning processes. The scenarios considered have evolved and in the 2018 edition four scenarios are presented, Community Renewables, Two Degrees, Steady Progression and Consumer Evolution, this is shown in Figure 17[15]. To summarise the scenarios:

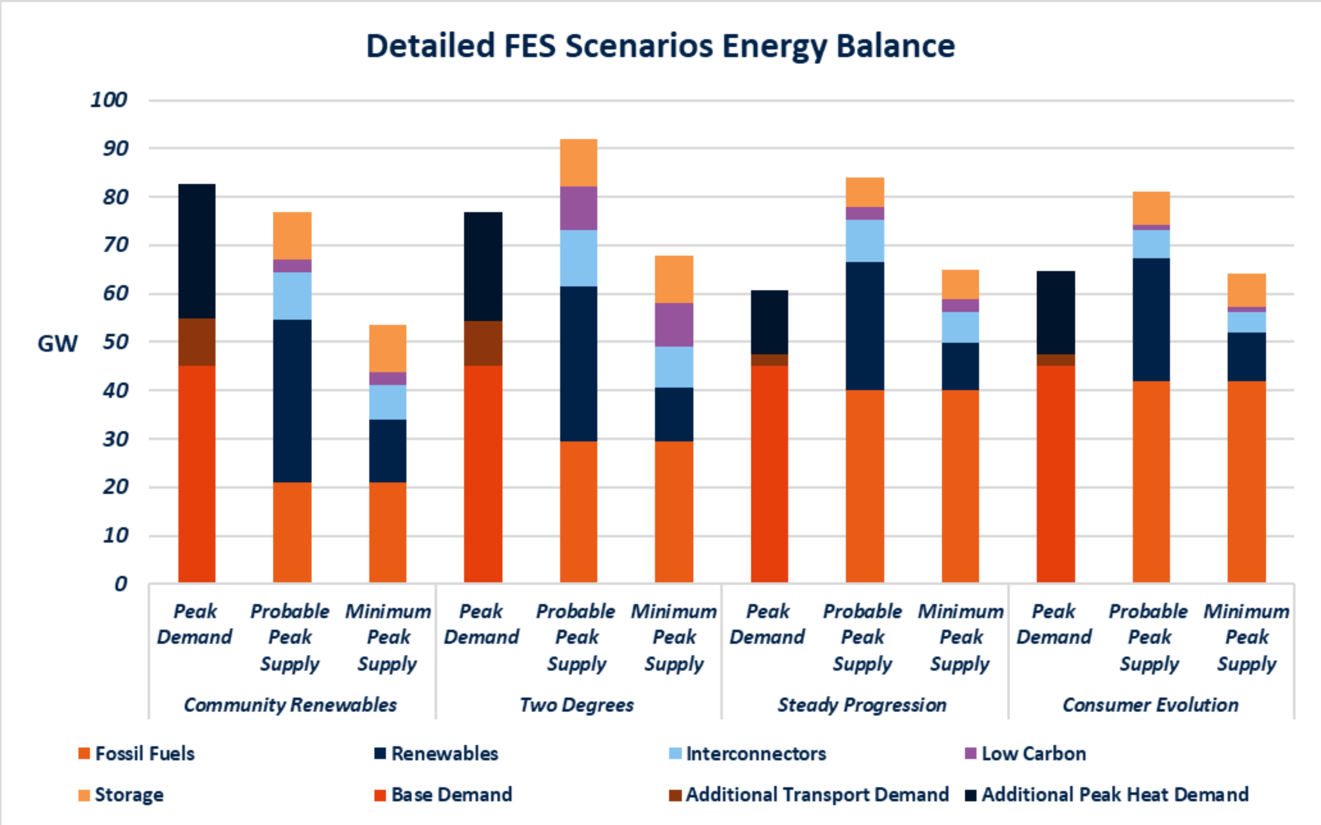
Figure 18: FES Scenarios Summary

- Community Renewables achieves 2050 decarbonisation targets through a decentrailised energy landscape
- Two Degrees acheives 2050 decarbonisation targets through a more centralied energy landscape.
- Consumer Evolution comes close to, but does not achieve 2050 decarbonsaition targets through decentralised energy landscape.
- Two degress comes close to, but does not achieve, 2050 decarbonsation targets through a more centralised energy landscape.

Each scenario is based on assumptions behind gas and electrcity supply and demand, as well as government policies and customer behaviour.

[15] National Grid – Future Energy Scenario 2018 - http://fes.nationalgrid.com/media/1363/fes-interactive-version-final.pdf

Figure 19: FES 2018 Analysis



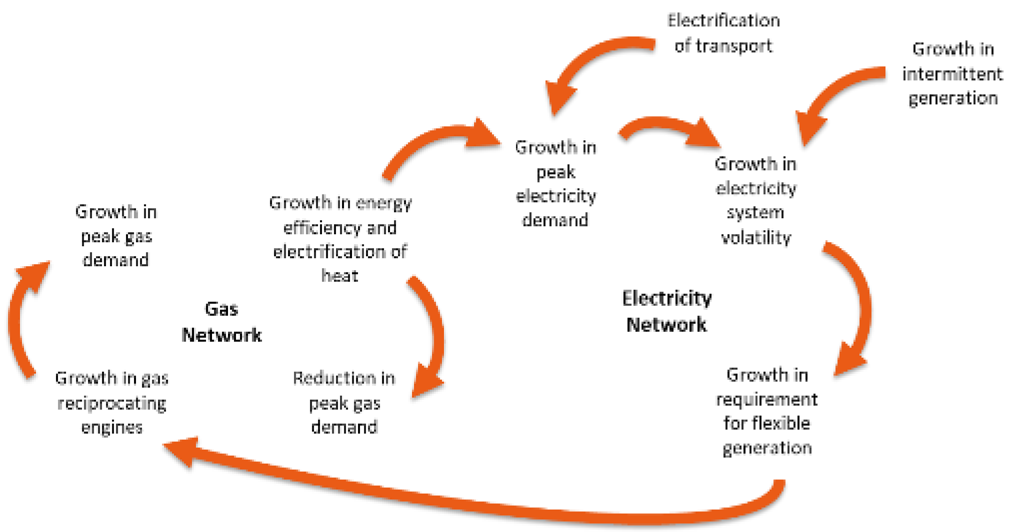
We carried out a high level analysis on the scenarios presented here, focussing on electricity supply and demand at peak. Many of the scenarios assume widescale electrification of heat and transport, and do not consider hydrogen in much significance. We considered the quoted electricity generation capacity in 2030 and derived a probable peak supply electricity supply using load factors and a minimum possible supply, using minimum load factors (i.e. very low wind, no solar, poor interconnector availability from the continent). These supplies were compared to an estimate of peak demand based off current peak demand trends, with additional transport and heat demand derievd from charging electric vehicles at peak and uptake of air source heat pumps. The above figure shows the outcome of this.

FES 2018 was carried out considering a decarbonisation target of 80% by 2050. Recent legislation has moved this target to net zero by 2050 for the UK government and 2045 for the Scottish government. In the two scenarios which do not achieve decarbonsiation targets – consumer evolution and steady progression, the mimumum peak supply is greater than the maximum forseeable demand, the grid is balanced and security of supply is achieved. In the two scenarios which do – community renewables and two degrees, the maximum foreseeable demand is significantly greater than the minimum supply. This presents a security of supply issue. Not one of the scenarios, under this analysis, complies with the energy trilemma of a sustainable, reliable and affordable energy supply.

We believe this gap between supply and demand which may occur in a worst case scenario (the probability of which has not been determined) is derived from a combination of lack of reliable genertaion (renewable generation i.e. wind and solar, is highly intermittent and dependent on natural conditions), overly optimistic heat pump assumptions regarding performance and the suitability of the housing stock for retrofitting, ambitious assumptions surrounding the availability of interconnector capacity, ambitious assumptions surrounding time of use tarrifs and grid balancing mechanisms and a lack of energy storage mechanisms to name a few. This supply gap is unlikely to occur as it represents a 1:20 scenario with very low generation capacity availbale, but if it does the whole system must be able to maintain security of supply. We believe that by working under assumption based scenarios, the whole system will require signifcant capacity for peaking, which is likley to be provided by gas peaking plants. Due to this approach, the way the whole system predicts demand is fixed and cannot be proactive to changes in the market. There is a danger that the continued electrification of parts of the whole system's energy demand may outstrip the capaibiliy of the whole system to contract capacity to supply this ever-increasing demand.

This analysis is high level, but nonetheless highlights the potential shortfalls of working with assumption derived scenarios to provide an answer to the highly fluid, and complex problem that is the decarbonisation of the whole energy system.

Figure 20: Circularity of Energy System Vector Shifting



Market Indicators

Our analysis of the scenarios indicates that there are gaps in the data and assumptions being used to derive the Future Energy Scenarios. Whilst we appreciate some assumptions are required, we believe that market indicators would be a more effective way of determining the true position for each assumption. Each assumption is dependent on one another, and also dependent on a multitude of external factors.

Key performance indicators (KPI's), which comprise leading and lagging indicators allow factors which impact on each assumption to be considered. Leading indicators are input oriented, which are difficult to measure but easy to influence. Lagging indicators are output oriented, which are difficult to influence but easy to measure.

For example, when considering the assumed capacity of offshore wind generation on the grid, we believe analysing KPI's would yield a more realistic estimate than a straight-up assumption as is seen in FES. Leading indicators for offshore wind capacity include government subsidies available, cost of production, availability of space for installations and advancements in technology. Lagging indicators include the number of turbines installed, the capacity factor of the installed turbines and the location of installations.

It is critical when developing a whole systems approach that each industry within the whole system is in agreement as to how to progress each part of the whole system towards the common goal of a fully decarbonised energy system compliant with the trilemma. Using straight assumptions to determine what the future looks like can harbour differences in opinion between competing parts of the whole system (i.e. the debate surrounding the decarbonisation of heat between the gas and electricity sectors) as to what the optimal solution is to a problem, this can result in confused and conflicting messaging and therefore modelling. Using market indicators to derive assumptions allows better estimates of the future to be made, eliminates bias which is indicative of competition, and more importantly outputs assumptions which change as various markets change.

5.2 Analysing and Modelling Decarbonisation Solutions for the Whole System

Every region and component of the whole energy system is required to transition its energy demand to be supplied by net-zero energy. There are many technologies and energy vectors competing to provide solutions to whole system decarbonisation challenges, such as the decarbonisation of heat and transport. It is unclear in the current market what the optimal solutions are, and it is clear modelling comparisons are required to determine this.

Modelling can be undertaken at a micro, city, regional and national scale to compare technologies and solutions to different challenges. Analysis of future energy scenarios is often undertaken at a national level, an example of this is National Grid's annual FES report. National analysis is useful for debating energy policy and assessing the bigger picture, but it does not necessarily scale down to regions and cities to provide practical solutions, where energy demand and supply can be highly varied.

Analysing the whole system at a regional level is useful in some cases. Pathfinder modelling carried out to assess different decarbonisation solutions in Edinburgh and Brighton demonstrated decarbonisation was possible through a number of solutions and also highlighted the different requirements of different regions in terms of their energy demand and current energy landscape. This modelling considered the energy supply to Edinburgh and Brighton in terms of what was available regionally.

Assessing and comparing different technologies and approaches at a regional level is most useful when each technology and approach is available. Providing regional solutions based on what is available locally and combining these solutions together to form an overarching national solution is unlikely to provide an optimal answer to the decarbonisation of the whole system.

Regional and City modelling is useful when the region is self-sufficient in its energy generation and supply. Allowing modelling to be carried out with every option available to determine the best solution i.e. areas with an abundance of wind energy and/or biomethane. When there is full availability of supply, the most cost-effective solutions which disrupt customers the least can be sought.

For example, a city such as Aberdeen, with an abundance of renewable energy locally available, gas infrastructure and potential carbon capture in place to produce large quantities of hydrogen as well as biomethane and/or bioSNG has full availability of clean energy in a variety of vectors. The option therefore exists to install heat pumps or hydrogen boilers, or hybrids. Similarly, there exists the opportunity to develop hydrogen refuelling stations and EV charging points or both. The most cost-effective solutions can be modelled and determined for each sector of the whole system within the city without limitations.

Conversely in a city or region where energy supplies are not in abundance, the options for decarbonisation of its sectors become restricted. If a city's energy supply is mainly through imports, modelling locally will not yield an appropriate solution. If for example, it is not possible for a region to produce sufficient hydrogen or biomethane, it may be forced to install heat pump technology in its housing stock, which may not be suitable and doing so would cause significant disruption to customers through retrofitting. This limitation would also require significant grid reinforcement and investment in power generation. This solution is unlikely to be the most affordable and would likely cause the most disruption to customers. This is likely to be the case in some of Britain's largest cities if it is left to regions to determine a decarbonisation solution.

This represents the value of whole system thinking. Transporting low-carbon energy via hydrogen allows regions with excess supplies to feasibly supply demand in places far beyond the reach of traditional power transmission. By enabling the national gas transmission system to deliver renewable energy at the same scale as it does with natural gas, regional limitations are removed. National solutions are required to feed into regional analysis.

Modelling regional decarbonisation solutions with an assumed input of decarbonised gas at a national level, allows full flexibility of decarbonisation solutions to be achieved and all options to be explored. The importance of minimising disruption to customers to policy makers cannot be understated. We firmly believe that utilising energy delivered through hydrogen in hydrogen boilers provides the least disruptive solution to the decarbonisation of the nation's heat requirements. Facilitating the delivery of hydrogen through new or existing national transmission systems, in a similar way as natural gas does now, would allow every customer of natural gas to switch to hydrogen and biomethane relatively stress-free, and at a far lower cost than installing heat pump or hybrid heat pump technology. This capability provides maximum value to customer and allows policy makers full use of the UK's extensive gas infrastructure when modelling for the most cost effective, least disruptive and most practical approach for decarbonisation of each region and part of the whole energy system.

5.3 Pathfinder Modelling

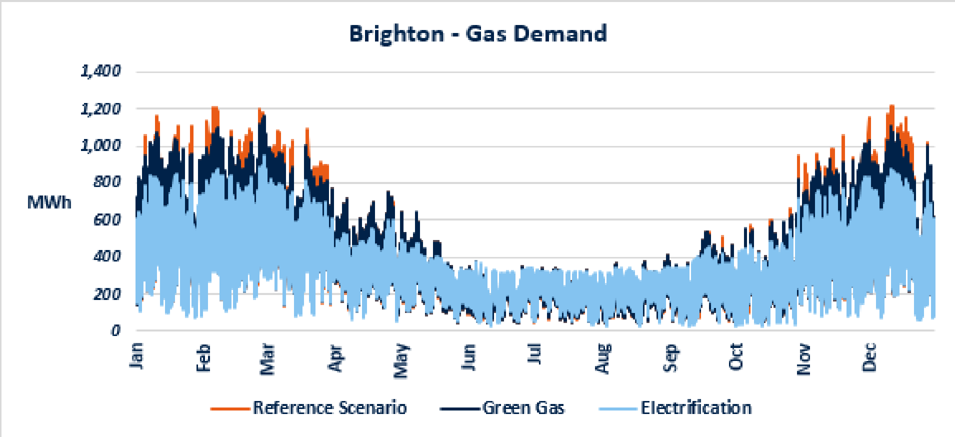
To illustrate the potential impacts of different decarbonisation pathways at a more localised level, and to better understand the potential implications for gas and electricity network system planning, we, along with Progressive Energy, have conducted system modelling of two cities; Edinburgh and Brighton. System modelling has been undertaken using the Pathfinder model, created by WWU and Delta-EE. The model is a highly sophisticated engineering tool which allows the hourly balance of supply and demand across the gas and electricity network to be viewed over the course of a year.

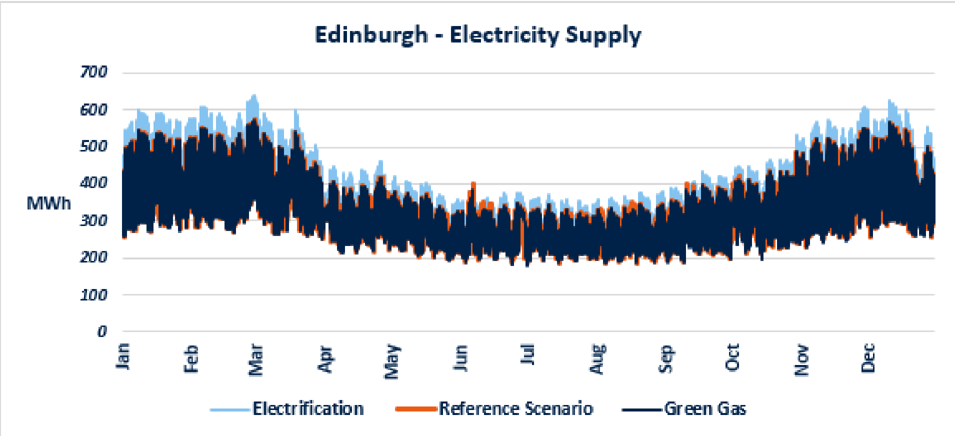
The objective of the modelling activity was to view investment strategies from a wider, more holistic perspective, by understanding the implications of any given strategy on both the gas and electricity systems and focussing on the interface between the two. The analysis consisted of mapping the current energy needs (heating, power and transport) of two SGN reference locations, Edinburgh and Brighton. These locations were chosen as they represent reasonable sized cities in Scotland and the South-East of England. While there are some common features across the two regions, there are enough differences in baseline conditions to yield some interesting differences in the modelling conclusions.

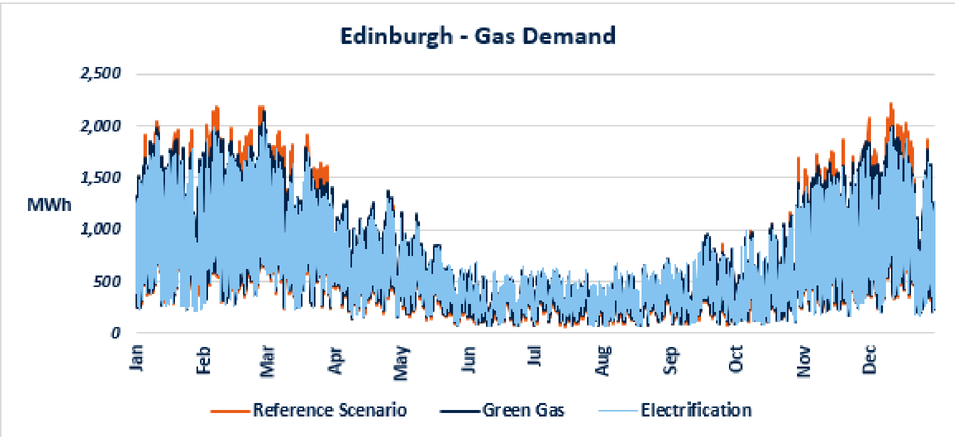
The modelling was carried out considering a reference point of National Grid's FES 2018 'Steady Progression', which we believe to be the most reflective of how the current whole system may develop in a BAU scenario. Minor refinements were made to the dataset to derive the 2030 reference point. This UK reference point, as calculated by Pathfinder, was accurate and in agreement with the National Grid forecast.

The carbon target which dictates the level of penetration of decarbonisation approaches was derived from the former target of 80% by 2050, and not net-zero. Pathfinder cannot consider in its calculation emissions from sources such as agriculture and waste management. As such, the modelling only targets an 80% reduction in emissions (compared to 1990 levels) in electricity generation, commercial heat and power, road transport and domestic heating. The specific targets for Edinburgh and Brighton were not assumed to be the same as the UK average, and adjusted accordingly (both were lower due to less than average local energy intensive industry).

A number of 2030 scenarios were modelled, the results of which are summarised in the Graphs and descriptions below:







Reference Scenario

The reference scenario is based on FES 'Steady Progression', where there is a slower drive to decarbonise, therefore appliance efficiency improvements are meagre and there is little electrification of heat by 2050. There are however, significantly more EV's on the roads, with some natural gas-powered vehicles. Smart technology is important for managing peaks. Natural gas boilers continue to dominate space heating, with limited heat pump rollout and little improvement in home efficiencies. In terms of electricity generation, there is much greater emphasis on large scale generation, with high levels of offshore wind capacity and nuclear capacity. Gas plays an important role in providing flexibility and gas fired generation fitted with CCUS develops through the 2040's.

By 2030, the modelled reference scenario sees a significant increase in installed wind and interconnector capacity, with smaller increases in solar and hydroelectric capacity. Long terms nuclear growth is projected in steady progression by 2050, but 2030 coincides with a low point due to decommissioning of existing assets ahead of the commissioning of new assets. By 2030, there are few demand changes, other than the rollout of EV's. The reference scenario is not compliant with decarbonisation targets in its trajectory.

In the reference scenario, electricity supplied increases and gas supplied decreases. The decrease in gas is due to improvements in home efficiencies and a reduction in gas fired electricity generation. The increase in electricity consumption is mainly due to substantial growth in EV use. In this scenario, electricity supply does meet electricity demand at peak. This is due to the coincidence of peak with high wind availability. In both Edinburgh and Brighton, peak gas demand drops by over 10%. Peak electricity demand increases slightly in both cases. At peak, just under 60% of electricity is derived from wind.

Constrained Peak Demand Scenario

The reference scenario assumes full availability of all generation types up to their rated capacities for non-intermittent types and applies an hour-by-hour load factor to intermittent sources (wind and solar) based on historical data. In reality, generation availability is constrained for a range of reasons which are not reflected in the baseline model. To explore the sensitivity of the 2030 reference scenario to constrained electricity supply, a series of technology specific constraints were applied. The methodology utilised for developing these constraints broadly reflects that of National Grid's Winter Outlook[16] for nuclear and interconnector supply, with Pathfinder actual data utilised to identify the low point of wind supply.

- It is assumed in this scenario that only Hinkley Point C and Sizewell B will be operational by 2030, with a combined capacity of 4.4 GW. A derating of 92% is assumed at peak, this gives a contribution of 4.1 GW to peak generation.
- In terms of interconnectors, it is expected there will be 14 GW of capacity. We believe that it is unlikely that this capacity will be fully translated to supply at peak. This is due to low wind output on the continent coinciding with low output in the UK. 7.4 GW are available from interconnectors in this scenario.
- Wind generation has been time-shifted to align the peak demand with an annual system minimum supply from wind, for this scenario, the load factor of wind generation is assumed to be 3.4%. It should be noted that no statistical correlation work has been carried out to assess the likelihood of this scenario, as it is influenced by a multitude of factors. However, the approach taken does set a worse case scenario for consideration.

Applying these constraints to generation mix yields a shortfall in supply of 7% in Edinburgh and a very slight shortfall in Brighton. In reality however, National Grid is required to operate the network with a level of reserve, and so a scenario where supply just met demand wouldn't be tolerable from a systems operation perspective. In this scenario therefore, it is highly likely additional capacity would be required, which is likely to take the form of gas peaking or CCGT generation.

Home Efficiency Sensitivity Study

In the reference scenario, the main driver for a decrease in gas demand is improvements in home efficiencies. It is assumed that a blanket improvement of 19% is achieved in home efficiencies. This target is ambitious and not currently policy driven. In this sensitivity study, trajectories of 2% and 12% were also modelled to assess the impact of this target not materialising.

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[16] National Grid, Winter Outlook, 2018/2019, October 2018

At a 2% trajectory in Brighton, peak and annual gas demand increases as population growth outstrips any energy demand reductions due to efficiency. At a 12% trajectory in Brighton, the result is reversed. So, unless a home efficiency improvement trajectory of greater than 7-8% is achieved, gas demand is likely to remain flat. In Edinburgh, there is a growth in annual demand and a minor reduction in peak demand on the 2% trajectory.

Peak gas demand has reduced in recent years on a seasonally adjusted basis. It is difficult however to predict the forwards trajectory for continued reductions. This modelling has been carried out to demonstrate the sensitivity of the model outputs to assumptions to energy efficiency.

Electrification Scenario

The reference scenario does not achieve 2030 emissions targets for Edinburgh or Brighton. A scenario has therefore been developed to increase demand side electrification to achieve this target by increasing the number of EVs and heat pumps. From this, the required increase in installed electricity generation capacity to meet this demand has been calculated.

To achieve decarbonisation targets, ASHPs and EV penetration were aligned with National Grid's Community Renewables scenario (3.5 EVs for every heat pump). In Brighton, this resulted in all cars being replaced with EVs and the target still not being achieved, so the number of ASHPs was further increased until compliance was achieved.

Edinburgh and Brighton present quite different outcomes in this scenario, driven primarily by Brighton having a much greater proportion of properties connected to the gas network than Edinburgh. Brighton requires significantly greater changes (all cars must be electric by 2030 in Brighton, where only 40% must be electric in Edinburgh). In turn, this would require a significantly higher growth in electricity supply in Brighton than Edinburgh, requiring more investment in generation capacity, transmission and distribution infrastructure and ancillary services such as frequency control.

While gas demand at peak does drop due to the replacement of approximately 40% of gas boilers with ASHP's, it only drops by around 25% from the 2018 scenario as a considerable proportion of peak electricity demand is still met by gas fired generation.

To achieve this scenario, significant changes would need to be made to both regions. It is clearly a substantial challenge to achieve this level of change by 2030, with many barriers. These include but are not limited to:

- The significant rollout of EV charging points (either in each home or rollout of significant shared infrastructure) and heat pump retrofits would be required, which would bring about considerable cost to the consumer and changes in behaviour to shave peaks and share chargers.
- This investment in the electricity network infrastructure could not be offset with a corresponding reduction in gas network investment, as even despite the rollout of electrification, more energy would still be required to be transported by gas than electricity. As such, routine investment would continue to be required.
- To achieve the required trajectory of change, substantial asset changeover would be required before existing assets had reached the end of their economic life, adding an extra economic penalty to the transition.
- To achieve the required number of ASHP installations, many would need to be installed in properties which are either too small for the heat pump to be efficient or properties which being insufficiently insulated. Modelled improvements in the carbon intensity of heating are unlikely to be met with the existing housing stock in Edinburgh and Brighton. ASHPs operate most effectively in new-build, well-insulated, medium sized houses which are unlikely to be built at the scale required for optimal heat pump performance in the 2030 timeframe.
- In terms of consumer choice. Without significant financial incentives, and, potentially legal requirements for change, it is unlikely that the required rate of consumer behavioural change can be achieved, particularly if it requires the deployment of personal capital.

We conclude that achieving compliance with emissions reductions targets in Brighton and Edinburgh by pursuing a solely electrification-based approach is highly challenging from a deliverability perspective will lead to economic inefficiencies resulting from early replacement of existing assets and will result in considerable societal impact owing to the level of disruption arising from the required electricity network upgrades.

Green Gas Scenario

In order to assess the feasibility of achieving 2030 emissions reductions by the increasing use of green gas, a scenario combining increasing levels of biomethane, alongside hydrogen blending in the distribution network was developed.

Both Edinburgh and Brighton were assumed to receive their proportional amount of biomethane based on each region's proportion of national natural gas usage and a national capacity of 100 TWh per year[17]. In addition, a 20% blend of hydrogen was assumed for domestic and commercial customers based on the HyDeploy project, and a 50% blend for industrials (noting that, this will actually be a proportion of industrials switching to a 100% or high blend, and others remaining at the network level of 20% blend). A 100% conversion of the domestic network to hydrogen in the 2030 timeframe was not deemed credible in either region and was therefore not assessed.

By rolling out this level of green gas in the network, compliance can be achieved in Edinburgh, but this level is approximately 5% away from compliance in Brighton. The next step to deliver compliance would be to progressively switch flexible generation in the model to a low carbon fuel such as hydrogen, although this has not been modelled.

While compliance can be achieved it is by no means straightforward while following a green gas trajectory. Particular areas of concern include but are not limited to:

- Biomethane feedstock availability – The level of biomethane capacity, while technically feasible from a feedstock availability perspective, would require an approx. 30-fold increase in the level of biomethane currently being produced, and would require almost all of the useable feedstock available in the UK (both waste and non-waste streams) to be deployed into creating grid quality natural gas (or, alternatively, hydrogen though a gasification process).
- Regulatory approval for hydrogen blending – Hydrogen blending at 20%, while being rapidly progressed through the HyDeploy project, is not yet approved by the regulator (the HSE) for rollout in the public network. Furthermore, while there are credible hydrogen / CCUS projects under development in Scotland which could feasibly supply Edinburgh by 2030, it is harder to conceive a similar project being able to supply Brighton in similar timeframes.

However, offsetting these concerns, there are considerable benefits to deploying a green gas strategy to deliver emissions reductions. Firstly, unlike the electrification scenario, the transmission and distribution infrastructure is already largely in place, this will minimise network reinforcement requirements giving economic benefits and improving societal acceptance of change. Furthermore, this scenario would minimise the impact on customers – the green gas scenario (unlike the electrification scenario), requires neither changes to domestic appliances nor personal investment from customers (up to 20% blend). This significantly improves political acceptability versus a solution which requires widespread consumer investment.

[17] Cadent Gas Ltd. Review of Bioenergy Potential: Technical Report, June 2017

Electrification and Green Gas Scenario Equivalency Assessment

The equivalence between the green gas and electrification pathways was considered to qualitatively illustrate the scale of change required to achieve the 2030 targets for Edinburgh and Brighton.

Taking the same approach of setting a 2030 baseline based on a FES Steady Progression scenario, the model was then driven to emissions compliance by increasing the number of ASHPs (over 50,000 would be required in Edinburgh by 2030, up from just over 500 in 2018). Achieving the same result from biomethane would require approximately 7 biomethane plants to be constructed, each of 10 MW capacity.

While a full cost comparison between these two pathways (due to limitations in the Pathfinder model) has not been completed, the RHI support requirement for the green gas pathway would be considerably lower than that for the heat pump scenario. Perhaps more importantly, the level of societal engagement required to install 7 biomethane plants is considerably lower than that required to install over 50,000 ASHPs. A principle developed during this modelling and undertaken previously with WWU is that solutions that rely on fewer stakeholders to take action to achieve a given decarbonisation result should be favoured above those that rely on more stakeholders to achieve the same decarbonisation outcome.

Qualitatively, the green gas scenario appears to be considerably more practicable to deliver due to the far lower level of consumer and network investments required. In reality, a combination of both approaches will be required to deliver the optimal whole system solution, but the ongoing need for a comprehensive and reliable gas network to meet peak energy demand is clearly demonstrated.

5.4 The Role of the Network in an Electrified World

If the whole system is to comply with net-zero decarbonisation targets, it cannot continue to rely on energy derived from unabated natural gas. Policy decisions surrounding the decarbonisation of heat must and will be made and mandated in the early-2020's. This trigger point will likely determine the future role of the gas industry.

As a gas network, we fully appreciate that the future of the industry should not be one where we deliver energy to customers from fossil fuels. We believe that decarbonising heat through green gas (hydrogen and biomethane), is the optimal route in terms of required investment, disruption to customers and value to customers and stakeholders. At the same time however, should our pathway to decarbonisation result in the disqualification of hydrogen gas as an energy vector due to safety, practicality or cost, an electrification pathway may be pursued.

In this scenario to meet the outlined challenges, the gas network may play a reduced yet critical role in minimising the power emissions, albeit not net zero. It may also provide a critical lifeline for UK industry. However, if the challenge of electrification are overcome, the network may be used for:

- The gas network may be utilised, as it is currently for the storage of significant quantities of energy through line pack. It could be used for the mass storage of biomethane, or natural gas for use in power generation coupled with carbon capture technology (in the case of biomethane, this would result in negative emissions).
- It could be used for the storage of hydrogen as an energy storage mechanism for use in fuel cells or power stations.
- The network could be used for the storage of carbon dioxide from power generation. Or even the storage of carbon in alternative compounds.
- The network could be used for the storage of synthetic natural gas from methanation of hydrogen and carbon dioxide,
- The network could be used for the transport of ammonia or liquid organic hydrogen compounds for backup power generation

6 Stakeholder Engagement and Customer Value Proposition

6.1 Stakeholder Engagement

Stakeholders want us to look beyond the network value chain in terms of investment planning. There is a clear need beyond the normal delivery of the regulated workload to be responsive to the emerging needs of both customer and stakeholders, this encompasses the ethos of a whole system that we are developing in line with our whole systems charter. This charter sets out the commitments we are making to work closely together in the RIIO-2 price control to optimise customer outcomes.

To test this approach, we have undertaken a wide range of engagement activities to better inform our development of a whole system. This has ranged from one to one discussion with the individual electricity network operators in our footprint, where we provided an overview of our whole system approach and charter. This was well received, the DNOs now have the opportunity to jointly develop this document and we will encompass their feedback in the final version.

We have also presented our whole systems approach at the Future of Heat panel seminars we held in 2018. This stimulated a good discussion between the participants, with the advice from stakeholders that we should be addressing a whole system challenge with cross-sector (transport, electricity) and cross-vector (biomethane and hydrogen, etc.) collaboration. We have welcomed this feedback and making this one of our key objectives in GD2, developing projects, such East Neuk, to ensure a whole energy system is evidenced, co-ordinating to maximise decarbonised energy across systems.

Further engagement and liaison has taken place with the electricity network operators through the Open Networks project, co-ordinated by the Energy Networks Association. Open Networks brings together the nine British and Irish electricity grid operators, the British Government, the energy regulator Ofgem, respected academics, and NGOs.

This has been primarily through Work Stream 4 of the open networks project, which has been tasked with looking at Whole Energy Systems, in the context of the gas and electricity networks. The group is in the process of developing a number of products to improve both data-sharing in relation to mid to long term network planning and in a more coordinated approach to the operation of both networks, specifically around gas generation plant. These products complement our whole system charter and will be presented to the Open Networks steering group.

Scenario Planning – Developing a Common View

Along with other GDNs. we are engaging with the FES team at National Grid to work together on how the scenarios can better reflect some of the key drivers for our network and as a whole system. We have also worked with the other energy network operators as part of the work set by the Customer Challenge Group (CCG) in November 2018, using FES as the framework.

The CCG asked the networks to develop a core scenario that enabled a whole system impact on the business plans to be assessed. The focus of this work was on key drivers that could act as a trigger for investment on the networks and may have a material impact in business plans.

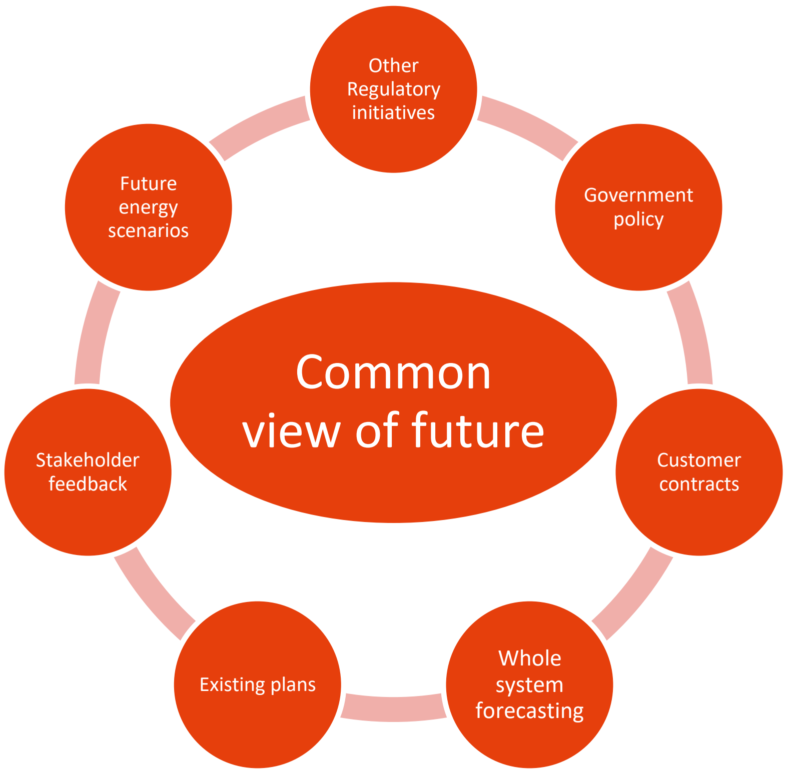
The FES are formed from a list of 70 assumptions, these were reduced down to 46 building blocks which licensees recognised as being relevant key drivers having a direct impact on the gas and electricity network. Factors such as small scale generation and hydrogen were also included, although they do not form part of the 2018 FES, they were felt to be materially important. Hydrogen has subsequently featured more in the 2019 FES publication.

Against each of the key drivers a level of uncertainty, interdependency, cost materiality and range of values in 2030 was developed. The pathway to 2030 will vary by key driver, as in some instances the change will be a decrease from today, such as nuclear generation, whilst others will increase such as hydrogen and electric vehicles.

The common view (Figure 20) has been developed as a reference point for networks, recognising that this will not reflect the local ambitions or regional drivers in the development of the business plans. It is therefore crucial that for the areas of greatest uncertainty, heat, transport, generation, etc. are mitigated by the whole sytem funding mechanisms that we are proposing to introduce, allowing flexibility, rather than relying on forecasting accuracy. For instance, we are indicating a low level of capex expenditure at present but should government policy change towards a hydrogen solution for heat this will drive the need for the reopener mechanism.

6.2 Customer Value Proposition of Whole Systems

Figure 21: Common View Development Flowchart



It is no longer in the interests of customers for the gas and electricity networks to exist in such separation. System boundaries are beginning to be broken down. Clean energy must be delivered to customers in a way which is safe and affordable. The gas industry nor the electricity can deliver all of this energy in the most compliant way to the energy trilemma. The whole energy system is highly complex and each part of it will require a bespoke solution. Without a whole system approach, this optimal approach cannot be achieved.

The development of a whole system approach is the only way to ensure the efforts of the energy industry are fully focussed on delivering the cleanest, most affordable and most reliable energy to customers. If not, customers will pay more, maximum value of the proposed funding in RIIO-GD2 will not be achieved, and the overall goals of the gas industry, (and the wider energy industry) will be jeopardised. The value to customers of a whole systems approach is intangible, but our proposal in GD2 to develop this strategy will seek to define this value and how to deliver it.

7 Assurance

Our Business Plan, including Appendices, has been subject to a rigorous assurance process which is detailed in Chapter 3 of the Plan and the Board Assurance Statement.

Our Chief Executive Officer was appointed as the Sponsor for the Whole Systems and Scenarios Appendix which has been through the following levels of review and assurance:

First Line

This was undertaken at project level by the team producing the document, as a regular self-check or peer review.

Second Line

This was undertaken independently within the organisation to review and feedback on product development, including a workshop on whole systems. Both Senior Manager and Director sign-off was obtained.

Our RIIO-GD2 Executive Committee: (1) considered the appropriateness of assurance activity for the Appendix and (2) provided assurance to SGN's Board that the Business Plan meets Ofgem's assurance requirements.

Third Line

This was undertaken by external advisors and groups providing critical challenge during the development of products within the Business Plan. In addition to the feedback and challenge provided by the Customer Engagement Group (CEG) and Customer Challenge Group (CCG) this Appendix was developed after consultation with and advice from:

Advisor / Group	Contribution
Stakeholders	Specialist Heat Panel stakeholder sessions and Shared Future stakeholder event.
Progressive Energy	Pathfinder modelling and review of whole systems section.
DNVGL	Calculations checks and final review of Appendix.

Fourth Line

No fourth line assurance was conducted on this Appendix because the third line assurance obtained during development was considered appropriate external review in this new area of the Business Plan.