The Voice of the Networks

Energy Networks Association

Common RIIO2 Scenario

March 2019

1. Executive Summary

In 2018 Ofgem and the RIIO-2 Challenge Group (CG) requested networks across transmission, distribution, gas, and electricity to agree a set of common factors and assumptions for developing their core view of the future for RIIO-2. Network companies have risen to this challenge. Working collaboratively over a six-month period, the licensees have identified, discussed and debated the key areas that could have a material impact on RIIO-2 business plan submissions. The ENA's Cross Sector Common View working group has provided regular updates to the CG and has provided this final report by the requested deadline of the end of March 2019.

The report highlights the key drivers that network companies consider most materially impact the plans in RIIO-2 and subsequent price control time frames, together with supporting evidence and interdependencies. It also provides numerical ranges behind our uptake assumptions and identifies where there are differing views.

Networks have come together in an unprecedented manner, not seen before at previous price controls. Customers will benefit from this increased collaboration and greater sharing of knowledge and detailed insight. Ofgem should be in a stronger position to understand the background to company forecasts and have a consistent reference point to gauge individual company plans against. Companies have gained through this process and by working together the scope for well-justified plans has increased and a common reference point has been generated, against which companies will be able to explain why their individual plans, built from local knowledge and detailed interaction with their stakeholders, differ from this industry view.

We are in a period of significant change and this work reflects our best understanding based on the information available to us today, and will be refreshed and updated in due course. Given the impending business plan timescales in 2019, the working group has agreed that the earliest revision should take place in 2020. Ahead of the RIIO-ED2 business plan submissions, licensees across all sectors will work together to ensure that the relevant factors and latest available information is utilised.

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2. How this work can be used

2.1. Original ask from Ofgem and the Customer Challenge Group

In 2018 Ofgem and the RIIO-2 Challenge Group (CG) requested networks across transmission, distribution, gas, and electricity to agree a set of common factors and assumptions in developing their core view of the future for RIIO-2. It was recognised that the major building blocks may include factors such as:

- Overall demand (by energy source)
- Some disaggregation of drivers of demand (such as EVs)
- Connections (including volume of green gas connections)
- Quantity and form of generation
- Forecasts of significant economic indicators.

The licensees were requested to develop a core scenario that enabled whole system impacts of the business plans to be assessed[1]. The focus of this work is on the key drivers that would trigger investments in the networks that will have a material impact on licensees' business plans.

There are several key drivers that have a high uncertainty of their growth, the uptake of EVs for example, but could have a significant impact on the investment required on the networks. Equally there are some technologies, such as the uptake of heat pumps that could cause cross vector implications.

2.2. Scope of this work

This work focuses on specific key drivers which have been identified as material by the licensees, at this point in time. They have been assessed individually and therefore the common scenario cannot be viewed as a homogeneous scenario. Each key driver should be viewed as an individually derived, estimated change of that driver, informed by the majority view of the licensees.

The other key limitation is the timescale. This work only considers up to 2030, as the uncertainty beyond this point is currently too significant for the current phase of this work to be valid over a longer time horizon. Where possible, a commentary has been provided on the longer-term uncertainty. The first RIIO2 price control periods for ET, GD, and GT are scheduled to run from 2021 until 2026, with ED running from 2023 until 2028. In considering up to 2030 licensees have ensured that these periods are fully covered, and the current intention is that this work will be refreshed before the business plans for the ED price control period are submitted.

This work is focussed on the material external factors which impact network operator's business plans and does not consider asset management activities such as the replacement of assets.

[1] https://www.ofgem.gov.uk/system/files/docs/2018/09/riio-2_business_plans_-_initial_guidance.pdf

Post 2030

Overview

Projections of gas network usage post 2050 are highly dependent on the success and type of decarbonisation pathway adopted for any particular region. In general terms we anticipate that there may be more change between 2030 and 2050 than we expect in the period to 2030.

We anticipate:

Gas generation – Continued growth of gas generation capacity to support peak electricity demand as transport and elements of heat are electrified, especially at times when weather dependent renewable generation is not available.

Low carbon vehicles – we anticipate growth in the use of CNG and / or Hydrogen for vehicles as fuelling infrastructure is more established. Significant further growth in electric vehicles is expected post 2030. Up to 2030, the uptake of low carbon vehicles will only cover the initial adoption of vehicles. It is likely to be 2050 before all vehicles are low carbon.

Green Gas – many of the existing regulatory and legislative barriers to green gas injection including Hydrogen are likely to be resolved by 2030 so we expect the pace of growth to increase between then and 2050. By 2050 on a minimum demand day there could be over supply of green gas resulting in the need for significant compression and seasonal storage.

Wind generation – further growth is expected for both on and offshore wind generation post 2030 however the level of centralisation/decentralisation and on/offshore split is highly uncertain and will be dependent on the pathways in the period up to 2030 which may lead to changes to technology costs and feasibility such as deeper sea offshore wind.

Nuclear generation – longer term growth is expected from nuclear generation, particularly as a result of new nuclear technology such as small modular reactors. This will be largely dependent on the technology costs, policy and public acceptance

Solar PV – longer term growth is expected as technology costs reduce and the expectation of solar being more extensively integrated into building fabric.

Interconnectors – uptake beyond 2030 is uncertain as this will largely depend on electricity prices across Europe and the technology mix.

Other generation – it is expected that further sources of generation other than those mentioned above will be required, in particular gas generation with CCS technology and new developments for marine and tidal generation. The exact levels are uncertain as it will depend on the other technologies referenced above.

Electricity Storage – the ongoing growth in storage post 2030 is unclear as it will depend on the rate of uptake, technology developments and market arrangements.

Electrification of Heat – it is likely that policy or price drivers may incentivise the increased use of air source heat pumps between 2030 and 2050. Whether these are stand-alone or supported by gas boilers in a hybrid heating system, the impact on annual gas demand decrease is similar. In the case of ASHP as a sole appliance there would be a reduction in gas peak demand and an increase in DNO / generation requirement for peak heat. In the case of ASHP as part of a hybrid heating system the DNO / generation requirement is impacted to a lesser extend as the gas networks continue to provide the energy to meet peak heat.

Commercial Sector – Gas usage continues to decline marginally driven largely by offices, retail and health sectors due to the increased efficiency, shrinking commercial sectors and some uptake of new heating technologies. Peak electricity consumption is likely to decrease for traditional loads due to energy efficiency however this is likely to be offset due to large increases as a result of transport and heat/air-conditioning.

Industrial Sector – In the industrial sector, there will be a slight increase in annual and peak demand by 2030, driven by the mineral products, electrical engineering, food & drink, and paper & printing sectors. However overall by 2050, demand will decrease, with the biggest decreases seen in the food and drink and basic metals sectors (of 2.5% and 1.2% respectively by 2050). This decrease will be due to declining industrial output, energy efficiency improvements, and a shift away from gas boilers by 2050. HP uptake drives new gas demand at the generation level. Electricity consumption is less certain as not all processes will be capable of transferring to electricity due to high energy consumption. The role of demand response is also likely to play a major part, particularly depending on the level of diversity in energy sources which the industrial sector relies on.

In summary, we anticipate continued integration of the gas and power sectors, with reduction in use of gas as a fuel in some sectors. This will result in an equivalent increase in gas generation to deliver heat via electrical appliances. As gas demand becomes more volatile and with increased local gas production from green sources, it will be essential that we can operate our networks in a more flexible and dynamic way. This is likely to result in an increased need for investment in storage and compression.

2.3. Suggested use of this work

Due to the way this work has been derived, each key driver should be considered individually. On this basis each key driver acts as a core assumption that is indicative of the majority view of the licensees. When each licensee derives their own business plan from their analysis and stakeholder engagement, the common scenario can be used to compare the business plan to the common scenario. In the case of a large difference between the licensee’s view and the common scenario, the licensee should justify the difference.

3. Our approach

3.1. Scenario framework

The 2018 National Grid Future Energy Scenarios[2] (FES) were selected as the framework for this work. These scenarios are widely recognised across GB and used by Ofgem, BEIS as well as the network companies for planning purposes. Other scenario frameworks were considered but these did not have the same level of recognition or supporting data available that the group could access. In the development of the FES by the ESO, a comparison with other scenarios is undertaken as well as extensive engagement with stakeholders to ensure that these are credible. At a more local level there are alternative views of the future, which will be explored further in subsequent iterations of this work.

The FES scenarios are formed from a list of 70 assumptions[3], of which different combinations are used within each of the scenarios. Of the 70 assumptions that form the FES, these were reduced to 46 building blocks which licensees recognised as being relevant and had a direct impact on the gas and/or electricity network. For example, the amount of generation which connects to the electricity network will have a significant bearing on future planning assumptions, however other assumptions included in the FES will have a less direct impact such as the tax regime for different fuels (but may contribute to the more direct drivers selected).

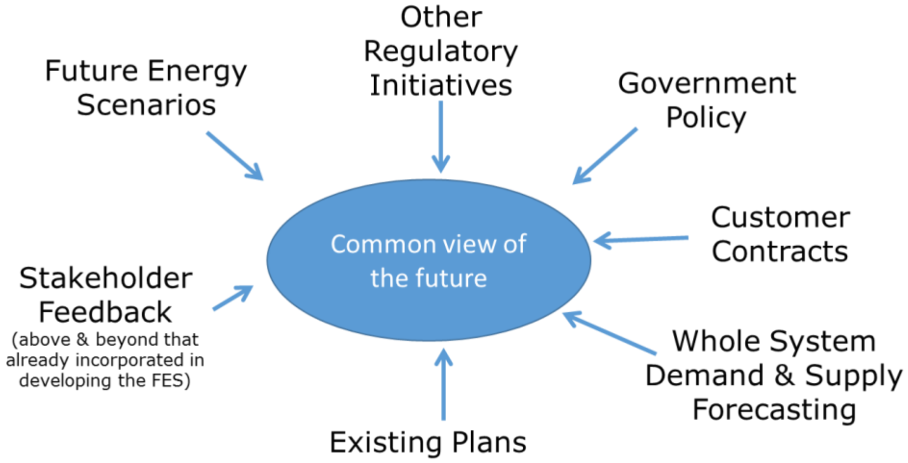
Consideration was also given to any assumptions which were not captured as part of the FES process yet licensees considered these to have a material impact. The role of small-scale gas generation and hydrogen did not feature strongly in the FES 2018 yet licensees are seeing greater interest in this. These two areas have been added to our analysis for completeness. It should be noted that several of the licensees are working with the FES team to develop the thinking on these areas for the 2019 publication.

From this list, a coordinated approach was taken to form a view on the out-turn position in 2030 across these relevant assumptions. 2030 was selected as being an appropriate timeframe as it encompasses the RIIO-2 period for all sectors and many targets are framed in this period. No formal view was taken beyond this due to the level of uncertainty. Each network licensee then provided a low/medium/high view on the expected position in 2030 for each of the building blocks. These views were informed by a range of factors shown in Figure 1:

[2] http://fes.nationalgrid.com/fes-document/

[3] http://fes.nationalgrid.com/media/1395/fes-2018-scenario-framework-assumptions_version-2.xlsx

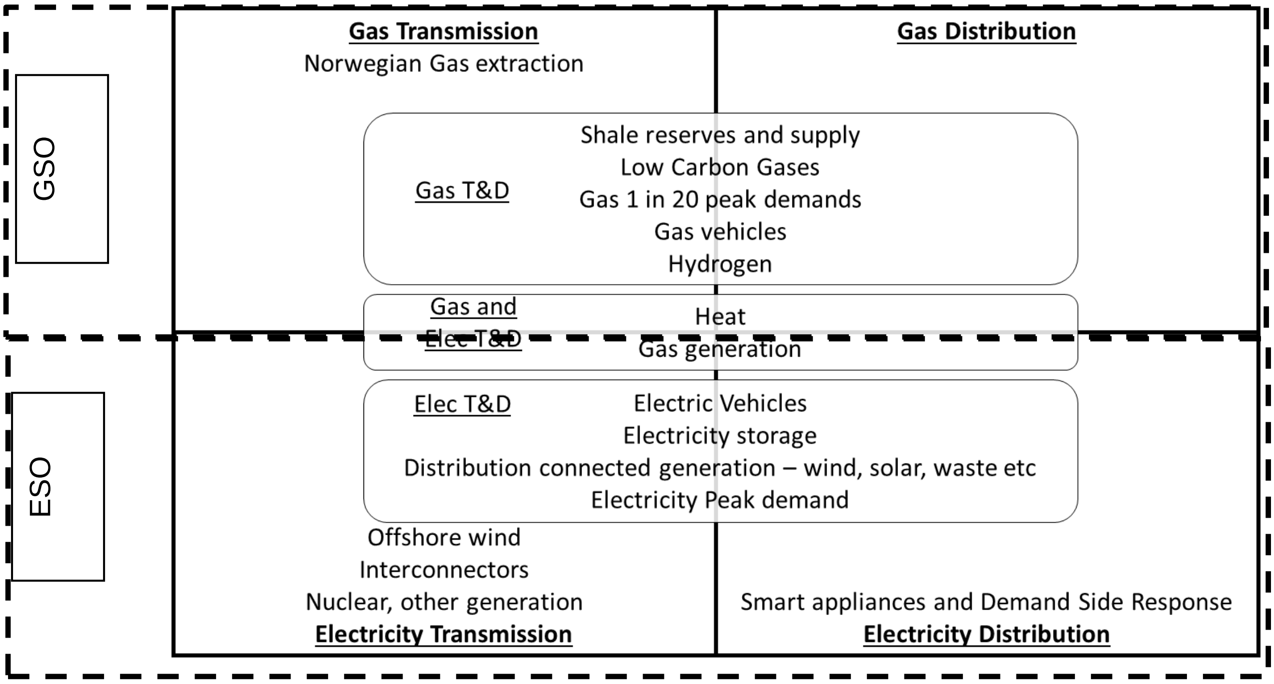
Figure 1. Factors influencing the common view of the future



Individual company views has been refined over the course of this work as the analysis has progressed (taking on board updated intelligence informed by stakeholder feedback) and through discussions between companies and across sectors.

The list of building blocks was then further consolidated on a per sector basis to those which have the most material impact on the sector's plans, these are seen as the key drivers and are outlined in this report. Cross reference has been made between sectors and a mapping undertaken to ensure a whole system approach is considered. For example, the trade-off between distribution and transmission connected renewable generation has been considered to ensure consistency. These key drivers and their cross-sector interactions are shown in Figure 2:

Figure 2. Key drivers and cross sector interactions

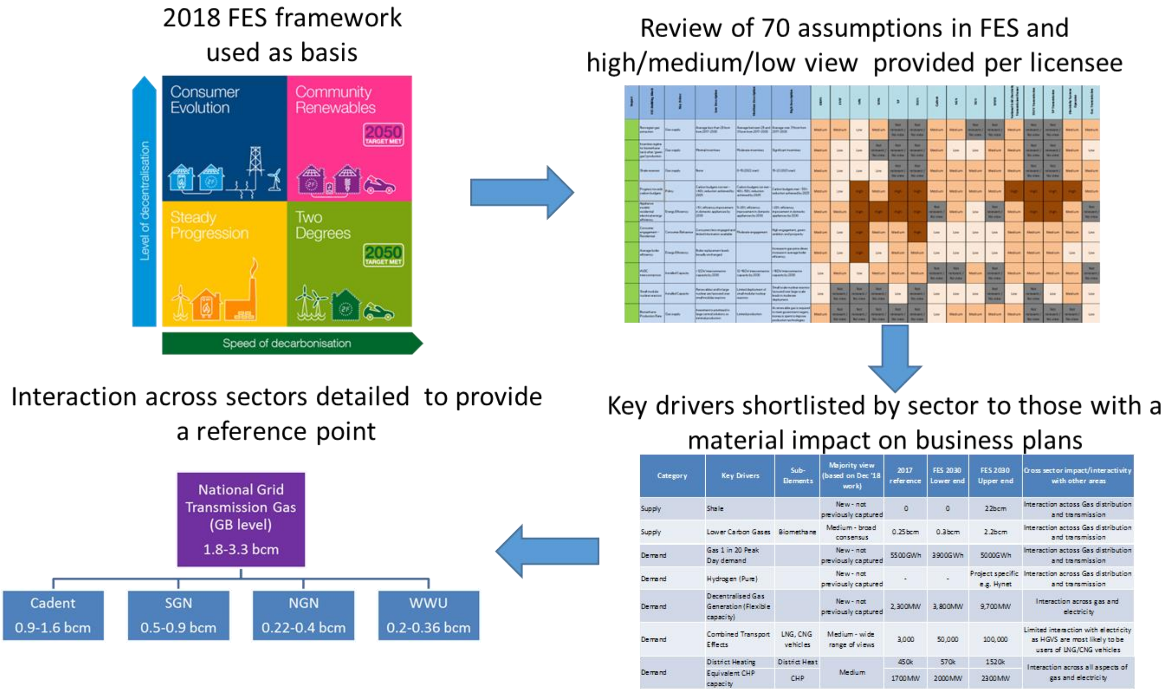


Against each of these key drivers, a common view has been formed on the level of uncertainty, interdependencies, the cost materiality as well as the expected range in 2030 by licensee. The pathway to 2030 will vary by key driver, as in some instances the change will be a decrease from today such as nuclear generation, while in others, there will be a significant increase, such as hydrogen uptake and EVs. Thoughts on the potential direction post 2030 have also been provided in the narrative for each of the building blocks. Views beyond 2030 are much more subjective due to the level of uncertainty and no quantification of these has been provided.

Where appropriate, the views of licensees directly impacted by the key drivers have been used to inform the projections for 2030, on the basis that those licensees will be planning for these and have access to information on the matter. Where a wide range of views were evident across the companies, the majority view has generally been used. In these instances, the range that is provided for 2030 is generally broader to reflect this level of uncertainty and wide range of views.

To accommodate regional differences, the 2030 view has been split by licensee group. This has allowed the regional differences to be easily distinguished such as the targets set by devolved governments which differ from national objectives. The use of historic data and other sources such as contracts have, for a number of areas, helped to inform the allocation of the common view across licensees. In a number of cases, where limited data is available or there are a range of different views, other proxies have been used such as customer numbers. An example of this is electric and gas vehicles. With such low volumes at present, projections per licensee are based on existing customer numbers rather than existing uptake which is very low. It is accepted that this may not be fully reflective of local ambitions, however each licensee will be able to justify any difference as part of their business plan development using other evidence which that have available.

Figure 3. Summary of process



4. Summary of key building blocks and interactivity

Key building blocks were identified by understanding which of the key drivers would have the most material impact on a company's business plan. In assessing the material impact, companies undertook an assessment of the potential interactivity across sectors and between drivers. The output of the interactivity assessment is presented in Figure 4. The analysis considered whether the building blocks either influenced, were dependant on, independent of or conflicted with other key building blocks. The analysis also took consideration of whether the interdependences were "weak" reflecting a second order effect.

Figure 4: Interdependencies matrix

	Key Driver	Installed Capacity			Gas supply		Energy Demand				Transport			Heat			Energy Efficiency	Smart	Consumer behaviour	Policy	Market drivers
Key Driver		RES capacity	Flexible capacity	Other capacity	Green Gas	Conventional Gas	Annual Elec demand	Peak Elec Demand	Annual gas demand	Peak gas Demand	EVs	Gas vehicles	Rail Electrification	HP	Gas / H2	Hydrogen with CCS	Energy Efficiency	Smart	Consumer behaviour	Policy	Market drivers
Installed Capacity	RES capacity		D	C			D	D			Dw		Dw	Dw			Dw		D	D	D
	Flexible capacity	D		C	Iw	Iw	D	D			Dw		Dw	Dw			Dw	Cw	Dw	D	D
	Other capacity	C	C				D	D			Dw		Dw	Dw		Dw	Dw		Dw	D	D
Gas supply	Green Gas		Dw			Cw			D	D		Dw			D	Dw	Dw		Dw	D	D
	Conventional Gas		Dw		Cw				D	D		Dw			D	Dw	Dw		Dw	D	D
Energy Demand	Annual Elec demand	I	I	I				I	C	Cw	D	Cw	Dw	D	Cw	C	D		D	Dw	D
	Peak Elec Demand	I	I	I						I	D		Dw	D	Cw		D	D	D	Dw	D
	Annual gas demand		D	Dw	I	I	C	Cw		I		D		C	D	D	D		D	D	D
	Peak gas Demand		D	Dw	I	I	Cw	Cw				D		C	D	D	D	Dw	D	D	D
Transport	EVs	Iw	Iw	Iw			I	I		I		C	Cw			Cw		Dw	D	Dw	D
	Gas vehicles				Iw	Iw	Cw		I	I	C		Cw	Cw		Dw			D	D	D
	Rail Electrification	Iw	Iw	Iw			Iw	Iw			Cw	Cw							Dw	D	Dw
Heat	HP	Iw	Iw	Iw	Cw	Cw	I	I	C	C		Cw			C	Cw	Dw	Dw	D	D	D
	Gas / H2				I	I			I	I				C		D			D	D	D
	Hydrogen with CCS			Iw	Iw	Iw	C		I	I	Cw	Iw		Cw	I				Dw	D	Dw
Energy Efficiency	Energy Efficiency	Iw	Iw	Iw	I	I	I	I	I	I				I				Dw	D	D	Dw
Smart	Smart		Cw					I		Iw	Iw			Iw			I		D	Dw	D
Consumer behaviour	Consumer behaviour	I	Iw	Iw	Iw	Iw	I	I	I	I	I	I	Iw	I	I	Iw	I	I		Iw	Dw
Policy	Policy	I	I	I	I	I	Iw	Iw	I	I	Iw	I	I	I	I	I	I	Iw	Cw		Cw
Market drivers	Market drivers	I	I	I	I	I	I	I	I	I	I	I	Iw	I	I	Iw	Iw	I	I	Cw	

Key	
BLANK	No interdependency
C	Conflicts with
D	Depends on
I	Influences
w	weak interaction

Read from the rows to the columns e.g. "Annual Elec demand depends on EVs"

From this matrix high-level insight was derived:

- Conflict around the total level of installed capacity
- Conflict around total volumes of energy (gas vs electricity v H2)
- Conflict around future of heat (gas vs electricity)
- Conflict around future of transport (H2/gas vs electricity vs rail)
- Energy landscape is heavily dependent on consumer behaviour, policy and market drivers
- Complex interactions between consumer behaviour, policy and market drivers

When the individual sectors undertook an assessment of the key building blocks that would impact their business plans, account was also taken of the interactivity with other drivers and sectors. For example, gas generation plants play an important role in balancing services to the power networks, effectively using storage in the gas networks to provide flexible distributed generation to the electricity network.

A summary of the key drivers and interactivity are presented for each sector in the tables below with further detail of each key driver and interactivity outlined later in this document.

Electricity Distribution

Category	Key Drivers	Sub-elements	Majority view (based on Dec '18 work)	2017 reference	FES 2030 Lower end	FES 2030 Upper end	Cross sector impact/interactivity with other areas
Generation	Wind Generation (GW)	Onshore and offshore distribution connected	Medium - wide range of views across companies	6.2	7.0	12.3	Interaction with electricity transmission DG
Generation	Solar Generation (GW)	Large, Small	Medium - wide range of views across companies	12.4	16.4	32.8	Interaction with electricity transmission DG
Generation	Distribution Thermal Generation (GW)	Waste, biomass, CHP	Medium - wide range of views across companies	6.8	9.2	13.0	Interaction with Gas as some generation will be supported by gas network
Flexibility	Domestic Demand side response at peak (GW)	Number of appliacnes, consumer engagement, V2G	Low/Medium - broad consensus	0.0	0.3	1.5	Interaction with electricity transmission Flexibility
Flexibility	I&C Demand side response at peak (GW)	Includes behind meter generation	Low - wide range of views	1.0	1.4	2.5	Interaction with electricity transmission flexibility
Flexibility	Storage (GW)	Domestic and distribution batteries	Medium - broad consensus	0.2	1.5	4.4	Interaction with electricity transmission batteries
Demand	Low carbon vehicles (m)	PEVs, PHEVs, Number (m)	High - broad consensus	0.06	2.7	10.6	Interaction with peak demand and electricity transmission
		Demand (GW)		0.10	2.6	8.1	
Demand	Heat (Number of installations ('000 properties))	Number of heat pumps, properties served by district heating	Low - broad consensus	488	1050	5440	Interaction across all aspects of gas and electricity
Demand	Underlying Peak demand (GW)	All demand, balancing and DG components	High - broad consensus	59.4	62.0	63.8	Aligned with transmission

Category	Key Drivers	Sub-Elements	Majority view (based on Dec '18 work)	2017 reference	FES 2030 Lower end	FES 2030 Upper end	Cross sector impact/interactivity with other areas
Supply	Shale		New - not previously captured	0	0	32bcm	Interaction across Gas distribution and transmission
Supply	Lower Carbon Gases	Biomethane	Medium - broad consensus	0.25bcm	0.3bcm	2.2bcm	Interaction across Gas distribution and transmission
Demand	Gas 1 in 20 Peak Day demand (incl. transmission loads)		New - not previously captured	5500GWh	3993GWh	5092GWh	Interaction across Gas distribution and transmission
Demand	Gas hourly peak demand (excludes transmission loads)		New - not previously captured	214			Interaction across Gas distribution and transmission
Demand	Hydrogen (Pure)		New - not previously captured	-	-	Project specific e.g. Hynet	Interaction across Gas distribution and transmission
Demand	Decentralised Gas Generation (Flexible capacity)		New - not previously captured	2,267MW	3,933MW	9,606MW	Interaction across gas and electricity
Demand	Combined Transport Effects	LNG, CNG vehicles	Medium - wide range of views	1,000	50,000	100,000	Limited interaction with electricity as HGVS are most likely to be users of LNG/CNG vehicles
Demand	District Heating	District Heat	Medium	450k	570k	1520k	Interaction across all aspects of gas and electricity
	Equivalent CHP capacity	CHP		1700MW	2000MW	2300MW	

Electricity Transmission

Category	Key Drivers	Sub-elements	Majority view (based on Dec '18 work)	2017 reference	FES 2030 Lower end	FES 2030 Upper end	Cross sector impact/interactivity with other areas
Generation	Offshore Wind (GW)	Transmission connected only	Medium - Broad consensus	5.3	16.1	29.1	No cross sector impact
Generation	Onshore wind (GW)	Transmission connected only	Medium - Broad consensus	6.1	9.3	12.4	Cross sector impact between Distribution and transmission connected wind
Generation	Nuclear (GW)	Large nucler only - note assumptions include closures as well as new build	Low - broad consensus	9.2	2.9	9	No cross sector impact
Generation	Distribution Connected Generation (GW)	Solar, waste, biomass, hydro	Medium - Broad consensus	19.5	27.5	49.9	Interaction with electricity distribution DG
Generation	Other Gen (GW)	Hydro, CCGT, Marine, CCS, Coal	Low - wide range of views	47.9	28.4	40.9	Interaction with Gas transmission for Gas fired generation
Flexibility	Interconnectors (GW)		Medium - Broad consensus	4	9.8	19.8	No cross sector impact
Flexibility	Storage	Pumped Hydro, transmission batteries and other transmission storage	Medium - Broad consensus	2.7	4	4.8	Interaction with electricity distribution batteries
Demand	Low Carbon Vehicles (m)	PEVs, PHEVs, Number (m)	High - broad consensus	0.06	2.67	10.62	Interaction with peak demand and electricity Distribution
		Demand (GW)		0.1	2.6	8.1	
Demand	Heat ('000 properties)	Number of heat pumps, properties served by district heating	Low - broad consensus	488	1050	5440	Interaction across all aspects of gas and electricity
Demand	Underlying Peak demand (GW)	All demand, balancing and DG components	High - broad consensus	59.4	62.0	63.8	Interaction with all demand and balancing elements

Gas Transmission

Category	Key Drivers	Sub-elements	Majority view (based on Dec '18 work)	2017 reference	FES 2030 Lower end	FES 2030 Upper end	Cross sector impact/interactivity with other areas
Supply	Shale Reserves (Supply from)		Medium	0	0	32bcm	Alignment with Gas Distribution
Supply	Norwegian Gas Extraction		Medium	35bcm	17bcm	32bcm	
Supply	Low Carbon Gas		Low	0.25bcm	0.3bcm	2.2bcm	Alignment with Gas Distribution
Demand	Gas Vehicles	CNG, LNG	Medium	1k	50k	100k	Alignment with Gas Distribution
Demand	Unabated Gas	CCGT, OCGT, CHP	High	35GW	31GW	43GW	Alignment with Electricity Transmission and Distribution
Demand	Gas 1 in 20 Peak Day demand		New - not previously captured	5500GWh	3993GWh	5092GWh	Interaction actoss Gas distribution and transmission

Energy System Operator

Key Drivers	Sub-Elements	Majority View (based on Dec '18 work)	2017 reference	2030 FES Lower end	2030 FES upper end	Cross sector impact/interactivity with other areas
Consumer Behaviour	Energy efficiency, consumer engagement	Low/Medium - broad consensus	Qualitative	Low engagement	Moderate level of engagement	All demand elements in Gas and Electricity
Decarbonisation of electricity supply (GW)	Installed capacity - all generation types	Low / medium - Broad consensus	103	131	161	Interaction across all aspects of gas and electricity
Heat ('000 properties)	Number of heat pumps, properties served by district heating	Low - broad consensus	488	1050	5440	Interaction across all aspects of gas and electricity
Distribution Connected Generation (GW)	Solar, waste, biomass, hydro	Medium - Broad consensus	19	27	50	Interaction with electricity distribution DG
Demand side response at peak (GW)	Domestic and I&C DST, TOUT	Low/medium - wide range of views across companies	1.0	1.7	4.0	
Digitalisation and 'big data'	Smart meters	Medium - Broad consensus	2.5m		24 million installations by 2021 to 2023	Interaction across all aspects of gas and electricity
Low Carbon Vehicles (m)	PEVs, PHEVs, Number (m)	High - broad consensus	0.06	2.68	10.63	Interaction with peak demand and electricity Distribution
	Demand (GW)		0.1	2.6	8.1	
Storage (GW)	Batteries, pump storage an other technologies	Medium - Broad consensus	2.7	5.9	9	Interaction with storage assumptions in all sectors
Policy and governance	Energy efficiency policy, decarbonisation targets	N/A	N/A	N/A	N/A	Interaction across all aspects of gas and electricity

5. Uncertainty

The energy industry is currently undergoing significant change through the decarbonisation, decentralisation and digitalisation of the GB energy system. While the advent of this significant change may be more certain, the technologies which will deliver these changes and timings of them can be very uncertain.

When considering uncertainty, we look across the three sectors of **heat, transport** and **power (generation and demand).** Again, within these sectors there are areas of more of less uncertainty. In determining how uncertain an area is we look at three key indicators:

- **Policy** – Is there a policy in place to realise this area's ambition at EU, national and regional level?
- **Funding –** Is there a funding and/or incentive mechanism for this area, either via government support or investor confidence?
- **Stakeholder –** The level of support from stakeholders for a change to occur, whilst noting more expert views in certain areas.

Heat – Policy, at a national and regional level, for decarbonising heat is still in development and it is expected that, consumer choice will play a major part in shaping policy. The recent Spring Statement by the Chancellor of the Exchequer that fossil fuel heating will be banned from all new homes from 2025 is evidence of this developing policy landscape. Equally, there are limited funding and/or incentive mechanisms for low carbon heat when compared to other areas such as Renewables Obligations. This uncertainty is further reflected in stakeholder feedback, where numerous solutions for decarbonising heat are proposed and indeed some which propose it is not decarbonised. As a result of the differing views around heat policy this was a key area of focus in the recent Gas Demand Forecasting project – collaborative across all gas distribution networks. High level results on likely technology uptake are provided later in the document.

Transport – This is widely recognised to be an area which is changing rapidly. At a national level, a target has been set for no new petrol or diesel cars to be sold by 2040, while different regions have more ambitious targets such as Scotland, London and other areas which may drive a faster uptake in some areas. There are policies and funding in place for some areas for decarbonising transport – such EV subsidy in addition to market forces are a major factor in the transition. This gives some degree of certainty in this area, in particular around EVs and this is further supported by broad stakeholder support here.

There is greater uncertainty around the longer-term role of hydrogen and consumer behaviours around EV charging which have a wider whole system impact. This leads us to conclude that the direction of travel with respect to Transport is an area of more certainty, compared to say heat, particularly in some areas e.g. domestic EV uptake but less in others e.g. gas/hydrogen vehicles, which is reflected in the following key technologies:

- Pure Electric Vehicles
- Plug-in Hybrid Electric Vehicles
- Natural Gas Vehicles

- Hydrogen Vehicles

There are natural interdependencies between these technologies and conventional transport technologies, which needs to be reflected to ensure a sensible mix is represented.

Electricity Generation – There is wide acknowledgement that the GB energy system has undergone rapid decarbonisation over the last ten years. This trend is highly likely to continue, with strong policies and funding in place to achieve this ambition. The uncertainty is around what technologies will deliver this ambition and whether they are connected to the distribution or transmission networks. Further to this stakeholder feedback here is varied as to the technology mix expected by 2030. This leads us to conclude that there is uncertainty around the future technology mix, but more certainty around the low carbon nature of this mix. Which is reflected in the following key technologies:

- Wind – Onshore and Offshore – distribution and transmission
- Solar
- Thermal generation – distribution and transmission (providing flexibility to support decarbonisation)
- Nuclear
- Storage (providing flexibility to support decarbonisation)
- Interconnectors (providing flexibility to support decarbonisation)

There are natural interdependencies between these technologies, which needs to be reflected to ensure a sensible mix of technologies is represented.

6. Expenditure

6.1. Licensee expenditure over the current RIIO1 price control

The RIIO1 price controls were set in 2013 for the gas distribution, electricity transmission and gas transmission licensees. The electricity distribution licensees had their RIIO1 price control set in 2015. The RIIO1 controls run for eight years. At the time of setting RIIO1, the ESO and its associated allowances, were part of NGET. From April 2019 the ESO will become a legally separate business under the National Grid group and from April 2021 it will have its own price control under RIIO-2. For comparison, the ESO costs around £182m per year in order to undertake its role today.

The tables below provide a high level overview of the average annual and total forecast expenditure for each of the licensees, as reported in Ofgem's recent 2017/18 annual reports.

DNO Group	RIIO1 average annual expenditure £m	RIIO1 total forecast expenditure £m
ENWL	246	1,964
NPg	421	3,367
WPD	970	7,763
UKPN	734	5,868
SPEN	447	3,577
SSEN	468	3,747
Total	**3,286**	**26,287**

GDN	RIIO1 average annual expenditure £m	RIIO1 total forecast expenditure £m
East of England	335	2,678
North London	273	2,186
North West	237	1,897
West Midlands	172	1,376
Northern	235	1,881
Scotland	176	1,411
Southern	371	2,969
Wales and West	218	1,746
Total	**2,018**	**16,144**

Note: Figures in 2017/18 prices

Electricity Transmission
Approximately 45% of all expenditure in T1 is due to load related activity. These numbers are based on the Ofgem annual report for electricity transmission 2017/18. These numbers are the actual expenditure to date and forecast for the remainder of the period in 2017/18 prices.

It should be noted that of the 45%, a substantial amount of this is due to the Western Link HVDC project. It is anticipated that in T2, a number of similar large scale infrastructure projects will be required which are identified through the annual Network Options Assessment (NOA) process and is a much more rigorous analysis of options that are required to address system requirements. The NOA process applies a least worst regrets approach to evaluating expenditure using the FES which is beyond the scope of this work. In RIIO-T2, there are number of major projects which are being developed through this process and we would not consider the common scenario to be relevant to these. Example projects are:

- Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC
- Eastern Scotland to England link: Peterhead to Drax offshore HVDC
- New transmission line between South London and South Coast of England

A full list of projects which are proceeding under NOA can be found at:
https://www.nationalgrideso.com/insights/network-options-assessment-noa

	Load related (£m, 17/18 prices)	Other (Non-load, non-op capex, Opex) (£m, 17/18 prices)	Total (£m, 17/18 prices)	Load %
SPT	1,159	1,033	2,192	53%
SHET	2,696	699	3,395	79%
NGET	3,330	7,035	10,365	32%
Total	**7,185**	**8,767**	**15,952**	**45%**

All data taken from Ofgem annual report 2017/8, values are actuals and forecast expenditure for T1 period.

6.2. How costs are covered – user bills or connection charges

Costs relating to the operation and maintenance of electricity networks are funded through the use of system charges namely: BSUoS – Balancing Services Use of System; TNUoS – Transmission Network Use of System; and DUoS – Distribution Use of System charges. These charges make up around a quarter of a domestic customer's electricity bill.

How network costs are funded for reinforcement can differ depending on the sector and the driver for investment but in all cases frameworks are in place with the objective of making sure that customers have fair access to the network and pay an appropriate proportion of any work depending on who will benefit and how much revenue will be recovered from their ongoing charges. Although the terms used are different in gas and electricity the approaches are very similar.

Ofgem are currently looking at several areas of reform which will impact the way in which these costs are recovered from customers. These reforms aim to make charges more cost-reflective both in terms of the locational impact and the time of use, with the aim of encouraging a flexible and efficient use of the system.

6.3. Range of solutions to deal with requirements e.g. flexibility

The totex regulatory framework in RIIO-1 encourages network companies to deliver their outputs and licence obligations at the lowest cost by removing any bias between capital and operating expenditure. Importantly, any cost saving or cost overrun compared to set allowances is shared between companies and customers, meaning there is an equivalent risk and reward profile. This framework ensures that range of options such as traditional network solutions can compete on a level-playing field with new, innovative non-network solutions. For example, this removal of any capex bias through totex has enabled new flexibility markets to develop, whereby flexible distributed energy resources (DER) can negate or defer the need for some traditional reinforcement – providing customers with the same high-levels of service but at reduced cost.

6.4. Co-ordinating system solutions – cross sector approach

A key question raised by the CG has been how are licensees working together to ensure that customers do not fund multiple solutions to the same problem. This cross sector work has brought licensees together and facilitated sharing of future views and potential network impacts in a manner not previously seen before. This level of co-operation and transparency is enabling licensees to better shape their upcoming RIIO-2 submissions as well as inform the potential uncertainty mechanisms that will play a major role in facilitating the transfer of funding to those sectors and licensees which are best placed to meet consumers' needs efficiently in the coming period. In future iterations of this work it expected that licensees will review and update projections for the latest available evidence. This will be a crucial activity ahead of the RIIO-ED2 submissions, given the likely pace and scale of change we will undoubtedly witness in the intervening two years.

7. Glossary

DNO Map

GDN Map

DNO group	DNOs	Customers	Network length (km)
ENWL	**ENWL**	**2,383,887**	**57,324**
NPG	NPgN	1,602,128	41,705
	NPgY	2,298,786	54,319
Total		**3,900,914**	**96,024**
WPD	WMID	2,481,944	64,879
	EMID	2,647,059	73,745
	SWALES	1,133,101	35,679
	SWEST	1,613,218	50,610
Total		**7,875,322**	**224,913**
UKPN	LPN	2,345,807	37,160
	SPN	2,296,864	53,015
	EPN	3,627,858	97,817
Total		**8,270,529**	**187,992**
SP	SPD	2,007,341	58,515
	SPMW	1,512,961	47,051
Total		**3,520,302**	**105,567**
SSE	SSEH	772,984	49,154
	SSES	3,049,924	77,487
Total		**3,822,908**	**126,641**

GDN group	GDNs	Customers	Network length (km)
Cadent	East of England (EoE)	4,011,239	51,780
	North London (Lon)	2,273,731	20,931
	North West (NW)	2,687,832	34,190
	West Midlands (WM)	1,961,381	24,210
Total		**10,934,183**	**131,111**
NGN	Northern (NGN)	2,534,107	36,116
SGN	Scotland (Sc)	1,826,133	24,917
	Southern (So)	4,103,996	49,860
Total		**5,930,129**	**74,777**
WWU	Wales and West (WWU)	2,532,039	35,000

8. Key drivers

The following key drivers are those identified.

Supply related drivers

1. Gas Generation

Overview
In recent years the GDNs have seen a rapid increase in the numbers of enquiries and connections for small-scale, distribution connected gas generation. At the same time a significant amount of gas generation, equating on average for around 40% of GB power generation, is connected on the National Transmission System (NTS). Whilst only a small number of connections have been connected during RIIO-1 to the NTS, there continues to be ongoing enquiries for new connections.

Uncertainty
All of the GDNs have seen unprecedented growth in this area during RIIO-1 with a specific example from WWU being provided. There is some uncertainty in the future based on what else is happening in the generation mix. Where gas generation is needed to provide base load e.g. if growth to the nuclear sector does not materialise, then some new large CCGT sites are likely to be needed to meet future demand requirements. Where gas generation is required to provide flexibility in response to the growth in renewables, we anticipate the focus to be on smaller flexible generation. In both cases the load factor of the generation is likely to be different to what we see today.

Interdependencies
There are strong interdependencies with other building elements across several areas:

- Growth in electricity demand and hence generation requirements as anticipated from the increased charging requirements of EVs , any increase in electricity usage for heat and other appliances
- Shortfalls in the availability of secure electricity generating requirements as the coal and nuclear fleet decline and are replaced with growth in weather dependent generation
- Profitability of generation contracts
- The level of penetration of energy storage technologies that would provide competition for revenue streams (e.g. flexibility).

Regional allocation method
The GB view taken from FES 2018 and allocated by the percentage of customers served by each GDN with transmission volumes being an aggregation of GDN values and the transmission directly connected sites (the GB level).

Cost materiality
A low cost materiality was indicated across the networks for this building block. Currently the costs associated with the connection of sites are borne by the developer and not the network. Any reinforcement to the network itself is also subject to economic tests such that the developer usually pays an appropriate proportion. The networks will keep their charging arrangements under review to ensure the charges for gas generation are appropriately cost reflective; taking account of market conditions and whole-systems impacts.

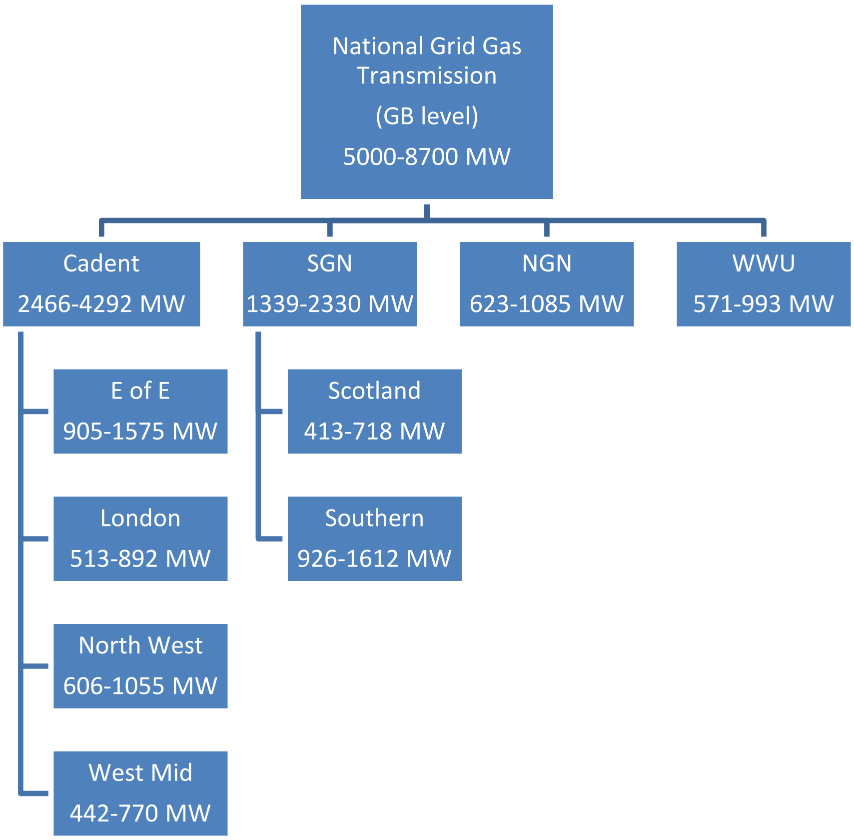
Position today and by 2030 from FES 2018 (excluding CHP)

Gas Generation excl. CHP Capacity (MW)	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017
Decentralised	9,163	3,949	3,933	9,606	2,267
Transmission	18,962	24,090	33,790	29,736	29,181

*Decentralised/Transmission refers to the electricity rather than gas networks

The majority view was medium: between 20 GW and 32 GW capacity by 2030 this is decentralised and centralised in totality

The chart below focuses on the decentralised gas generation element which was identified as a key driver by gas distribution networks during the RIIO-2 period.

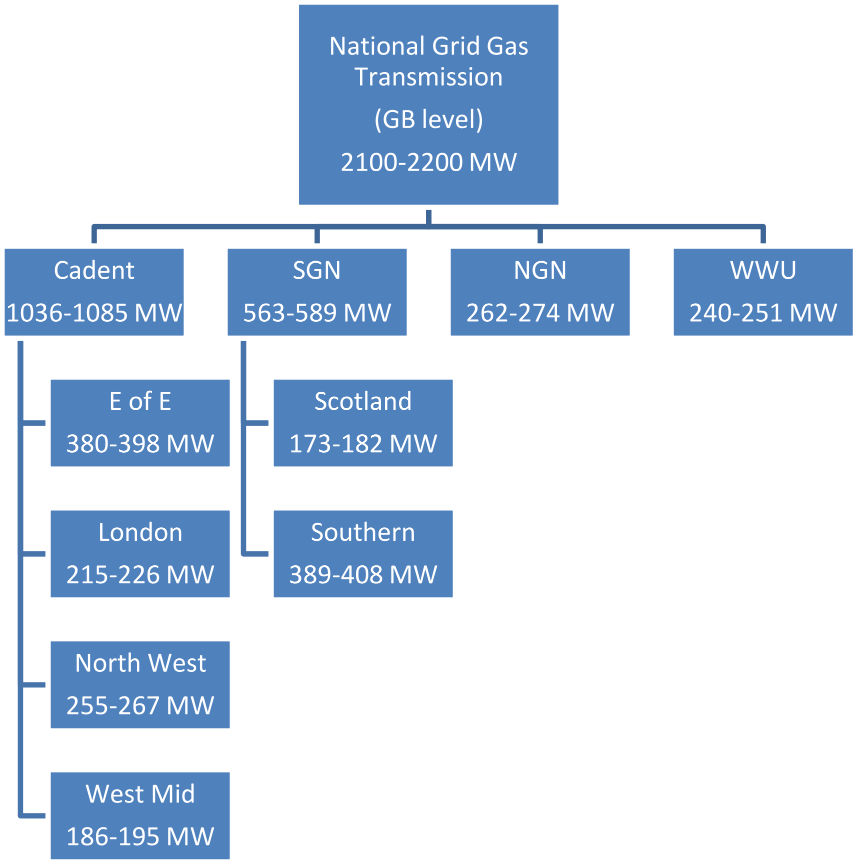


Position today and by 2030 from FES 2018 (CHP only)

Capacity (MW)	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017
Decentralised	2,022	2,320	2,016	2,169	1,691
Transmission	1,509	307	1,683	1,683	1,808

*Decentralised / Transmission refers to the electricity rather than gas networks

The majority view was medium: between 2.1 GW and 2.2 GW capacity by 2030
The chart below focuses on the decentralised CHP element which was seen as a key driver by gas distribution networks during the RIIO-2 period. Recent stakeholder engagement conducted by one of the GDNs is confirming the use of CHP to avoid grid connection charges and as a means of avoiding peak electricity tariffs and potentially offering DSR.



2. Nuclear Generation

Overview
The future level of Nuclear generation in GB is largely dependent upon the expected life of existing plant and regional and national government backing of new nuclear plant. Due to the scale and nature of the generation, all new nuclear sites are expected to connect to the transmission network.

Uncertainty
The life expectancy of the current nuclear fleet is largely dependent upon both the condition of irreplaceable components, such as graphite cores and boilers, which are subject to extreme conditions involving high temperatures, pressures and radiation exposure. Life-extensions are regulated by the Office of Nuclear Regulation (ONR), and will only be permitted if deemed safe. Recent issues with cracks in the graphite core of some reactors, may indicate limited opportunity for further life-extensions of the existing fleet, should the ONR not relax its existing safety policy.

New nuclear is largely dependent upon government support, through up front agreement of Contracts for Difference or other funding support. To date only one project (Hinkley Point C, due to connect in 2025) has secured funding, with two other projects (at Wylfa and Moorside) being suspended. Whilst the existing UK government supports the development of new nuclear in principle, the Scottish Government are opposed to new nuclear in Scotland.

Interdependencies
Nuclear generation has traditionally been used to meet baseload demand requirements, fulfilling at in excess of 20% of GB demand. Once the existing fleet decommissions, there will be a need for other generation to replace it to meet demand requirements. This is likely to take the form of thermal generation, such as large CCGTs or biomass, should new nuclear beyond that under construction not be deployed.

Regional allocation method
Given the scale and nature of the generation and Scottish Government policy, all new nuclear sites are expected to connect to the Transmission network in England and Wales.

Cost materiality
A high cost materiality was indicated across the networks for this building block. As nuclear generation is very large scale and requires a large water supply, they tend to be situated on the coast, away from traditional large demand centres. This means that they are expected to trigger large transmission investments, such as new substations and overhead lines.
Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
2.9GW	9.0GW	2.9GW	9.0GW	9.2GW

The majority view was low: less than 7GW connected by **2035**. Given the existing situation, is likely that only one new sites connect by 2030. Assuming no additional life extensions on top of what has already been agreed, it is likely that only one of the existing fleet will be operational in winter 2030. This results in an expected level of capacity of 4.6GW in 2030, distributed as shown in the following diagram:

3. Wind Generation

Overview
The future level of growth GB in wind generation is largely dependent upon regional and national government policies for energy and planning.

Uncertainty
For onshore wind policy varies between UK, Welsh, and Scottish governments. For example, whilst the Scottish Government is a strong advocate of onshore wind, the UK government's energy policy has moved away from subsidising new onshore wind capacity, despite being a low-cost option compared to other renewable technologies. This could impact the number of projects that could proceed nationwide. Planning policy also differs regionally. For example, many onshore wind developers facing greater difficulties in obtaining planning permission in England than in Scotland.

The UK government‘s policy on offshore wind is much more favourable, with the recent announcement of a sector deal and a target of 30GW being installed in GB by 2030. This in combination with rapid cost reductions in the technology over recent years is likely to result in strong growth, depending on the availability of future seabed leasing and wider market factors.

Interdependencies
The level of wind capacity installed could impact/be impacted by the level of penetration observed in other low carbon technologies (e.g. solar PV and nuclear).

Regional allocation method
For onshore wind, it is more likely that transmission level connections by will occur in Scotland than England or Wales. This is due to a combination of UK government planning policy (England) and the location of transmission connected projects proposed to date. This has been reflected in the FES ranges, which have been used to allocate transmission connected projects regionally.

For distribution level onshore wind projects, where planning permission may be easier to obtain, onshore wind is still likely to be regionally located in areas where it is looked upon favourably by the local planning authorities. To allocate future projects, the existing split of installed capacity (of both onshore and offshore wind) across areas has been used. At a distribution level, this work has also highlighted additional dialogue that is required between licensees and the ESO to ensure that the FES fully captures all distribution connected wind resources. At present, the numbers for distribution connected wind are on the low side.

For offshore wind, at this stage it is expected that future projects will be purely transmission connected, and has been allocated regionally based on FES data, based on known projects.

Cost materiality

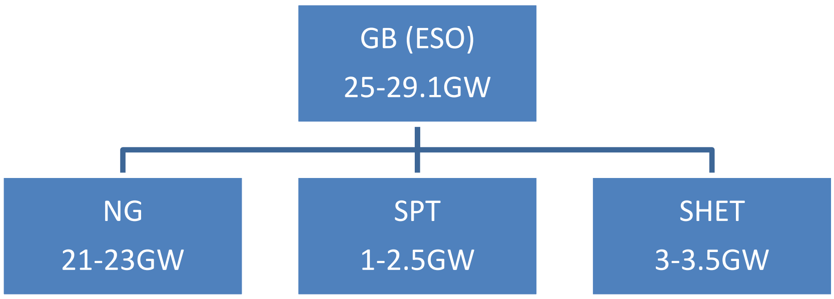
A high cost materiality was indicated across the networks for these building blocks. The likely location of onshore wind in Scotland could lead to requirements for wider transmission network reinforcements to transfer energy to demand centres in the South. This is in additional to more localised works, which may require new transmission or distribution build in remote locations. For offshore wind, its location on the edge of the transmission network, can drive the need for large reinforcements of the network involving new circuits and/or substations.

Position today and by 2030 from FES 2018

Connection	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
Transmission (Onshore)	11.9GW	12.4GW	9.3GW	10.9GW	6.1GW
Distribution (Onshore)	11.5GW	7.1GW	6.2GW	9.6GW	5.4GW
Transmission (Offshore)	22.8GW	29.1GW	24.0GW	16.1GW	5.3GW
Distribution (Offshore)	0.8GW	0.8GW	0.8GW	0.8GW	0.8GW

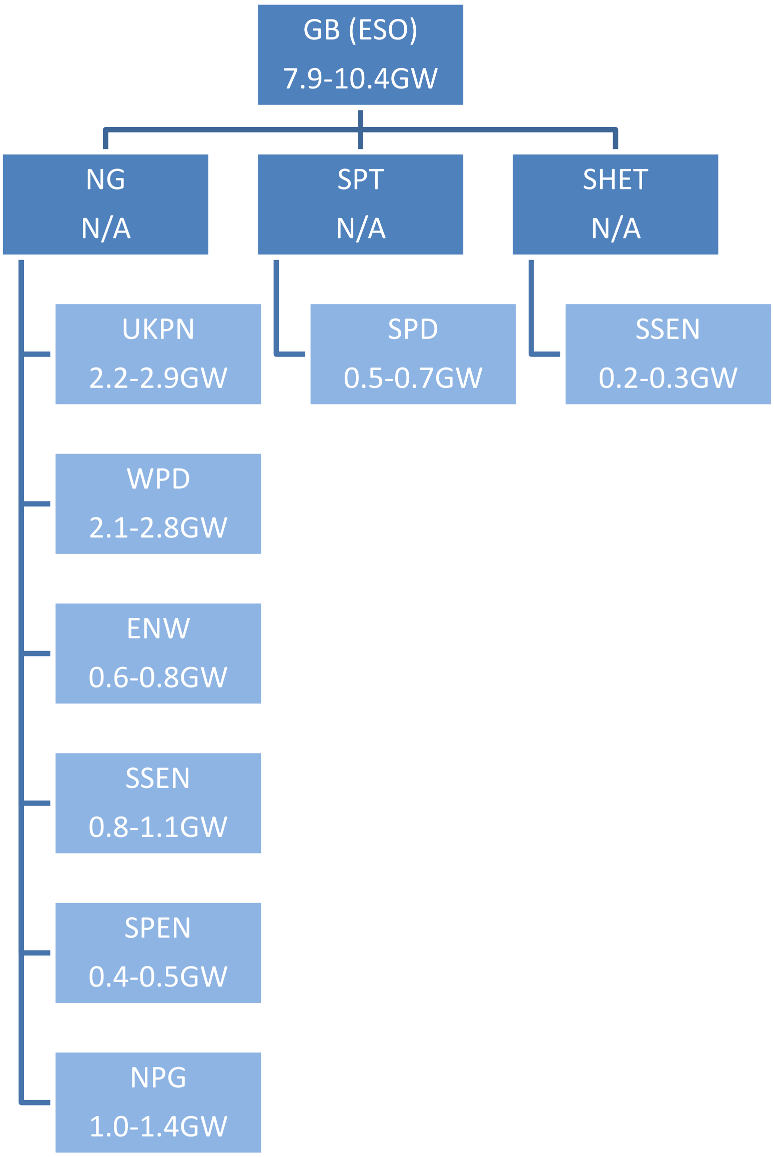
The majority view was **high** for transmission connected offshore wind and **medium** for both distribution and transmission connected onshore wind, depicted in the following diagrams:

Offshore Wind (transmission connected):



Onshore wind (transmission connected):

Onshore and offshore wind (distribution connected):



4. Solar PV

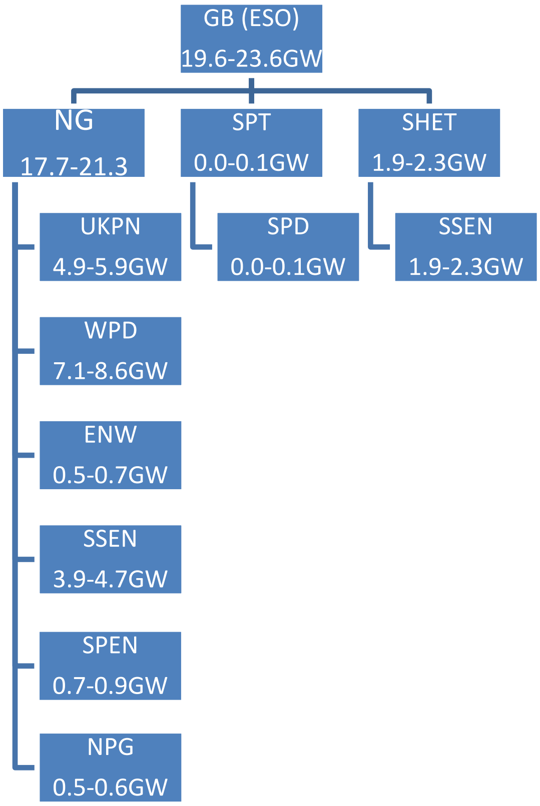
The installed capacity of solar PV across Great Britain was 12.4 GW in 2018. By 2030 the National Grid FES show that the range of total PV installations will be from 16.4 to 32.8 GW. Based on the majority view of network companies, the common view has considered the medium nationwide trend of the FES for solar PV. This equates to a 19.6 to 23.6 GW range by 2030.

Falling capital cost of PV installations, coordinated operation with battery storage and government policies supporting a low carbon future should be listed among the key factors driving the increased use of solar energy. Future PV installations are expected to pose challenges in balancing network capacity in parts of the distribution networks, as well as increase fault levels and breaches of voltage limits (especially on networks below the major substation level). At the same time they are expected to reduce electricity demand supplied by transmission networks. In the long run this could potentially move minimum demand periods during afternoon hours, which can result in voltage control challenges at a transmission level.

Regional allocation method
Allocation is based on the existing capacity of PV installations per DNO license area.

Solar PV scenarios:

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017
32.8 GW	23.6 GW	16.4 GW	19.6 GW	12.4 GW



5. Interconnectors

Overview
There are currently 4GW of interconnection between mainland GB and Europe/Ireland. A number of additional projects are under construction or planned for the next ten years.

Uncertainty
The projections which have been forecast are based on known projects which are in construction or have applied for a connection and are realistically likely to connect by 2030. Many of these projects have a long lead time for planning and design therefore it is unlikely that a significant number of new projects will emerge in this period.

Interconnector developers have an option to opt for its revenues to be regulated through a “cap and floor” regime. This defines a maximum and minimum revenue that can be earned through the operation of the interconnector in each year. Whilst this limits potential returns, it significantly lowers the level of risk developers face, making investment more attractive.

Interdependencies
The need for interconnectors is partly interdependent on the generation landscape in GB and connected markets, however this is viewed as a low risk.

Where energy prices differ between markets, participants will seek to flow energy between countries to benefit from the price differential. Ultimately, this could influence the need for generation in either country, but this would depend on other factors such as security of supply policy and future needs for flexibility.

Regional allocation method
Capacity allocation based on known projects which are contracted/in construction.

Cost materiality
High. Depending on the nature of the connection, costs associated with the point of connection for the interconnector, may be largely borne by the connecting party through connection charges.

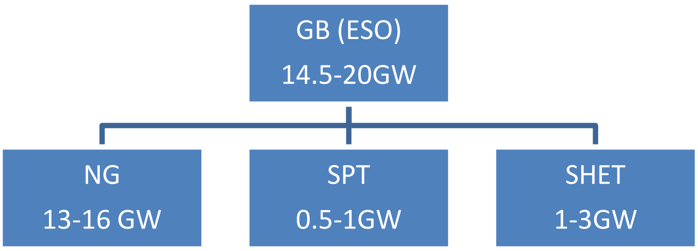
Other reinforcement costs may be significant due to interconnector’s location on the boundary of the system, and their ability to operate both on import and export modes leading to potential for additional capacity upgrades being required to allow power to be transferred across GB system. These costs will be socialised, because unlike generation, interconnectors are not liable for charges for their use of the Transmission network.

Interconnectors scenarios:

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017
16.5 GW	19.8GW	15.1GW	9.8GW	3.95GW

Longer term impact: FES assumes limited further uptake beyond 20GW – dependant on generation make-up in UK and Europe longer term and prices across Europe if this is attractive.

Common view
Broad consensus of high uptake based on known projects: 14.5-20GW by 2030



6. Other Generation – transmission connected

Overview
CCGT, OCGT, Coal, CHP, Biomass, Hydro, Marine and CCS. Over this period, there is a combination of plant closures (Coal – 12 GW, CCGT and OCGT) as well as new plant assumed to connect to the system which is why the range extends is below the current position. Around 80% of the 2030 scenarios are from gas fuelled generation.

Uncertainty
These technologies are dependent on technology advancements (e.g. marine and CCS) but this proportion is very low. Fossil fuel generation is subject to changes in emissions policies and other incentives such as the capacity market for new generation to connect to the system.

Interdependencies
Interaction with Gas Transmission which will also be required to provide points of connection for new gas fuelled generation.

Regional allocation methodology
Capacity allocation based on known projects which are contracted/in construction.

Cost materiality
Medium. Depending on the nature of the connection and where it is in the country, a large proportion of costs associated with the point of connection, may be borne by the connecting party. Other reinforcement costs will be socialised through Use of System charges (part of which will be paid by the generator) and will be heavily dependent on location but in most instances generation will be located closer to demand thus mitigating the reinforcement costs.

Generation scenarios:

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017
28.4 GW	36.6 GW	40.9 GW	35.3GW	47.9 GW

Beyond 2030, there is a wide range of uncertainty as additional gas generation may be required dependant on nuclear, wind and storage scenarios to meet controllable and peak requirements. Wide range of longer term views as this will also depend on gas prices, carbon price and CCS maturity.

Common view
Medium view equates to 30-36GW in 2030. Gas fired generation accounts for majority of generation. There is a wide range of views across the companies, in particular a split between Scotland/England and Wales. Most growth in Scotland is due to hydro generation but this is relatively low in comparison to other areas.

7. Shale

Overview
Significant sources of methane in the form of shale gas exist in particular rock formations, predominantly in the North. Initial exploratory wells are currently being developed and tested to ascertain whether the gas can be extracted safely and economically. The performance at these sites will drive the future for the shale gas sector, which could supply a very large proportion of the UK's gas demand in the coming decades, which would reduce the levels of imported energy.

Uncertainty
There are a number of major uncertainties associated with shale gas extraction, including political, public attitude, with the potential for regional variations. There are also technical and economic practicalities, and any environmental incidents could delay or even destroy the sector.

The extent of shale extraction will depend on the performance of the test wells, over the next 12-24 months, with the first large scale test connecting in Cadent's NW network. Early indications are very positive in term of the gas quality, quantity and rate of extraction. There is also uncertainty as to whether the gas connects to the distribution of transmission networks. However, in either case, there are connection processes that apply, where the costs are borne by the developer.

Interdependencies
There are no strong interdependencies although higher indigenous levels of gas supply would displace imported gas.

Regional allocation method
The allocation method is based on the current areas of shale gas exploration and known potential, mindful of regional government controls.

Cost materiality
A high cost materiality was indicated across the networks for this building block. This reflected the potential investment costs for the networks in accommodating very large quantities of gas, with connection likely at the higher pressure tiers to meet capacity and gas quality requirements.

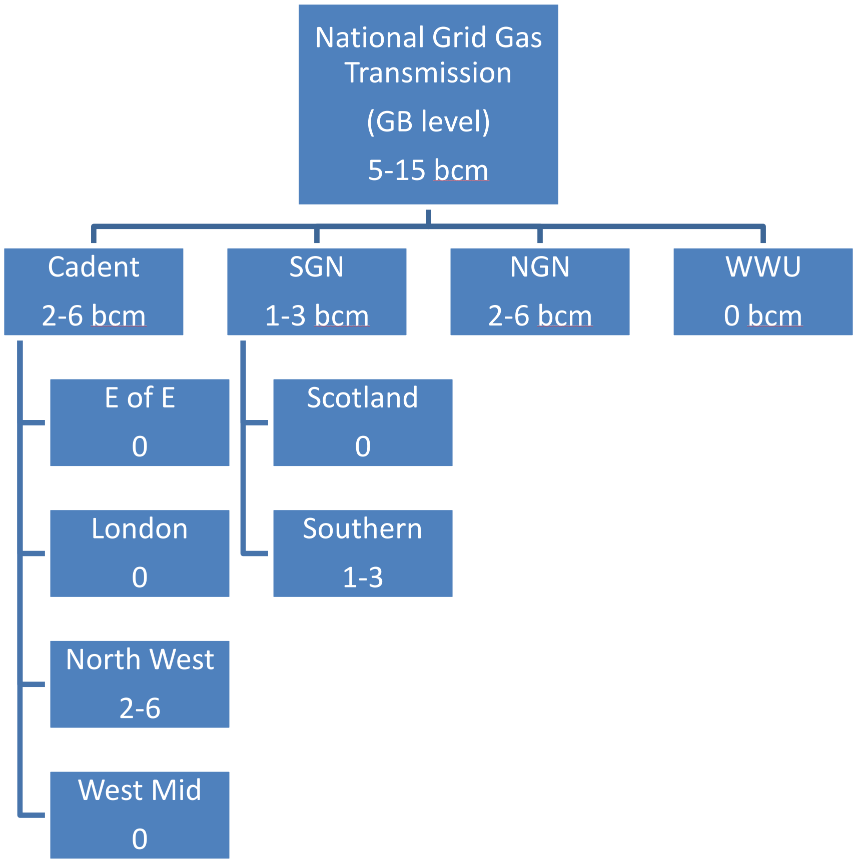
Currently most of the costs associated with the connection of an entry site are borne by the

developer and not the network. How network charges deal with gas entry investments may be reviewed as increasing levels of entry gas are connected to the distribution networks.
Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
0 bcm*	10 bcm	32 bcm	10 bcm	0 bcm

*bcm – billion cubic meters

The majority view was medium: 5-15bcm of shale gas by 2030 with the following regional breakdown (all figures in bcm):



8. Low Carbon Gases

Overview
FES groups together, under the green gas category, biomethane and bioSNG. Biomethane is produced principally by anaerobic digestion (AD) of organic material, either waste products or crops grown for this purpose. There is an expectation that several new AD installations will come on line every year until 2030. BioSNG technology is being developed to produce gas from household waste and should be able to produce gas on a larger scale than AD.
Both sources will predominantly supply gas directly to the low-pressure distribution networks rather than to the transmission network, however there has been recent interest in the connection of a number of sites to the transmission network.

Uncertainty
The stimulus for the biomethane market in GB was driven by the Renewable Heat Incentive RHI that is predicted to come to an end in 2021, the current RHI does not include BioSNG. There is some uncertainty as to whether this incentive will continue beyond this date or an alternative made available. If an incentive is not in place this could have an impact in bringing new sites to market. On a positive note the Chancellors Spring Statement 2019 indicated the governments wish to ‘accelerate the decarbonisation of gas supplies by increasing the proportion of green gas in the grid’.

Interdependencies
There are no strong interdependencies with other building elements.

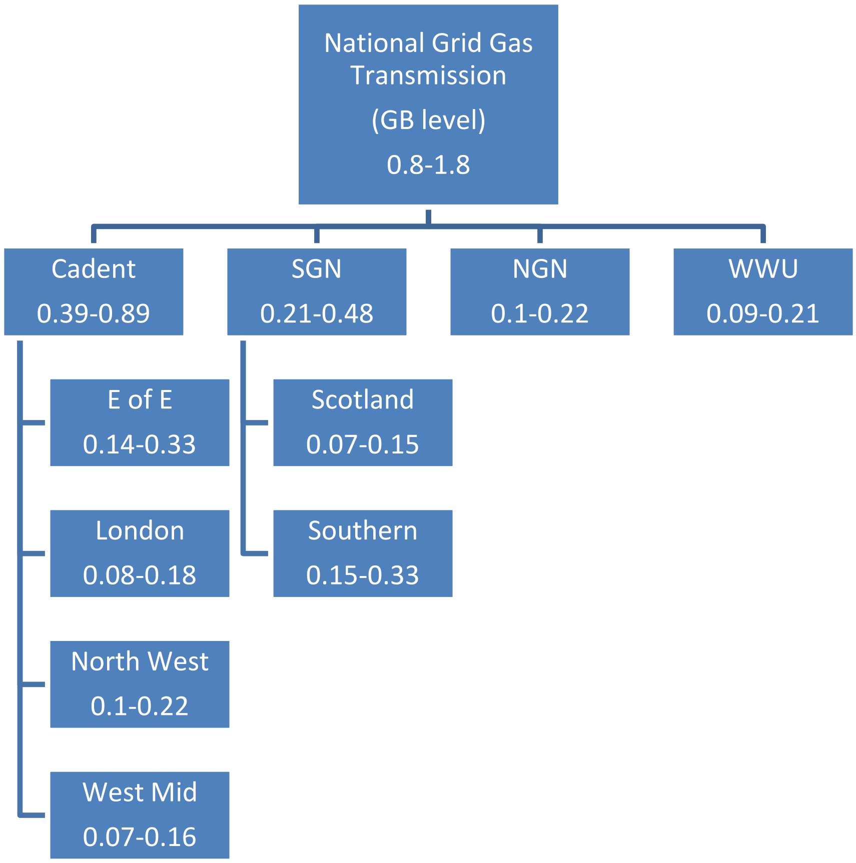
Regional allocation method
The GB view taken from FES 2018 and allocated by the percentage of customers served by each GDN with transmission volumes being an aggregation of GDN values (the GB level).

Cost materiality
A high cost materiality was indicated across the networks for this building block. This reflected the potential investment costs for the networks in alleviating constraints that would allow an increase or better control over the supply of low carbon gases. Currently most of the costs associated with the connection of an entry site are borne by the developer and not the network. The networks have engaged with stakeholders to understand where there may be a willingness to include the costs of low carbon gas entry on consumer bills.

Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
2.18 bcm*	1.33 bcm	0.32 bcm	0.78 bcm	0.25 bcm

The majority view was medium: 0.8 to 1.8bcm of low carbon gas by 2030 with the following regional breakdown (all figures in bcm):



9. Norwegian Gas Supply

Overview
Norwegian gas accounts for around 40% of the UK's gas supply. All Norwegian supply coming into the UK connects to the National Transmission System (NTS). No source of this gas currently connects into the distribution network, nor is it expected to in the future. Therefore, this driver is only associated with NGGT.

Uncertainty
There is a fairly high level of certainty on the forecast supply of Norwegian gas. The FES gets updated on a yearly basis and would take account of any changes to the forecast. If there was significant change in supply that required a change to the NTS, this would be primarily dealt with through customer connections/modifications process. In this instance the cost is borne by the customer not the network.

Interdependencies
There are no strong interdependencies with other building elements.

Regional allocation method
As this is only a NGGT driver, there is no need for an allocation across the distribution networks. The NGGT view has been taken from FES 2018.

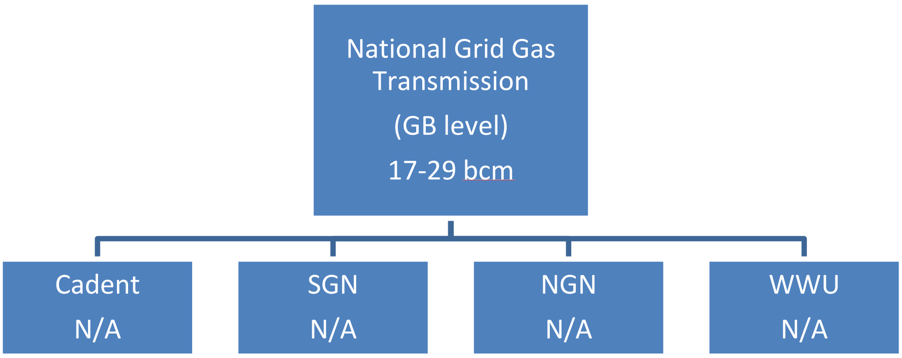
Cost materiality
For RIIO2 this has a relatively low cost materiality for NGGT. There is no forecast of the Norwegian supply significantly changing during RIIO2 and up to 2030. No new major investment or decommissioning of assets is anticipated, with the current infrastructure on the transmission network able to meet customer requirements. If there were any new connections needed, then costs associated with the entry site would be borne by the developer and not the network.

Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
17 bcm*	25 bcm	25 bcm	29 bcm	35 bcm

*bcm – billion cubic meters

The majority view was 'medium': 17-29 bcm of Norwegian gas supply by 2030.



Flexibility

10. Electricity Storage

Overview
Energy storage is an area that is rapidly evolving in GB. Traditional electricity storage was limited to pumped storage, involving the transfer of water between two locations at different elevations. However, recently some network companies are witnessing a large influx of connection applications for battery storage connections. Whilst this is the case, the technology is not yet mature, so the likely level of future connections remains uncertain.

Uncertainty
The future of electricity storage via new technology is largely dependent upon a combination of technology developments and available revenue streams.

Early large scale (transmission and distribution connected) projects have mainly focussed on the provision of Enhanced Frequency Response services to the ESO, due to their ability to adjust output rapidly. Other potential revenue streams could be obtained through capacity market payments, wider balancing services, and within day market arbitrage (also known as "demand shifting"). However, the level of income available would depend on how the cost of the technology evolves.

The financial investment models driving energy storage projects continue to change as potential revenue streams develop. This results in an unclear path as to where energy storage is likely to be connected. Currently the largest revenue streams available require good access to the transmission network, favouring connection directly to the transmission system. However, better whole system co-ordination may remove barriers to participation and allow more of this to be connected at a distribution level, which tends to be more cost effective. Many developers are seeking to connect to the distribution network, with WPD already having a 1.2GW pipeline of accepted energy storage connections across its licence areas.

The introduction of time of use tariffs could result in an uptake in the level of smaller scale battery projects, potentially down to a domestic scale, but this could be limited if a large upfront cost is involved.

Whilst, future pumped storage is limited due to available resources, a number of developers are pursuing potential future projects. These are most likely to be transmission connected.

Interdependencies
Energy storage, could be a disrupter to the future energy market, with potential to displace traditional peaking plant. Whilst this is the case, the overall volume of energy required from generation may increase as a result of storage not being 100% efficient, so may actually increase more non-peaking generation.

Regional allocation method
At distribution level, capacity has been allocated by the proportion of customers in each DNO area. For transmission, allocations have been made based on identified projects for pumped storage, and market share for batteries.

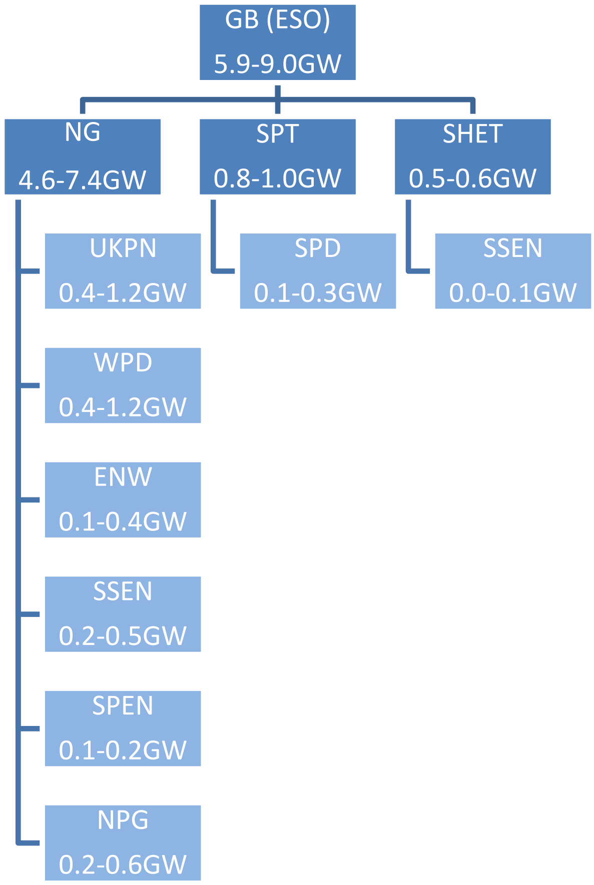
Cost materiality
A medium cost materiality was indicated across the networks for this building block. In the majority of cases, costs associated with this technology would be limited to local investment. Depending on location, and level of penetration, it could act as a means of reducing future reinforcement needs, depending on the future market model.

Position today and by 2030 from FES 2018

Sector	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
Transmission	4.6GW	4.8GW	4.4GW	4.0GW	2.7GW
Distribution	4.4GW	4.1GW	1.5GW	2.9GW	0.2GW
Total	**9.0GW**	**8.9GW**	**5.9GW**	**6.8GW**	**2.9GW**

The majority view was medium to high: network companies' opinions for both transmission and distribution reflected the level of uncertainty, indicating the need for a wide range. For transmission, a large number of battery projects (1.8GW) have contracted to connect by the mid-2020s post-FES18, with customers indicating this could reach a much higher level (beyond

FES18). This is in addition to new pumped storage facilities already accounted within the FES range.



Demand

11. Heat

Overview
In recent years there has been significant discussion around the future of heat and likely uptake of new technologies by homeowners and the resulting impact on gas and power demand. Some specific examples include:

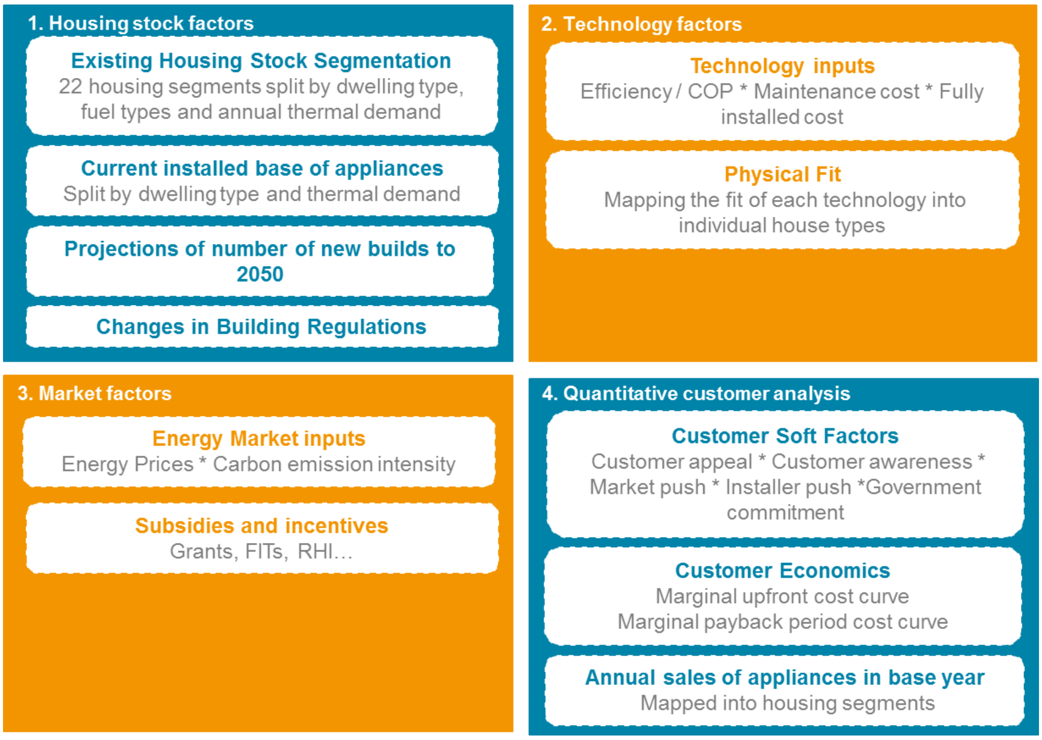
- Electrification; where gas boilers are replace with air source heat pumps which would move demand from the gas sector to the power sector;
- Growth in hybrid (gas boiler and air source heat pump) technology where a proportion of annual demand would move from the gas sector to the power sector but peak demands would remain unchanged;
- Gas grid expansion where oil boilers would be replaced with gas boilers increasing annual and peak demands on the gas networks.

In 2018 the Gas Distribution Networks as part of their long term planning processes undertook a collaborative gas demand forecasting project with Delta EE which considered a number of areas which had the potential to impact network investment requirements. One key area was changes to the baseline of heating technologies: Link to the smarter network portal: http://www.smarternetworks.org/project/nia_wwu_047

The methodology to determine likely pathways of heat technology uptake considered a range of inputs as per the diagram below.

One area that was not considered was use of hydrogen as a change to supply on the basis of the significant other work that is happening in that area.

The Delta EE areas with potential to impact future network investment requirements are set out below:



Uncertainty
The range of drivers in the table above show how many factors need to be considered when forecasting future baselines of heat technology uptake and it is likely that the influences may differ across the regions. In order to provide further clarity in our regional forecasts all networks are engaging with local stakeholders. This may include devolved government heat policy for on and off gas grid communities, local planning requirements for new homes and any local area energy strategies for example social housing.

Interdependencies
There are strong interdependencies between the heat technology uptake parameters.

Cost materiality
At this point in time there is limited data to accurately forecast the likely costs for DNOs if they were required to accommodate a significant migration of heat demand away from gas networks. Preliminary estimates suggest that significant expenditure would be incurred, however as already outlined in this report, the scale and timing of any migration of heat demand to electricity networks is highly uncertain. As such the current view was in the short term this is deemed to be of medium impact, but this will need to be revisited as part of the refresh work undertaken in advance of RIIO-ED2.

Position today and by 2030 from FES 2018 and Delta EE
In the table below we have detailed the 2030 projections from delta, with the baseline data from FES for 2018 and Delta EE for 2018 and show how we have connected different categorisation of heating types.

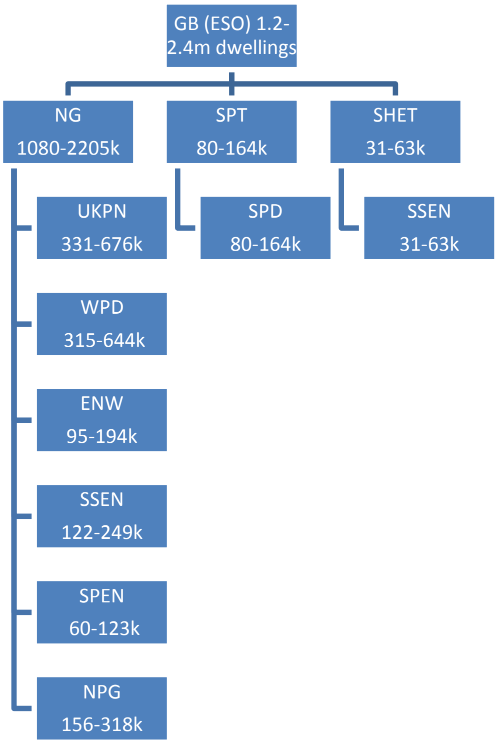
FES term	Delta EE term	FES 2017	Delta 2018	Delta 2030
ASHP	ASHP	29,339	140,476	303,844
BIO-LPG	Biomass	0	42,201	33,772
Electric storage heater	Electric storage heater	2,077,074	2,605,486	2,858,600
District Heat	District heating	450,000	432,082	1,065,045
Gas boiler	Gas boiler high efficiency	21,933,029	18,226,795	24,449,229
Gas boiler	Gas boiler plus solar thermal		2,876	18,267
Gas boiler	Gas boiler standard efficiency		5,389,981	0
Gas heat pump absorption	Gas heat pump absorption	0	104	22,870
GSHP	GSHP Borehole	8,658	20,737	23,963
GSHP	GSHP Trench		15,569	18,467
Hybrid heat pump gas boiler	Hybrid heat pump gas boiler	0	467	155,499
Oil boilers	Hybrid heat pump oil boiler	3,328,873	38	331
Micro-CHPs (inc Fuel Cells)	Micro-CHP engine - gas ICE	1,003	192	0
Micro-CHPs (inc Fuel Cells)	Micro-CHP engine - gas stirling		3,563	18,439
Oil boilers	Oil boiler	3,328,873	1,285,956	1,323,093
Oil boilers	Oil boiler plus solar thermal		0	0
Gas boiler	Gas boiler plus solar PV	21,933,029	14,084	41,938
	Total	**27,827,976**	**28,180,607**	**30,333,356**

The following table shows how the Delta EE projections differ to the FES scenarios, with the closest match being highlighted in yellow:

FES categories	Consumer Evolution	Steady Progression	Two Degrees	Community Renewables	Delta EE
ASHP	960,216	253,581	2,115,330	3,071,909	303,844
Electric storage heater	2,448,602	2,461,322	2,313,711	2,310,363	2,858,600
Gas boiler	22,642,856	22,934,319	20,550,149	20,115,107	24,509,434
Gas heat pump absorption	23,744	15,857	89,642	50,696	22,870
GSHP	180,003	137,672	164,898	195,783	42,430
Hybrid heat pump gas boiler	159,980	75,331	348,062	453,514	155,499
Micro-CHPs (inc Fuel Cells)	24,025	18,865	40,022	33,138	18,439
Oil boilers	2,730,015	3,138,997	2,467,013	2,366,178	1,323,424
Hydrogen	-	-	60,000	-	0
District Heat	583,498	716,996	1,517,982	983,991	1,065,045
Bio-LPG	-	-	86,130	172,259	33,772

Regional allocation method

Air Source Heat Pumps (ASHPs) and district heating are expected to be the two technologies with the most material impact on the electricity network. The electricity sector view for ASHPs and district heating schemes has been taken from FES 2018 and allocated by the percentage of customers served by each DNO with transmission volumes being an aggregation of DNO values. For gas networks this information has fed into peak demand projections provided elsewhere in this document.



12. Low Carbon Transport

Overview
One of the key pillars for the decarbonisation of the UK economy is through reducing emissions associated with transport. Since 2018 this sector has been the highest emitter of CO2, as electricity sector has decarbonised rapidly. The Government has an ambition to ban the sale of new petrol and diesel cars by 2040, indeed some of the nations and regions have more ambitious approaches – notably the Scottish Government's ambition to remove the need for new petrol and diesel vehicles by 2032. The 2017 FES did not explicitly consider the Government's Road to Zero targets, whilst many DNOs have subsequently ramped up their projections in the short to medium term in light of policy developments.

Uncertainty
While there is uncertainty around the precise nature of how transport will be decarbonised, we are more certain that domestic and light vehicles are likely to follow the electrification route, given policy interventions, investment in charging infrastructure and public statements by vehicle manufacturers. For heavier good vehicles, there is move movement towards gas and hydrogen vehicles, but we feel this area is less certain given Government policy and incentives, vehicle manufacturers' product development and business customer behaviour. At the same time this area is starting to see an increase in interest. For example more cities are converting bus fleets to hydrogen power.

Interdependencies
There is a natural interdependency between electric and gas and hydrogen vehicles, as the total transport requirement being "capped" at the total number of vehicles required. However, we do not believe this is material out to 2030 given the different subsectors we see adopting electric and gas/hydrogen vehicles. Longer term, this will become a consideration as almost all vehicles will need be low carbon to meet 2050 targets.

Regional allocation methods
For EVs the GB view taken from FES 2018 and the regional allocation based on the percentage of customers served by each DNO with TO volumes being an aggregation of DNO values.

For gas/hydrogen vehicles the GB view taken from FES 2018 and the regional allocation based on the percentage of customers served by each DNO with TO volumes being an aggregation of DNO values. Note this allocation method may not fully represent gas/hydrogen vehicle uptake, which is further influenced by commercial fleets and natural geography.

Cost materially
High for EVs for electricity distribution. The future location and type of charging behaviour is currently unclear, with the potential for at home charging requiring significant upgrades of low voltage networks and potentially more reinforcement at higher voltages to accommodate a greater penetration of ultra-fast charging locations.

Low to Medium impact for EVs for transmission owners. The level of impact on at a transmission level will largely relates to desire to build a network of rapid charging facilities. Providing a network of fast and rapid charging points at strategic locations across the country could form part of a wider government policy to remove range anxiety, a potential key step to enable a widespread transition to EVs. Should such a government policy be implemented, then the impact on transmission could shift to high depending on the number of new transmission connections required. However, the changes in underlying peak demand, as a result of increasing EVs in RIIO-T2 alone is not expected to drive major system reinforcements at transmission.

Low for gas/hydrogen vehicles. Physical connections to either the **gas distribution** or **gas transmission** networks are funded by developer customer connections process. While the additional gas demand could create potential demand for reinforcement and compression, these are funded by developer customer connections.

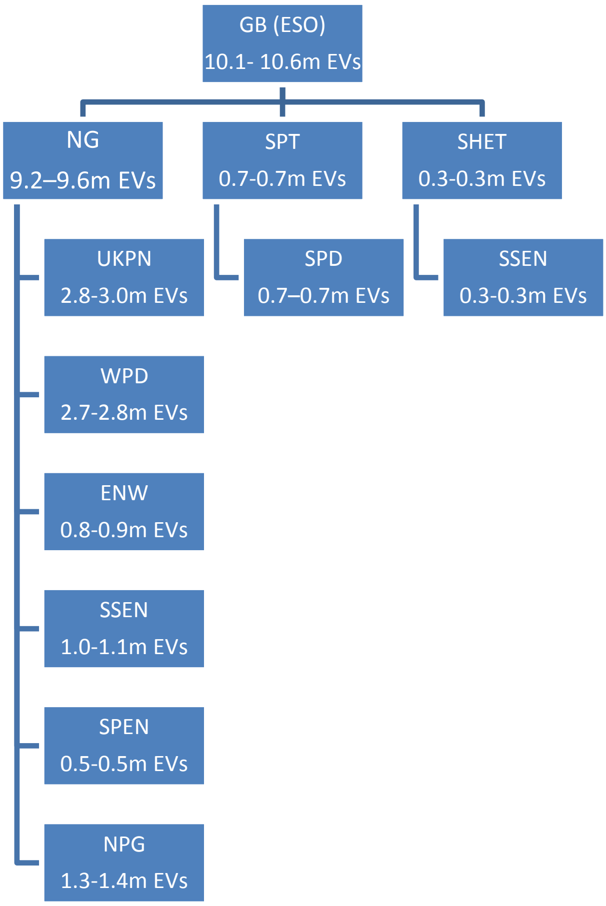
Low for EVs for electricity system operation. While new markets are opened up to increased competition, including EVs, the costs of these are outweighed by the benefits to consumer form this competition, leading to low bills that otherwise. While electricity demand from EVs will increase, including at peak, this will be offset by decreasing demand elsewhere out to 2030.

EVs

Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
10.63 million	10.10 million	2.74 million	2.68 million	0.06 million

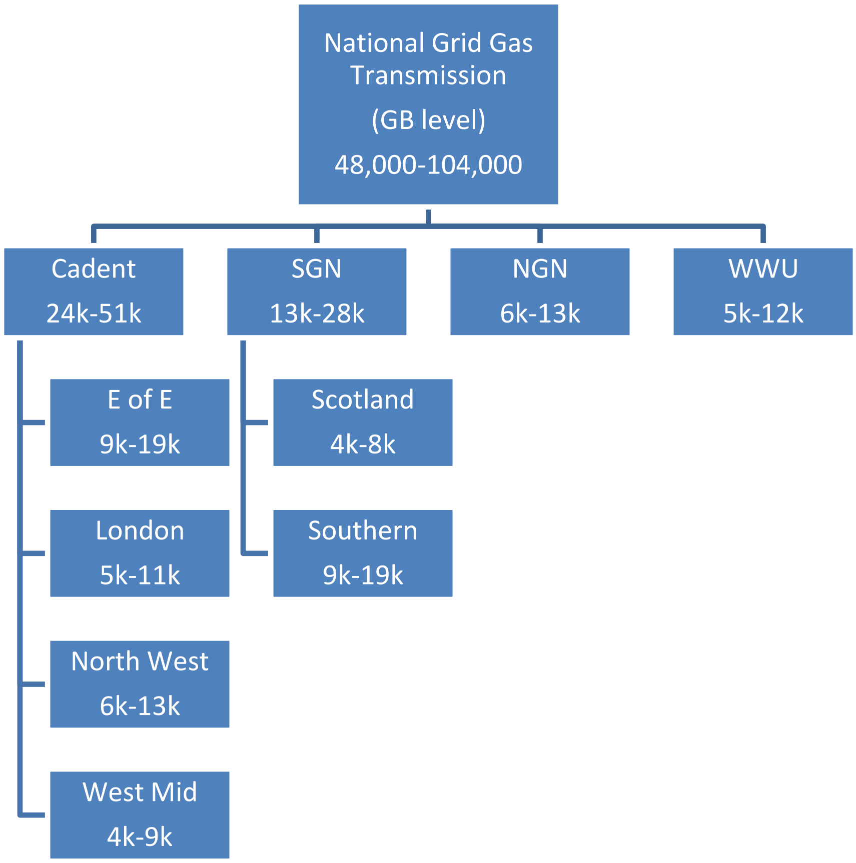
The majority view was high: 10.1 to 10.6 million vehicles by 2030 with the following regional breakdown (note all vehicles assumed to connect and DNO level, transmission view is for impact purposes no connections):



Gas/Hydrogen Vehicles
Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
104,000	97,000	49,000	48,000	~ 1,000

The majority view was medium (large range): 48,000 to 104,000 vehicles by 2030 with the following regional breakdown (note all vehicles assumed to connect at GDN level, transmission view is for impact purposes, with a current assumption of no connections). However, if there were to be connections to the transmission system, this would be managed through the connection process:



13. Peak Gas and Electricity Demand

Overview
Peak demand is the primary energy system design and operating parameter, which plays a significant role in driving the assets installed, maintained, and decommissioned, and the required level of secure and reliable energy supply. In more recent years the growth of DG has resulted in summer minimum becoming a more prominent planning factor.

The electricity system peak has become increasingly influenced by embedded small scale electricity production, which can operate during peak conditions to offset the peak demand particularly when they are encouraged to generate through commercial mechanisms such as triad avoidance.

Although transmission networks see the diversified effects of DG, the distribution networks need to consider the reality that non-diversified generation can be switched off or not be co-located with peak demand. This highlights the significance of distribution network planners being able to identify the future trends of underlying peak demand at a regional level that is independent from any generation trends.

The electricity demand takes into account the number of appliances, the number of smart appliances and the increase in appliance efficiency. The gas demand includes changes in energy efficiency and new heating take up, offset in part by demand growth.

Uncertainty
Volume is dependent on backup for intermittent renewables, heat policy, CNG transport, boiler/home efficiency and deployment of smart appliances.

Gas demand will be affected by government heat policy, and the market's and consumer's response to this policy. High levels of energy efficiency improvements to the existing housing stock would impact gas demand. The roll out and use of electric and gas vehicles could also result in higher gas demand to provide the secure power supplies.

Electricity demand will be closely related to the DSO transition with the emergent markets influencing when demand will be consumed and its consequential impact on peak, but the volume of this is still not well understood at this time. Electricity demand is correlated not only with future trends in electrification of transport and heating and the associated profiles peaking at the same time with peak demand, but also with regional developments driven by prosperity and incentivised by low carbon policies. The DSO transition can provide a more efficient balancing of network capacity to facilitate peak demand and generation growth at the most cost efficient and risk averse manner.

Interdependencies
There is a dependency between the levels of back up gas generation required by the electricity sector to securely balance supply and demand, and the levels of intermittent renewables, and the take up and use of EVs.

Regional allocation method
The allocation method is based on peak demand from the RIIO-ED1 2017/18 annual report for the distribution networks, which have then been amalgamated at the TO and ESO levels. Individual networks will produce their own bespoke bottom up forecasts to support their Business Plans, which may deviate from the allocation approach used in this exercise.

Cost materiality
A low cost materiality was indicated across the gas networks for the peak gas demand

building block, as load or capacity driven investment is a very small component of annual expenditure, and connecting customers generally fund the bulk of the costs directly. However, for gas transmission in the last few days of March 2019, there has been an acceptance of a capacity increase for Milford Haven LNG terminal, which requires a feasibility of what investment may be needed to support this.

For electricity networks the cost materiality is more significant, and the peak demand typically drives investment which is attributed to general load growth. Although national peak demand may not grow significantly, the make-up of the demand may change. A lot of the significant growth is covered in the other key drivers. The picture is mixed across transmission and distribution, with a more significant cost materiality on the distribution networks and a low to medium materiality for transmission.

Position today and by 2030 from FES 2018 are shown in the table below. Due to the different characteristics of the electricity and gas networks, with short term system balancing on the power grid, electricity peak demand is measured in units of power (GW). Gas is measured in terms of peak day energy demand (GWh), although with increasing levels of fast start-up gas generation, shorter term gas demand is becoming a cost driver, and this is measured in GW.

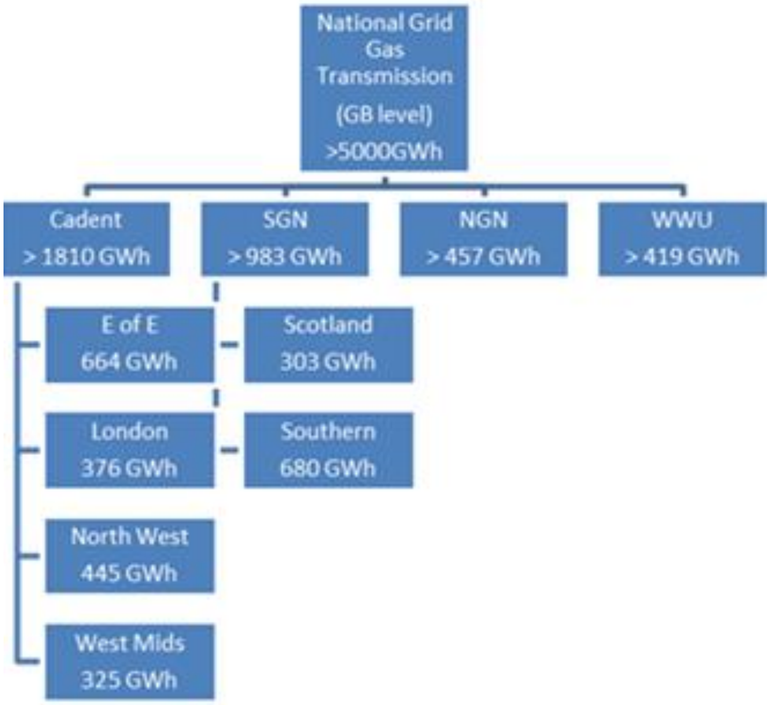
	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
Electricity Peak	62GW	63.8GW	62.3GW	63.7GW	59.4GW
Gas 1 in 20 Peak Day	3993GWh	4057GWh	5092GWh	5034GWh	5500GWh
Gas Peak Hour	Not in FES	Not in FES	Not in FES	Not in FES	214GW

The majority view was medium/high for electricity peak: 62.3-63.8GW by 2030. Assumptions of peak gas demand are not currently Building Blocks used in the FES 2018 assessments, so there is no majority view from this initial view. The gas network consensus view is **High** for 1 in 20 Peak Day demand, at 5000GWh by 2030, and Medium for Gas Peak Hour at 220-230GW.

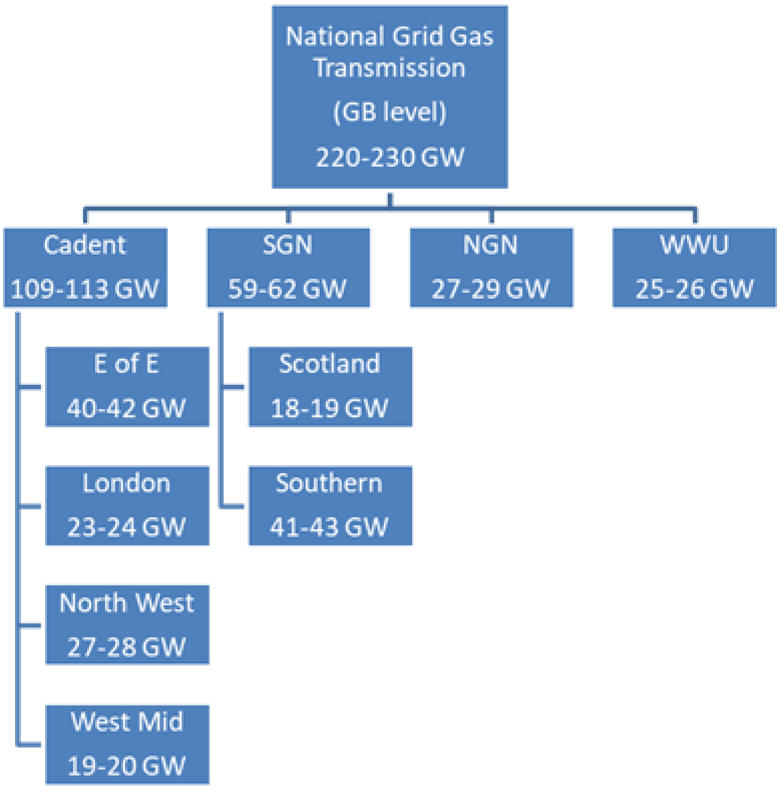
The peak demand figures here represent the off-take from the transmission system to the distribution network. It does not take into account any embedded generation, demand side response or flexibility which may operate within the distribution network and for which the distribution network may have to be secured for. Although transmission networks see the diversified effects of embedded/distributed generation suppressing demand, the distribution networks need to be designed by acknowledging the fact that non-diversified generation can a) be switched off or b) not be co-located with peak demand. This in practice means that distribution network operation needs to balance network capacity to supply peak demand at a regional level.

These figures are broken down regionally as follows.

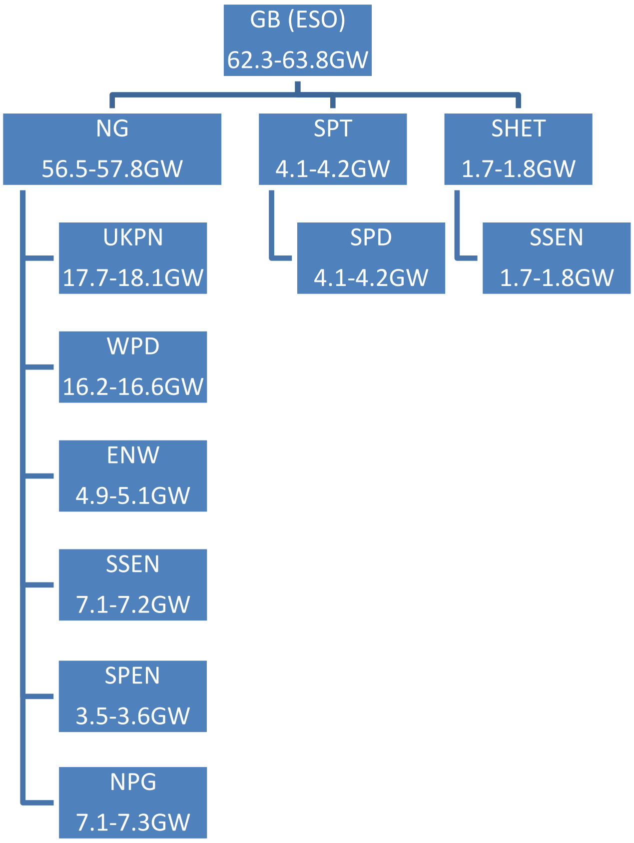
Gas 1 in 20 Peak Day



Gas Peak Hour



Electricity Peak Demand



14. Smart appliances and demand side response

Overview

As the energy system become more digitalised the number of smart appliances is set to increase, allowing consumers to take back control of how and when they use energy. These combined with the roll out of smart meters and dynamic pricing from supplies will incentivise consumers to change their behaviours and be rewarded to support the development of the electricity networks and system operation for example through peak time avoidance.

Uncertainty

The rapid uptake of all forms of smart technology and the proliferation of dynamic pricing has increased the scope of what may be possible here, although the roll out of smart meters has proved challenging to date. It is still unclear when there will be the roll-out of sufficient volumes of smart meters that provide all the potential benefits of smart metering. It is also currently uncertain how suppliers will incentivise customers and how customers will respond to price signals and incentives. In places it has been observed that whilst some industrial and commercial customers are able to shift net demand and respond to price signals, the majority of this is realised by behind the meter generation rather than true demand reduction or shifting.

Interdependencies

While a component of overall peak demand, there are no strong interdependencies with other elements.

Regional allocation methods

The GB view taken from FES 2018 and the regional allocation based on the percentage of customers served by each DNO with TO volumes being an aggregation of DNO values.

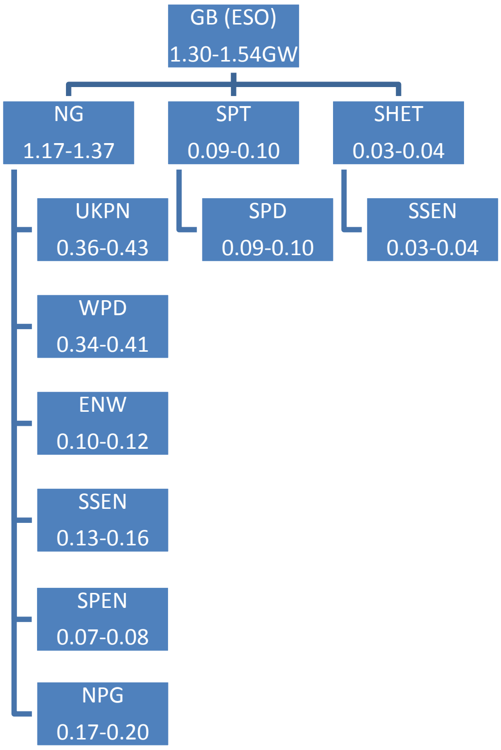
Cost materially
There is a significant cost materially through the impact of smaller scale flexibility being used. Through the DSO transition there will be more ways to incorporate flexibility. This will need to be supported through investment in IT systems, Operational Technology infrastructure and communication links. These are likely to require significant engagement and market stimulation to reap the long term rewards of smaller scale demand side response.

Low for electricity system operation. While new markets are opened up to increased competition, including aggregation of smart technologies, the costs of these are outweighed by the benefits to consumer form this competition and services offered, in particular offsetting any peak demand seen out to 2030.

Smart Appliances – reduction at peak
Position today and by 2030 from FES 2018

Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
1.54 GW reduction	1.30 GW reduction	0.35 GW reduction	0.52 GW reduction	N/A

The majority view was high: 1.30 to 1.54 GW reduction by 2030 with the following regional breakdown:



Industrial and Commercial demand side response

Overview
Industrial and Commercial demand side response is where non-domestic customers connected to the electricity system are able to be flexible about their power usage. In reality this is achieved through machinery, equipment, or heating activity being reduced or curtailed during peak periods. Nationally there is at least 1 GW of Industrial and Commercial demand side response, with figures generated post the 2018 FES indicating this may now be around 2 GW. This is an area that will be revisited in the next iteration of this work.

Uncertainty
The cost of energy drives uncertainty in terms of variable in terms of the increasing availability of Industrial and Commercial demand side response. It can be seen that during periods of higher energy costs that participation in triad avoidance (an analogous activity) increases. Electricity demand (and therefore demand side response) will be closely related to the DSO transition with the emergent markets influencing when demand will be consumed and its consequential impact on peak, but the volume of this is still not well understood at this time.

Interdependencies
There is an interaction with energy storage and other forms of embedded generation; this achieves the same end in reducing peak demand (behind the meter storage and generation is excluded from this exercise).

There is an interaction with Electricity Transmission flexibility as the utilisation of either would supress the general need.

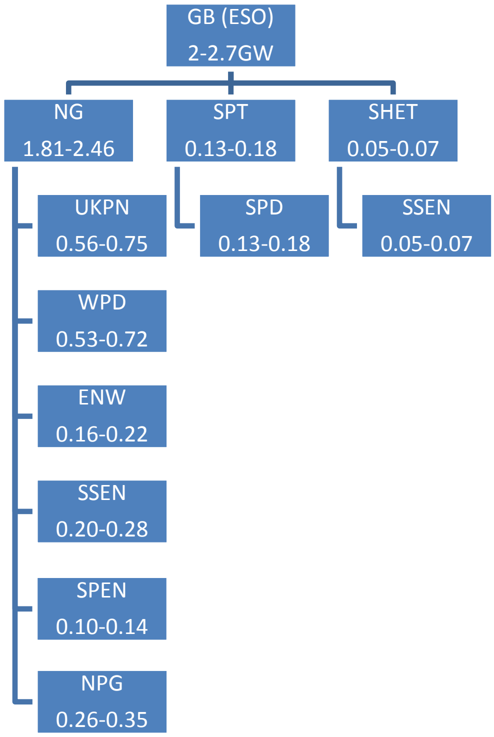
Regional allocation method
The allocation method is based on number of customers of this category, and the prevalence and forecast changes to Industrial and Commercial customers and the proportion that will have demand side response. Individual networks will produce their own bespoke forecasts to support their Business Plans, which may deviate from the allocation approach used in this exercise.

Cost materiality
Position today and by 2030 from FES 2018 are shown in the table below. The FES assumes that Industrial and commercial demand side response to be 1.4-2.5GW by 2030.

	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	2017 View
Industrial and Commercial Demand Side response	2.5GW	2.1GW	1.4GW	1.5GW	1.0 GW

There was no majority view. The highest proportion was low (>35% Industrial and Commercial Business participation) but that there were a wide range of views: 2-2.7GW by 2030.

Electricity Peak Demand



9. Appendix

Following the meetings with the CG, a number of queries were raised in relation to different aspects of this analysis.

Q. Identify and explain the key downward cost drivers as well as upward ones

A. Across the building blocks, some will have the potential to be downward cost driver as well as upwards. Peak electricity demand is expected to reduce in the RIIO-2 period, which is a result of new demand side response measures, energy efficiency and other measures. In some localities, this will offset increased demand from the electrification of transport and demand growth in other areas. There will be additional cost associated with the connection of energy storage but in the long term it is anticipated that this will also offer potential downward cost as the storage can be used to manage loading and avoid reinforcement.

Different forms of electricity generation will have a mixed impact. Decentralised energy such as solar may in some instances address demand locally which may partially negate some reinforcement, however, peak demand (which is one of the key drivers for expenditure) occurs in a winter evening, resulting in these technologies having a very limited impact. Across the electricity network, the roll out of new generation has created a number of new issues such as reinforcement to allow the power to be transferred across the country to areas where demand is at that time, or operability issues such as high voltage.

Q. Provide background details on specific initiatives or assumptions that are included

A. This has been included as part of commentary in respective sections.

Q. Explain what assumptions you are making on subsidies, including timelines.

A. Tis has been included as part of commentary in respective sections and in the introduction.

Q. Demonstrate the scenarios are consistent and not a collection of assumptions.

A. This has been considered through the ESO independent review of this work and that the assumptions made are reasonably coherent and consistent.

Q. Specific case studies demonstrating key points would be helpful e.g. trade-offs between electricity and gas for heat pump assumptions.

A. Additional narrative has been included in the sections on heat and transport on some of the interactions and trade-offs that will be required.

Q. Ensuring the ESO reviews the robustness of the ENA scenarios as well as comparison to the FES. We would be also interested in seeing this report.

A. A copy of the ESO report is attached for reference.

Q. What contribution to overall demand will be impacted by energy efficient lighting?

A. Based on the FES 2018, total energy consumptions from lighting was reported as being 11.1TWh in 2017 which accounted for approximately 3.5% of total annual electricity consumption. Across the FES scenarios, lighting consumption is forecast to be between 6.2-11.1TWh p.a. (up to 45% reduction from 2017). The saving in a high scenario equates to approximately 1.5% reduction in total annual energy consumption from 2017. This saving needs to be balanced against other changes, in particular the electrification of transport and other areas which have a far greater impact. This specific area has not been included as one of the material building blocks that will have a major impact on expenditure in the RIIO-2 period due to the low level impact overall.