FUTURE REGULATION OF THE UK GAS GRID

Impacts and institutional implications of UK gas grid future scenarios – a report for the CCC

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EXECUTIVE SUMMARY

The CCC has established a variety of viable scenarios in which UK decarbonisation targets can be met. Each has consequences for the way in which the UK's gas network infrastructure is utilised. This report considers the implications of decarbonisation for the future regulation of the gas grid.

The CCC's 5th Carbon Budget envisaged different scenarios that would enable the UK to meet its emissions targets for 2050. These scenarios represent holistic analyses, based on internally consistent combinations of different technologies, which could deliver carbon reductions across different sectors of the economy.

The CCC's scenarios incorporate projections of the demand for natural gas to 2050. The scenarios imply that the volume of throughput on the gas networks[1], and the nature and location of network usage, is likely to change significantly to meet emissions targets. They are also characterised by significant uncertainty.

- Under some decarbonisation scenarios, gas networks could be re-purposed to supply hydrogen instead of natural gas, meaning there would be ongoing need for network infrastructure.
- In other scenarios, gas demand in buildings is largely replaced by electric alternatives, meaning portions of the low pressure gas distribution networks could be decommissioned.
- Patchwork scenarios are also possible, in which there is a mixture of these outcomes across the country.

In this project, the CCC wished to assess the potential implications for gas networks under these different demand scenarios; and evaluate the associated challenges for Government and regulatory policy. The challenge for BEIS and Ofgem is how to regulate in a way that keeps options open while uncertainty persists about the best solution for the UK; and at the same time how best to make policy and regulatory decisions which would serve to reduce this uncertainty. Both Government and Ofgem have policy and regulatory levers that they can use – and we identify and evaluate such levers in this report.

The purpose of this report is not to compare across scenarios with a view to recommending a least-cost pathway or identifying the "right" solution for the UK. Such an assessment would depend on a large number of factors, including (but not limited to) the level of emissions abatement that can be achieved in other sectors of the economy; the success of rolling out heat pumps, heat networks and energy efficiency; the development of Carbon Capture and Storage (CCS) as a route to low-cost hydrogen; the viability of hydrogen itself; the need to ensure security of supply and replace the daily and seasonal energy storage capacity

[1] The gas networks comprise of the National Transmission System (NTS) which transports large volumes of gas at high pressure across the UK; and the eight Gas Distribution Network (GDN) licence areas which transport gas at lower pressures from the NTS to customers. The eight GDNs licences are currently owned by four separate corporate groups.

that would be lost if there were significant decommissioning of the gas networks; and, crucially, customer acceptance and willingness to switch to new technologies in any of these scenarios[2].

Instead, our purpose is to evaluate whether aspects of the current regulatory and institutional framework for regulating the gas networks would need to be reformed to meet each scenario[3]. The report therefore has three main aims.

- To review the current regulatory and institutional framework relating to the gas network, and assess the extent to which it is capable of both managing, and adapting to different decarbonisation scenarios.
- To determine the key issues going in to the next gas network price control review in order to prepare for low-carbon transitions, along with the immediate implications for Government.
- To establish what is required over the next 5-10 years for Government to be in a position to set out a strategy for the future of the gas grid to 2050, including the role of hydrogen for heat.

This work is undertaken at an important time for gas network regulation. Ofgem's next price control reviews are expected to be launched in late 2018, and finalised by late 2020. These reviews will determine the network's cost allowances, revenues, and investment incentives for the period 2021 – 2028. Since network assets are long-lived, investment and policy in the 2020s will impact on the UK's pathways to meeting its long-run targets.

Description of the scenarios

The CCC has asked us to assess four demand scenarios.

- **Scenario 1 (Central)** is consistent with the CCC's central scenario in the 5th Carbon Budget. Gas use declines to around 50% of its present level by 2050, but the gas grid is largely still required to service the remaining demand. For the purposes of our analysis, we assume this includes areas where pipes are kept in place to meet peaks in demand arising from the use of hybrid heat pumps[4]. This scenario also assumes that Carbon Capture and Storage (CCS) is operational, gas demand for power generation continues, and most of the decline in aggregate demand arises in the buildings sector.
- In **Scenario 2 (Low Gas)**, gas use declines more rapidly, falling by over 80% by 2050 relative to today. This is based on the premise that there is no CCS technology available. We assume that demand reductions are facilitated by co-ordinated and planned switching to alternative heating technologies such

[2] A recent report by a set of industry experts at Imperial College Centre for Energy Policy and Technology (ICEPT) undertook a more detailed comparison of system costs of alternative solutions. See Managing Heat System Decarbonisation, Comparing the impacts and costs of transitions in heat infrastructure, April 2016. http://provpol.com/wp-content/uploads/2016/05/Heat-infrastructure-paper.pdf

[3] This work does not consider whether there are any regulatory or institutional changes resulting from the recent UK referendum decision to leave the EU, or the extent to which this result could affect the achievement of decarbonisation objectives.

[4] The CCC's 5CB Central scenario does not designate a portion of heat pump uptake as hybrid systems, but the CCC notes that hybrids could be part of the future mix.

as low carbon district heat networks and heat pumps. This means that large portions (potentially up to 80%) of the gas grid can be decommissioned[5].

- In **Scenario 3 (National Hydrogen)**, the potential for hydrogen to replace natural gas as a fuel for domestic heating and consumption is realised. A national switchover from natural gas to hydrogen is undertaken with the existing grid being re-purposed to carry hydrogen and continuing to service a large amount of demand. For hydrogen to result in a reduction of carbon emissions, it must be combined with CCS technology[6].
- In **Scenario 4 (Patchwork Hydrogen)**, the switchover to hydrogen is confined regionally to areas in northern England, where hydrogen infrastructure is most likely to be economic as a result of geological constraints which limit the location of available CCS and hydrogen storage capacity. There is a 'patchwork' switchover, where parts of the distribution grid are converted to carry hydrogen; parts of the grid are decommissioned; and parts service the remaining demand for gas.

For each of these scenarios, we have developed a stylised description of how network operations will evolve. From this, we derived estimates of the investment and operating cost requirements for the networks to 2050.

Our analysis is drawn largely from cost allowances determined by Ofgem at the most recent RIIO reviews for the gas distribution and transmission networks. These costs are projected forward assuming some ongoing productivity/efficiency improvements where relevant; and based on our high-level expectation for how the drivers of network costs will evolve in each scenario.

For the purposes of assessing the costs of hydrogen infrastructure, we have primarily utilised the latest available information arising from the Leeds H21 project[7], which has undertaken detailed technical research into the challenges associated with converting to hydrogen[8]. We have also drawn on industry and technical expertise provided by Aqua Consultants; and on information provided by a variety of stakeholders whose contributions have been extremely helpful in informing the analysis and conclusions of this report.

Tariff implications of each scenario under the existing model of network regulation

Based on the demand and cost forecasts described above, we calculated a set of projections of network tariffs to 2050 in each scenario. To do this, we built a

5 For our scenario analysis, we assume 80% of distribution network is decommissioned by 2050. We understand there may be alternative uses for the NTS in future (e.g. transporting US LNG through Europe via interconnector). We therefore assume that 50% of the NTS is decommissioned, but that network costs associated with alternative NTS uses are not socialised across UK domestic gas customers.

6 This is based on assuming that Steam Methane Reformation (SMR) is the primary source of hydrogen production. In future, it is possible that other forms of hydrogen production – notably through electrolysis – could become more cost-effective, which would mean CCS technology would not be required.

7 The H21 project was led by Northern Gas Networks:http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/

8 In addition, where relevant we have cross-checked data against a recent report by KPMG commissioned by the Energy Networks Association Gas Futures Group, The UK Gas Networks Role in a 2050 Whole Energy System: http://www.energynetworks.org/gas/futures/the-uk-gas-networks-role-in-a-2050-whole-energy-system.html

model which converts our network cost projections for each scenario into annual revenue requirements for each GDN and the NTS. Our approach seeks to replicate the key features of Ofgem's current economic model for determining allowed revenues for the networks at its periodic price control reviews, known as the Regulated Asset Base (RAB) model[9].

The summary outputs are shown for the gas distribution and transmission networks respectively in Exhibit 1 and Exhibit 2 below.

- ***Allowed revenue*** shows the change in network revenues by 2050, relative to 2017. This is the total amount of revenue Ofgem would allow the companies to earn, assuming Ofgem continues to employ the RAB model it uses today.
- ***Volumes*** shows the change in total gas throughput (methane and/or hydrogen) on the networks under each scenario.
- ***Implied network tariffs*** shows an approximation of the impact on network tariffs (and therefore remaining network customers) by dividing the annual revenues by total gas demand[10].
- ***Outstanding RAB*** shows the change in the value of the RAB by 2050, relative to 2017. The RAB is important to investors in networks, since (broadly speaking) it represents the outstanding value of investment which has yet to be recovered from customers. The total RAB therefore gives an indication of the absolute value assets which remains exposed to the risk of stranding.
- ***RAB per TWh*** is calculated by dividing the RAB by volumes. This gives a high-level indication of whether there is likely to be increased stranding risk – if RAB/TWh increases, this implies that a greater quantum of RAB must be recovered from a lower customer base, indicating that the recovery of that investment may be more at risk.

[9] At a high level, Ofgem currently sets annual revenue allowances to cover depreciation of the RAB and a return on the RAB, as well as an allowance to cover annual operating costs. We have made a number of simplifying assumptions in developing this model – for example, holding the allowed cost of capital constant to 2050; and extrapolating network tax allowances based on their current levels. Our model produces revenues which approximately match Ofgem's revenue allowances in the current price control periods.

[10] In reality, different network tariffs are set for different customers and a large component of network tariffs is capacity-based. However, our aggregate tariff calculation allows us to draw broad conclusions on the impact on tariffs in each scenario, and is consistent with the way the CCC has presented network tariffs elsewhere.

Exhibit 1. Summary of modelling results – aggregated across distribution networks

	Scenario 1 (Central)	Scenario 2 (Low Gas)	Scenario 3 (National Hydrogen)	Scenario 4 (Patchwork Hydrogen)
Allowed revenue (£ m)				
Start (=2017)	3,426	3,426	3,426	3,426
End (=2050)	2,381	1,994	2,608	2,434
% Change	-30%	-42%	-24%	-29%
Volumes (TWh)				
Start	522	524	523	523
End	182	92	646	340
% Change	-65%	-83%	24%	-35%
Implied network tariffs (p/KWh)				
Start	0.7	0.7	0.7	0.7
End	1.3	2.2	0.4	0.7
% Change	100%	233%	-38%	9%
Outstanding RAB (£ million)				
Start	17,609	17,609	17,609	17,609
End	7,860	6,444	8,900	8,108
% Change	-55%	-63%	-49%	-54%
RAB per TWh (£ million)				
Start	34	34	34	34
End	43	70	14	24
% Change	28%	109%	-59%	-29%

Source: Frontier Economics. For the gas distribution networks (GDNs), the figure shown is the aggregate change across all eight licensees.

Exhibit 2. Summary of modelling results – transmission network

	Scenario 1 (Central)	Scenario 2 (Low Gas)	Scenario 3 (National Hydrogen)	Scenario 4 (Patchwork Hydrogen)
Allowed revenue (£ m)				
Start (=2017)	616	616	616	616
End (=2050)	579	496	747	579
% Change	-6%	-19%	21%	-6%
Volumes (TWh)				
Start	711	712	711	711
End	332	123	781	486
% Change	-53%	-83%	10%	-32%
Implied network tariffs (p/KWh)				
Start	0.1	0.1	0.1	0.1
End	0.2	0.4	0.1	0.1
% Change	101%	365%	11%	37%
Outstanding RAB (£ million)				
Start	5,134	5,134	5,134	5,134
End	3,901	3,255	5,800	3,901
% Change	-24%	-37%	13%	-24%
RAB per TWh (£ million)				
Start	7	7	7	7
End	12	26	7	8
% Change	62%	266%	3%	11%

Source: Frontier Economics.

The modelling work allows us to draw some broad conclusions around the likely impact of each scenario on customers and investors, if Ofgem's economic model remains unchanged.

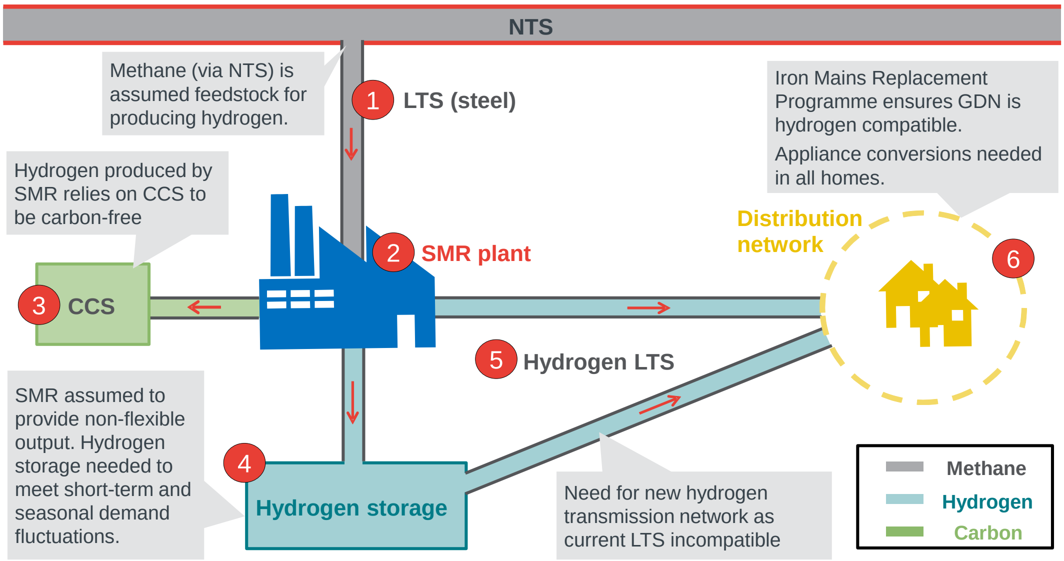
- In **Scenario 1 (Central),** the implied network tariff increases appear manageable within the current regulatory model. Ongoing gas volumes (which are sustained largely as a result of CCS) are likely to reduce stranding risk.
- In **Scenario 2 (Low Gas)**, the challenges for regulation are more significant, since network tariffs would increase more materially. Given the absence of CCS in this scenario, the recovery of outstanding investment would be spread over a dwindling customer base, suggesting higher stranding risk.
- In **Scenario 3 (National Hydrogen)** the re-purposing of existing network infrastructure results in falling network tariffs from 2030 onwards (assuming that only the costs of the new Hydrogen Transmission System pipelines are included in the regulated tariffs).
- **Scenario 4 (Patchwork Hydrogen)** illustrates that while patchwork scenarios may be optimal from a system costs perspective, they could imply material regional price variations for customers. The emergence of

differentials in the costs faced by customers with different low carbon heating systems is likely to raise questions of fairness[11], as well as impact on customer acceptance of any mandated change to their heating solution.

These conclusions are based purely on the network charges resulting from each scenario. Network charges are just one component of final customer bills (currently network charges constitute around 20% of average domestic customer bills). Our results, therefore, do not allow conclusions to be drawn about the whole-system cost differentials across scenarios; or to identify which scenario would be "cheapest" for customers - although they may be used as an input to such an assessment in future.

To illustrate this, Exhibit 3 shows the full set of infrastructure components which would be required under the hydrogen scenarios.

Exhibit 3. Hydrogen infrastructure schematic



Source: Frontier Economics

A hydrogen switchover would involve:

- transportation of methane through the existing National Transmission System (NTS) and Local Transmission System (LTS) (item 1 in Exhibit 3);
- Steam Methane Reformation (SMR) plant to produce hydrogen (item 2)[12];
- CCS infrastructure (item 3);
- storage facilities for hydrogen (item 4)
- a new Hydrogen Transmission System (HTS) (item 5); and
- conversion of appliances in homes to be compatible with hydrogen (item 6).

Our tariff results in Scenarios 3 and 4 are calculated on the basis of including **only** the NTS and LTS costs (item 1) and the new HTS pipe network (item 5) in

[11] For example, if the costs of hydrogen infrastructure are socialised across wide groups of customers or taxpayer-funded, while costs of switching to other technologies in non-hydrogen regions are not subsidised, there is a risk that some customers would bear more than their fair share of decarbonisation costs.

[12] Other forms of hydrogen production, such as electrolysis, are also possible but have not been assessed in this report.

the regulated network tariff. The costs of the other parts of the infrastructure chain would also need to be borne, ultimately, by customers.

The current stakeholder environment and regulatory framework

Establishing policy recommendations in relation to network regulation requires a clear understanding of the current roles and responsibilities of different stakeholders in the sector.

We assessed this in relation to three different stakeholder groups: decision-makers; companies; and customers. We sought to identify the drivers of behaviour for these stakeholder groups, and the main issues which would be relevant to achieving any of the scenarios for each of them. Our assessment was based on our own review and understanding of the stakeholder environment, as well as discussions with stakeholders themselves.

Our main conclusions in relation to each stakeholder group are set out in the table below. This review helped to inform our conclusions and policy recommendations.

KEY MESSAGES IN RELATION TO STAKEHOLDER ENVIRONMENT

Decision-makers

- Currently a lack of clear allocation of roles and responsibilities across decision-makers, resulting in a lack of co-ordination and potentially unfair distortions across different energy vectors.
- No clear allocation of responsibility or governance framework for localised decision-making.

Companies

- Current class of investors (primarily pension funds) are on the more risk-averse end of the investor spectrum. This type of investor is more likely to be resistant to changes which introduce greater uncertainty/volatility in returns, and will likely exert influence on network behaviour with a view to ensuring stable and predictable returns.

Customers

- Achieving customer buy-in is likely to be central to securing ongoing political and regulatory support for decarbonisation efforts in any scenario.
- One way to achieve this will be to ensure a strong customer voice in decision-making (e.g. around conversion to low carbon district heat or hydrogen) which may currently be lacking.
- Customers will also be reluctant to engage with change if it results in unfair outcomes across different customer groups and creates arbitrary winners and losers.

We have also provided the CCC with a detailed assessment of the current regulatory framework in GB. We sought to identify important aspects of this framework; and any issues which may represent a barrier to the achievement of decarbonisation scenarios. Our main conclusions are set out in the table below.

KEY MESSAGES IN RELATION TO REGULATORY FRAMEWORK

- Ofgem will launch an important consultation in December 2018 which will set the policy context for the RIIO-GD2 and T2 reviews, covering the 2022-2029 period.
- The commitment to RAB recovery is strongly held in GB – unreasonable or ill-justified stranding of assets is unlikely.
- Levers around the “speed of money” offer Ofgem a reasonable degree of flexibility to accelerate or slow down the pay-down of RAB.
- Outputs incentives give Ofgem the ability to target and incentivise specific network behaviours – the overall incentive framework offers wide scope for Ofgem to drive specific/localised outcomes.
- In 2014/15 alone, nearly 60,000 new customers were connected to the gas network. Currently networks are legally obliged to connect new customers where a connection is requested.
- Ofgem is also incentivising networks to continue connecting fuel-poor customers to gas – with a target of over 91,000 customers in the GD1 period (of which c.27,000 have already been connected).
- Ofgem is currently reviewing the innovation funding framework for networks. Identification of cross-vector research funding is required.

Conclusions and policy recommendations

To identify a set of policy recommendations for BEIS and Ofgem, we have drawn together our work covering:

- an understanding of the main network characteristics and costs under each scenario;
- an indication of the likely change in network tariffs and the risks to investors in each scenario;
- an assessment of issues in the current stakeholder environment, and drivers of outcomes arising from the network regulation framework.

Based on these inputs, we have identified policy recommendations which can be grouped under three headings:

- Key immediate recommendations for Government policy;
- Low-regrets actions for Ofgem at GD2/T2; and
- Medium term requirements for policy and regulation.

We set out our recommendations in each area in turn below, before placing these recommendations in the context of an overall timeline.

Key immediate recommendations for Government policy

At present, a wide number of scenarios could feasibly materialise. This poses a problem for network regulation since the scenarios entail materially different network usage profiles. This has consequences for the activity that can and should be undertaken by Ofgem and network companies – for example, there is little point investing significant effort in modifying network codes to facilitate a hydrogen switchover if a hydrogen scenario is unlikely to materialise.

We have therefore identified three policy recommendations, which could be developed within the next few years, and would serve to reduce uncertainty, thereby enabling Ofgem and others to develop the regulatory framework appropriately.

Recommendation 1: Government will need to make policy decisions that will determine the direction of heat decarbonisation.

Achieving wide-scale heat decarbonisation will not be possible without Government making certain key decisions to determine the way in which heat will be decarbonised. This will be particularly important when customer choice is being limited.

This is most evident in any hydrogen scenario. We believe that Government would need to mandate a hydrogen switchover because:

- large groups of customers will need to be switched off natural gas and on to hydrogen at the same time, since the same pipe infrastructure cannot transport both hydrogen and methane simultaneously – meaning there is no prospect of effective individual consumer choice (at least between methane and hydrogen);
- the sequencing and co-ordination required for an efficient national hydrogen switchover would entail a number of challenges if local decision-makers governed the choice of whether to switch; and
- if switching to hydrogen entails higher costs to customers (at least initially) relative to remaining on methane, then allowing customers the choice to not switch could undermine decarbonisation objectives.

Similar decisions are also likely to be required for the non-hydrogen scenarios – in part because of the sheer scale and speed of customer switching that would be required in these scenarios. In addition, there are important customer affordability and fairness issues that will arise across the different heating technologies (given they have different mixes of upfront and ongoing costs). These will need to be taken into account and addressed on a national basis. We believe this must be led by Government.

Without such decisions, the credibility of certain decarbonisation scenarios (and particularly hydrogen) will be diminished. This has the potential to undermine the ability of industry, Ofgem, and other stakeholders to undertake the necessary planning and research required to deliver decarbonisation - including the need to develop appropriate network regulation.

Recommendation 2: Government should establish a clear framework for decision-making by 2020.

A significant source of risk to the achievement of any decarbonisation scenario is the current lack of clarity surrounding decision-making. BEIS should identify what decisions need to be made over the next 5-10 years in delivering decarbonisation scenarios; the timeline of such decisions; and the role different stakeholders should play in making those decisions, in particular, who is ultimately responsible.

This should include identifying the roles and responsibilities of Ofgem; devolved Governments; Local Authorities; industry; other Government Departments and BEIS itself. Crucially, BEIS should also identify how best to engage customers (or their representatives) in the decision making process, particularly where it involves removing individual customer choice.

The processes that are put in place must be capable of delivering the scale of decisions required in the available timeframes: this ability to deliver timely decision-making is something generally thought to be lacking in current industry processes[13].

Recommendation 3: A significant programme of research must be implemented and funded now, to enable informed decisions to be made in the 2020s.

Given the set of decisions that will need to be made, a programme of further research will be required to ensure those decisions are well-informed.

This begs two further questions.

- **Question 1:** What are the right questions to be asked as part of the low-carbon heating research programme – and who should be answering them?
- **Question 2:** How much funding for this research is needed, and where will it come from?

In relation to **question 1**, there are a number of important strategic questions for Government that would serve to reduce the uncertainty across scenarios:

- Will there be a role for CCS in the UK's future energy mix?
- Will hydrogen be economically and technically feasible?
- How can the electricity system manage the extreme seasonal swings in demand that will be required with the electrification of heating?
- What is the role and scope for other forms of heat decarbonisation?

To a large extent, these decisions are intertwined. The question of whether a hydrogen switchover will represent the best option for the UK will depend (among other things) on the viability and availability of CCS infrastructure; and the potential costs associated with alternative forms of decarbonisation (both of heating and of other sectors in the economy).

As part of this research, there is likely to be a central role for pilot tests/demonstrators of different models and technologies. This research would not only improve understanding of the costs, but also of customer behaviour aspects and acceptance of different forms of roll-out.

In relation to **question 2,** there is funding available: from the Network Innovation schemes administered by Ofgem, as well as more general innovation funding from Government.[14] Whether this will be sufficient (particularly in light of the

[13] We understand that this is something the IET is looking at, following on from its Future Power System Architecture (FPSA) project.

[14] This is both funding from central Government, such as DECC's innovation programme which has promised funding of £500 million over 5 years, as well as funding from the Devolved administrations (such as the Scottish Government's Local Energy Challenge Fund).

cancelation of the CCS demonstration and any loss of European funding following Brexit) and will be targeted to schemes of greatest value is something that will have to be kept under review. Ofgem is currently evaluating its innovation funding and the CCC should consider the conclusions when they become available. As well as ensuring that the level of future funding is not diminished, the CCC may also want to follow-up on the following points.

- **Cross-vector funding.** A number of the questions that will be relevant to improving understanding of the future use of the gas network will require innovation outside of the gas networks themselves. If the benefits to the trialling lie outside of the networks, Ofgem's current funding criteria would make it difficult for such schemes to be funded, even though the results of the trials may be in the interests of gas network customers. Since Ofgem's NIC and NIA schemes are such a large part of the available funds, there is a question whether the innovation funding is being directed where it could be of most value.
- **Stage of innovation.** Ofgem has chosen to focus funding on projects at high Technical Readiness Levels (TRLs) that, in addition, may be expected to deliver customer benefits in the near term. Since the question of future use of the network is one that stretches over a long timeframe, there is a question whether such a focus is appropriate.

Low-regrets options for Ofgem while uncertainty persists

The upcoming RIIO reviews are expected to be launched in December 2018, and concluded by December 2020. It is unlikely that key strategic Government decisions - which will have a material impact on the requirement for UK network infrastructure - will be made before this review is completed.

This means the current uncertainty is likely to be a feature of Ofgem's price reviews. As a result, in the near term, regulation should seek to ensure that the options across scenarios remain as open as possible.

The following set of policy recommendations are likely to be "low-regrets" actions which could be implemented by Ofgem at RIIO-GD2/T2. We consider these recommendations would strike a balance between keeping options open and reducing potential barriers to achieving any of the scenarios.

Recommendation 4: Identify a clear approach to allocating stranding risk between customers and companies.

For investors in network infrastructure, stranding risk is likely to be an important issue at the upcoming regulatory reviews, given the uncertainty around future gas scenarios. The prospect of asset stranding in the future has the potential to stymie investment now – depending on whether investors perceive this risk to be material; and whether they are adequately compensated for the risks they bear. The treatment of stranding risk must therefore be considered carefully in the context of needing to keep options open - since some scenarios will require ongoing investment and possibly even expansion of the gas networks.

Normally, regulators seek to allocate risks to the party who is best able to manage or mitigate that risk. This may be with the network investors, for example if they are able to influence the utilisation of their assets. However, there are also likely to be some scenarios in which the network companies will have limited ability to manage stranding risk – for example, in a hypothetical scenario where Government mandated mass switching away from gas to alternative electric heating sources. Similarly, in some cases the networks will be asked (or even legally mandated) to undertake investments[15] which they will only recover over a long time period under the current regulatory model[16]. In these instances, the networks' ability to make a commercial investment decision is constrained – i.e. they might be forced to make investment decisions which they would not otherwise have made, given the stranding risk.

Such situations could mean a higher cost of capital is required to finance investment, if stranding risk is left with network investors. Alternatively, if the network companies have limited ability to manage the risk, Ofgem could implement measures to transfer some or all of this stranding risk to customers. This could be achieved by accelerating the recovery of investment through changes to the depreciation profile, asset life, and/or capitalisation rate. Other options for transferring stranding risk would likely require changes to legislation, including:

- transferring (part or all of) the gas network RAB to electricity networks, to be recovered from electricity customers;
- introducing new charges to energy customer bills (similar to "Public Service Obligation" charges); or
- government guarantees that any stranded assets resulting from Government policy will be funded (potentially by the taxpayer).

Ultimately, Ofgem should seek to make clear its policy on asset stranding, including identifying:

- the circumstances in which investors would bear stranding risk vs. when investors would be protected; and
- the vehicle by which any protection from stranding risk could be expected to arise.

Ofgem's allowed cost of capital must then be consistent with its conclusions and policy around how stranding risk is allocated. Clear policy positions on these issues will allow investors to better understand the risks they are being asked to bear.

Recommendation 5: Introduce appropriate uncertainty mechanisms to the RIIO controls that will allow re-openers at relevant trigger points.

The next price control periods will cover the years 2021 – 2028. Our recommendations for Government policy (and the required timelines for this) imply that significant strategic decisions may be made within this period which

15 For example, the ongoing Iron Mains Replacement Programme is legally mandated through the Health and Safety Executive (HSE). Similarly Ofgem may require companies to undertake a particular network reinforcement investment, or to target a certain number of fuel poor connections.

16 At present, the recovery of investment is spread over 45 years, although the recovery profile is "front loaded".

would require networks to begin planning and investing for a particular decarbonisation pathway.

Ofgem should therefore ensure that the duration of the RIIO control period does not unduly prevent networks from being able to adapt rapidly to such strategic changes. This means that the price control will need to include trigger points to allow Ofgem or the networks to re-evaluate the price control allowances within the control period. Such triggers might be specified as, for example, a Government decision on a mandated hydrogen switchover; or a clear emerging requirement for network decommissioning to begin with the price control period.

Recommendation 6: Develop understanding of decommissioning costs and approach to regulating these costs.

It is likely that under any scenario, there will need to be some network decommissioning. In scenario 2 there is a prospect that a significant proportion of the grid (both distribution and transmission) could be decommissioned. It is apparent from our discussions with stakeholders and review of existing evidence that there is material uncertainty surrounding the costs and benefits associated with decommissioning the network. In particular, it is not clear whether the HSE would impose certain constraints on decommissioning; whether assets could be re-purposed for alternative uses (not involving gas transportation); and to what extent the existing network configuration would constrain any decommissioning.

We consider that Ofgem could instruct the gas networks to develop a decommissioning strategy, and an assessment of potential decommissioning costs and benefits under Scenario 2. This could be a requirement for the networks well-justified business plans, which are expected to be submitted to Ofgem in summer 2019. Ofgem would need to set out the requirements for this in its Strategy decision (expected March 2019). Ofgem could then evaluate and scrutinise information on decommissioning costs and benefits provided by GDNs, for example through benchmarking and independent expertise.

We also recommend that Ofgem should consider options for regulating decommissioning costs as part of the GD2 and T2 review. For example, Ofgem could consider whether there is a case for directly charging customers who are disconnecting from the grid for any direct decommissioning costs arising; or whether such costs should be socialised across remaining grid customers (or some other form of cost recovery).

Recommendation 7: Review of the current connections framework.

As part of Ofgem's Fuel Poor Network Extensions (FPNE) scheme, Ofgem sets targets for the number of fuel poor customers which the GDNs must connect to the gas networks. The GDNs currently have a target to connect over 91,000 fuel-poor customers in the period 2013-2020.

Connecting fuel poor customers to the gas grid plays an important role in alleviating fuel poverty in the UK. At the same time, it is possible that further programmes to connect customers could run counter to scenarios which require customers to come off gas. Ofgem should re-assess the trade-off between these issues as part of the GD2 review.

In addition, as part of the FPNE scheme Ofgem has recently required networks to provide information to prospective fuel-poor connecting customers on the costs of alternative heat sources before making any new connection. Ofgem should consider whether this requirement could be extended to cover any new connection to the grid. As part of this Ofgem should assess how effective the extension to the FPNE scheme has been, and whether customers have found this information useful (or whether it has materially affected their choices). This could be an effective way of ensuring information about alternatives to gas is available to customers.

Recommendation 8: Targeting gas network stakeholder engagement during business planning.

As part of developing well-justified business plans, Ofgem currently requires the network companies to demonstrate that a variety of stakeholders have been involved in the development of those investment plans. At the first round of RIIO price reviews, Ofgem noted that these incentives had been effective in improving the quality and effectiveness of stakeholder engagement by the networks.

For the next review, GDNs should be encouraged to demonstrate engagement with Local Authorities and other interested parties in relation to heat alternatives as part of their business planning for the GD2 period. GDNs should also be incentivised to develop an ongoing strategy for such engagement. This should help to improve co-ordination across different heat vectors.

Similar business planning requirements could be introduced to ensure GDNs and the NTS co-ordinate effectively with electricity networks, to develop consistent planning assumptions to inform investment forecasts.

Policy and regulation into the 2020s

The requirements for policy and regulation into the 2020s will depend, in part, on the outcomes of the RIIO reviews and the research programmes and policy proposals set out above. Broadly speaking, the main issues can be split between scenarios involving a hydrogen switchover, and non-hydrogen scenarios (although there is some crossover between these).

In the event that the Government decides to proceed with a mandated hydrogen switchover, a number of steps would automatically follow.

- **Recommendation 9: Government and Ofgem to adapt industry standards/network codes, and Ofgem's duties.** Changes would need to be made to the legal and regulatory framework to reflect a situation where both methane and hydrogen were in use. We expect that BEIS and Ofgem would need to consider what would be required in this area (and the timelines for any changes) shortly after the GD2 and T2 reviews are concluded (i.e. early 2020s).
- **Recommendation 10: Ofgem to establish the market and regulatory arrangements required for the provision of hydrogen.** This includes allocating responsibility/ownership for each part of the supply chain; and developing the regulatory and market model that would govern the interactions across the chain. Again, much of this work will actually be

needed before any Government decision on the hydrogen switchover could be made – which indicates this would need to be undertaken in the early 2020s.

- **Recommendation 11: Government needs to consider how best to protect consumer interests in the event of a switchover.** For example, it would be inefficient for customers to purchase a replacement gas boiler or a new gas cooker, only to then find that these appliances would need to be replaced or modified shortly afterwards. Government and industry would need to develop suitable public information campaigns, and consider whether specific protection (including financial support) needs to be put in place for vulnerable customers resulting from mandated changes. Given the timelines involved, we expect action in this area would need to be initiated in the early 2020s.

- **Recommendation 12: Government to decide on geographical coverage of any hydrogen switchover.** This decision does not necessarily need to occur at the same time as the initial "yes/no" decision, since the roll-out is likely to be phased across regions. Such a decision could feasibly be taken in the late 2020s.

Alternatively, in the event that a hydrogen switchover is not mandated, a different set of policy questions will arise. Two issues in particular are worth consideration.

- **Recommendation 13: Government to re-consider the legal requirement to connect customers.** Under the Gas Act, GDNs are under an obligation to connect any customer to the grid who requests a connection[17]. In scenarios where customers will need to switch away from gas, Government may wish to re-consider this obligation, and place more restrictions on connecting customers.

- **Recommendation 14: Government and Ofgem to assess options for furthering the objective of creating a level playing field for competition.** This would include, in particular, the application of carbon pricing to emissions from burning natural gas in homes; or continued subsidy of competing technologies to compensate for the absence of a carbon price on gas.

- **Recommendation 15: Government to evaluate the effectiveness of zoning and the need for co-ordinated switching.** Our Scenario 2 is based on the assumption that there is co-ordinated switching away from gas networks to alternative electric sources, driven by either local or central Government. Such co-ordination would certainly facilitate decommissioning of the networks. However, it is possible that decommissioning could also be achieved absent co-ordination[18]. Zoning and co-ordinated/mandated

[17] Specifically, gas transporters are required to comply, so far as it is economical to do so, with any reasonable request to connect any premises to the network. Gas Act 1986, Schedule 9 - General powers and duties. In addition, under Schedule 10 - Duty to connect certain premises, customers residing within 23m of an existing gas main (and on the ground floor) are entitled to a gas connection at the standard network charge.

[18] For example, in areas where non-co-ordinated switching has occurred, the network companies could be incentivised, through the RIIO controls, to identify areas of the networks where inefficiently low numbers of customers remain on-grid, and develop mechanisms by which both those customers and the network companies could share in the efficiency benefits of decommissioning.

switching to alternative technologies might be necessary or beneficial for other reasons but we have not considered this question in this report. We note, however, that the Heat Networks Development Unit is already funding work by Local Authorities to undertake zoning and heat mapping; and DECC recently announced a new scheme to support investment in heat networks (the Heat Networks Investment Project[19]). It is likely that Government should review how effective this has been in any non-hydrogen scenario. The timing of such a review is likely to arise in the mid- 2020s.

- **Recommendation 16: Consider modifying Ofgem's role to become a heat regulator rather than regulator of a specific fuel.** Some industry commentators have noted that Ofgem's focus on regulating methane provision creates distortions to the level playing field for alternative providers of heat, and have proposed that Ofgem's role should be broadened to cover all heat sources. In our previous report for the CCC, we concluded that there was no urgent need for such a policy in relation to district heating networks[20]. We have not considered this question further as part of this report. However, if hydrogen is not viable, there would be a stronger case for thinking about this policy change ahead of the RIIO-GD3/T3 reviews.

Timeline

Ofgem's upcoming price review will be undertaken between 2018 and 2020, and will determine revenue and cost allowances for the period 2021-2028. Further, under the Fixed-term Parliaments Act 2011, the current Parliament is expected to run to 2020.

The next few years therefore offer an opportunity for Government to put in place the necessary programme of research that will be required to inform decision-making in subsequent Parliaments. Ofgem, in the meantime, will need to implement regulatory solutions which ensure options remain open at the next reviews.

Scenarios 3 and 4 assume that hydrogen would start to come online by 2025. However, we understand from CCC that it may be more realistic to assume that hydrogen would be required by 2030. Given the expected construction and development lead times, we believe that a Government "yes/no" decision for hydrogen would be required 3-5 years in advance of the hydrogen being made available. Therefore, a Government hydrogen decision would be needed sometime between 2025-27 to allow hydrogen infrastructure to be operational from 2030.

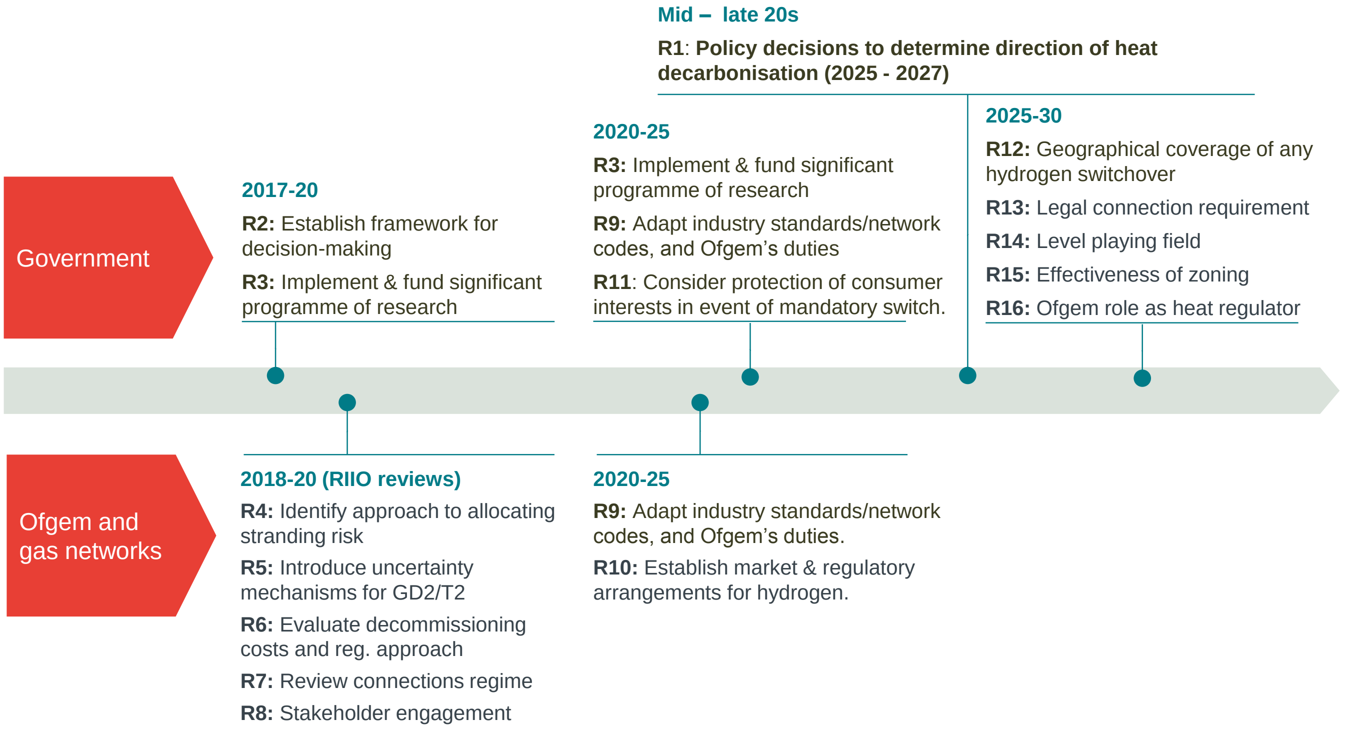
If this is the case, a hydrogen decision is unlikely to be made by the time of the next price reviews, but could well affect network requirements before the GD3/T3 reviews. This is why Ofgem should ensure there is sufficient flexibility in the GD2 and T2 controls.

[19] https://www.gov.uk/government/news/governments-central-heating-for-cities-scheme-to-bring-energy-bills-down

[20] https://www.theccc.org.uk/wp-content/uploads/2015/11/Frontier-Economics-for-CCC-Research-on-district-heating-and-overcoming-barriers-Annex-1.pdf

Our remaining recommendations fall into place around these key decision points. This timeline is illustrated in Exhibit 4.

Exhibit 4. Timeline for decision-making



1 INTRODUCTION

The Committee on Climate Change (CCC) is responsible for advising Government on cost-effective pathways to achieving the UK's emissions reduction targets. In 2015, the Committee advised on the level of the 5th Carbon Budget, which covers the period 2028 – 2032.

The 5th Carbon Budget envisaged different scenarios that would enable the UK to meet its emissions targets for 2050 - namely to reduce Greenhouse Gas (GHG) emissions by 80% on 1990 levels[21]. These scenarios represent holistic analyses, based on internally consistent combinations of different technologies which could deliver carbon reductions across different sectors of the economy.

Meeting the 2050 target has implications for the future of the gas transmission and distribution networks. As part of its scenario analysis, the CCC set out projections for the demand for natural gas to 2050. The demand scenarios show that the volume of throughput on the networks, and the nature and location of network usage, is likely to change significantly under the various decarbonisation scenarios. In this project, the CCC wishes to characterise and assess the potential impacts on the gas networks of these longer term demand scenarios.

Gas distribution and transmission companies are regulated by Ofgem, with costs recovered through consumer bills. Regulation of the networks will need to be adaptable, so as to facilitate changes in network costs and the nature of network usage. Ofgem will also need to ensure that its regulatory framework does not act as a barrier to achievement of decarbonisation targets; or as a disincentive to the network companies to playing a full and appropriate role in decarbonisation.

The next price control reviews are known as RIIO-GD2 (for gas distribution networks) and RIIO-T2 (for gas transmission)[22]. In these price reviews, Ofgem will set network cost allowances and determine the incentive framework for the period 2022 – 2030. These reviews will be an important factor in determining whether the gas network is prepared for low-carbon transition.

This report seeks to enable the CCC and other stakeholders to begin consideration and understanding of the issues they need to be aware of going into the GD2 and T2 reviews.

In particular, we have been asked to explore the regulatory and institutional challenges associated with four possible scenarios for the future of the gas grid:

- **Scenario 1 (Central)** is consistent with the CCC's central scenario in the 5th Carbon Budget. Gas use declines to around 50% of its present level by 2050, but the gas grid is largely still required to service the remaining demand. For the purposes of our analysis, we assume this includes areas where pipes are kept in place to meet peaks in demand arising from the use

[21] CCC, 2015. *Sectoral scenarios for the 5th Carbon Budget*; CCC, 2012. *2050 target: achieving an 80% reduction including emissions from international aviation and shipping*

[22] RIIO-T1 will also simultaneously set price limits for the GB electricity transmission networks.

of hybrid heat pumps[23]. This scenario also assumes that Carbon Capture and Storage (CCS) is operational, gas demand for power generation continues, and most of the decline in aggregate demand arises in the buildings sector.

- In **Scenario 2 (Low Gas)**, gas use declines more rapidly, falling by over 80% by 2050 relative to today. This is based on the premise that there is no CCS technology available. We assume that demand reductions are facilitated by co-ordinated and planned switching to alternative heating technologies such as low carbon district heat networks and heat pumps. This means that large portions (potentially 80%) of the gas grid can be decommissioned[24].
- In **Scenario 3 (National Hydrogen)**, the potential for hydrogen to replace natural gas as a fuel for domestic heating and consumption is realised. A national switchover from natural gas to hydrogen is undertaken with the existing grid being re-purposed to carry hydrogen and continuing to service a large amount of demand. For hydrogen to result in a reduction of carbon emissions, it must be combined with CCS technology[25].
- In **Scenario 4 (Patchwork Hydrogen)**, the switchover to hydrogen is confined regionally to areas in northern England, where hydrogen infrastructure is most likely to be economic as a result of geological constraints which limit the location of available CCS and hydrogen storage capacity. There is a ‘patchwork’ switchover, where parts of the distribution grid are converted to carry hydrogen; parts of the grid are decommissioned; and parts service the remaining demand for gas.

Currently the CCC considers that all of these scenarios are possible on the path to a low-carbon economy in the UK.

The purpose of this report is not to compare across scenarios with a view to recommending a least-cost pathway or identifying the “right” solution for the UK. Such an assessment would depend on a large number of factors, including (but not limited to) the level of emissions abatement that can be achieved in other sectors of the economy; the success of rolling out heat pumps, heat networks and energy efficiency; the development of Carbon Capture and Storage (CCS) as a route to low-cost hydrogen; the viability of hydrogen itself; the need to ensure security of supply and replace the daily and seasonal energy storage capacity that would be lost if there were significant decommissioning of the gas networks; and, crucially, customer acceptance and willingness to switch to new technologies in any of these scenarios[26].

[23] The CCC’s 5CB Central scenario does not include hybrid heat pumps, but the CCC notes that hybrids could be part of the future mix.

[24] For our scenario analysis, we assume 80% of distribution network is decommissioned by 2050. We understand there may be alternative uses for the NTS in future (e.g. transporting US LNG through Europe via interconnector). We therefore assume that 50% of the NTS is decommissioned, but that network costs associated with alternative NTS uses are not socialised across UK domestic gas customers.

[25] This is based on assuming that Steam Methane Reformation (SMR) is the primary source of hydrogen production. In future, it is possible that other forms of hydrogen production – notably through electrolysis – could become more cost-effective, which would mean CCS technology would not be required.

[26] A recent report by a set of industry experts at Imperial College Centre for Energy Policy and Technology (ICEPT) undertook a more detailed comparison of system costs of alternative solutions. See Managing Heat System Decarbonisation, Comparing the impacts and costs of transitions in heat infrastructure, April 2016. http://provpol.com/wp-content/uploads/2016/05/Heat-infrastructure-paper.pdf

Instead, the purpose of this report is to evaluate whether aspects of the current regulatory and institutional framework for regulating the gas networks would need to be reformed to meet each scenario[27]. The project therefore has three main aims:

- To review the current regulatory and institutional framework relating to the gas network, and assess the extent to which it is capable of both managing, and adapting to different decarbonisation scenarios.
- To determine the key issues going in to the next gas network price control review in order to prepare for low-carbon transitions, along with the immediate implications for Government.
- To establish what is required over the next 5-10 years in order for Government to be in a position to set out a strategy for the future of the gas grid to 2050, including the role of hydrogen for heat.

The rest of this report is structured as follows:

- In Section 2 we provide a summary of our work advising the CCC on the characterisation and key features of the current regulatory model and stakeholder environment. A fuller slide pack which formed the central output from this work is provided as Annexe 2.
- In Section 3 we describe the four demand scenarios we have tested in more detail.
- In Section 4 we set out our assumptions and projections for network costs associated with each scenario, covering both the gas distribution and transmission networks.
- In Section 5 we show the results from our shadow regulatory model which projects network tariffs to 2050; and other key parameters such as the outstanding Regulated Asset Base (RAB). These results draw on the demand scenarios described in Section 3 and the associated cost projections described in Section 4.
- In Section 6, we draw out key implications of the scenario analysis and identify recommendations for government and regulatory policy.

Throughout the project we have engaged with relevant stakeholders to discuss our evolving progress and emerging findings. We have received very valuable input from Ofgem; DECC; the Energy Technologies Institute (ETI); the Energy Network Association (ENA) Gas Futures Group; and National Grid. We wish to express our thanks to those individuals who have been involved and we hope this report serves to spark further debate and discussion on the way forward for the UK gas sector and its regulation.

This research is being undertaken as part of the CCC's broader 2016 work programme on heat and energy efficiency policy.

[27] This work does not consider whether there are any regulatory or institutional changes resulting from the recent UK referendum decision to leave the EU, or the extent to which this result could affect the achievement of decarbonisation objectives.

2 CURRENT STAKEHOLDER ENVIRONMENT & REGULATORY MODEL

One of the CCC's central objectives for this project was to understand the issues it needs to be aware of going into the next RIIO price control reviews for gas distribution (GD2) and transmission (T2). These reviews are currently expected to be finalised in December 2020, and will determine network cost allowances, revenues, and incentives for the period 2021 – 2028.

As a key input to this, the CCC asked us to review and characterise the current stakeholder environment and regulatory model. In particular we were asked to review the incentives for the main stakeholders; and to help further the CCC's understanding of certain key parts of the regulatory model, including:

- how assets are incorporated into the regulated asset base;
- how depreciation of existing assets work; and
- the potential implications of assets becoming stranded.

Our output for this part of the project is contained in two slide decks, which are attached as Annexes.

- Annex 1 sets out our high-level review of the current stakeholder environment and institutional arrangements. We identify issues which are likely to affect the ability or role of each group of stakeholders in meeting climate objectives[28].
- Annex 2 sets out our review of the current regulatory framework, focussing on the key areas of economic regulation of networks under Ofgem's RIIO model; the wider legislative and safety framework which affects network behaviours; and the current innovation funding framework.

In this section we provide a brief summary of this work, drawing out the key conclusions in relation to the stakeholder environment and regulatory model in turn. This section therefore provides relevant context and background to the analysis and policy recommendations contained in later sections.

In general, we have sought to identify gaps or potential barriers to the achievement of future decarbonised scenarios, which pertain to the institutional and regulatory arrangements for networks. Clearly a significant barrier at present to achieving wider switchover to alternative technologies is the cost to customers associated with switching. However, this report is not concerned with the question of when or how alternative technology cost reductions might arise – we restrict our assessment and policy recommendations to possible reforms of the regulatory arrangements.

[28] The scope of our review is constrained to Ofgem, which regulates the energy networks in GB. A different regulator operates in Northern Ireland, namely the Northern Ireland Utility Regulator (NIAUR). The context in Northern Ireland is markedly different to GB, since the devolved government continues to support further efficient expansion of the gas network; and the regulatory regime has been established to focus on achieving connections and deferring network costs to future customers. We have therefore not directly considered the effect of the future scenarios on the Northern Ireland regulatory and institutional framework in this report.

Having identified some of the key issues with the current institutional and regulatory arrangements in this section, we use these identified gaps/issues to inform our policy recommendations in Section 6.

2.1 Stakeholder environment

In Annex 1 we identify the relevant stakeholders according to whether they are key decision-makers; companies; or customers. These are shown in Exhibit 5 below.

Exhibit 5. Stakeholder environment

Source: Frontier Economics

In this section we describe the key issues with the current institutional arrangements which will affect the role of these stakeholder groups in meeting climate objectives. These are summarised in the table below.

KEY MESSAGES IN RELATION TO STAKEHOLDER ENVIRONMENT

Decision-makers

- Currently a lack of clear allocation of roles and responsibilities across decision-makers, resulting in a lack of co-ordination and potentially unfair distortions across different energy vectors.
- No clear allocation of responsibility or governance framework for localised decision-making.

Companies

- Current class of investors (primarily pension funds) are on the more risk-averse end of the investor spectrum. This type of investor is more likely to be resistant to changes which introduce greater uncertainty/volatility in returns, and will likely exert influence network behaviour with a view to ensuring stable and predictable returns.

Customers

- Achieving customer buy-in is likely to be central to securing ongoing political and regulatory support for decarbonisation efforts in any scenario.
- One way to achieve this will be to ensure a strong customer voice in decision-making (e.g. around conversion to low carbon district heat or hydrogen) which may currently be lacking.
- Customers will also be reluctant to engage with change if it results in unfair outcomes across different customer groups and creates arbitrary winners and losers.

2.1.1 Decision-makers

Fairness across vectors

One potential barrier to increasing switchover to alternative technologies is that the current regulatory model can introduce distortions which undermine the creation of a level playing field on which alternative technologies can compete.

To take an example, under the 1986 Gas Act, existing gas networks are currently legally obliged to provide a gas connection to customers who request it[29]. No such provision exists for alternative heat sources. Ofgem has made modifications to encourage more competition in connections, and to ensure that gas networks consider whether customers are better off with gas or with alternatives, although this is limited to fuel poor connecting customers.

Co-ordination across vectors

The current decision-making environment involves a number of different bodies with different remits. This has the potential to undermine the achievement of decarbonisation scenarios.

One such co-ordination issue relates to the HSE's role. The HSE's mandated Iron Mains Replacement Programme is currently driving the majority of

[29] Specifically, gas transporters are required to comply, so far as it is economical to do so, with any reasonable request to connect any premises to the network. Gas Act 1986, Schedule 9 - General powers and duties. In addition, under Schedule 10 - Duty to connect certain premises, customers residing within 23m of an existing gas main (and on the ground floor) are entitled to a gas connection at the standard network charge.

investment in gas distribution network infrastructure. Ofgem and the HSE worked together at the last price review to develop appropriate funding mechanisms and allowances for this work. But in future, in scenarios where the gas network is less utilised after 2030, the continuation of a replacement programme up to that point would likely be unnecessary and inefficient.

Enhanced co-ordination could also be needed across the transport and energy sectors. For example, if UK transport strategy was predicated in wide-scale availability of hydrogen for use as a fuel for transport, this could require Ofgem's approach for gas networks to reflect a similar objective.

Localised action and decision-making

There is currently little clarity on the opportunities and responsibilities of local decision-makers in achieving de-carbonised future scenarios. For example, Local Authorities currently have no formal role in identifying homes, streets or towns/cities which could potentially switch to alternative low carbon district heating solutions. Although Local Authorities can choose to undertake research into introducing district heating zones (and some funding is available from DECC to support this), there is no formal requirement for Local Authorities to do so, which is likely to result in patchwork coverage.

A related important issue is the need for governance structures which allow Local Authorities to co-ordinate with each other – this is most likely to be needed in the event of more wide-scale switching to alternative technologies such as hydrogen.

2.1.2 Existing gas network companies

Cost of capital and risk appetite

The current GB network regulatory framework has established a track record for stable, predictable returns and the security of the Regulated Asset Base (RAB). The nature of the businesses and regulatory environment to-date has attracted low-cost finance; and equity investors which include a number of pension funds.

One of the implications of the CCC's future scenarios is that the recoverability of network investment, and the regulatory response to the changing technology environment, will become more uncertain. In some scenarios, gas network provision will essentially be competing with alternatives such as low carbon district heating and heat pumps; while in other scenarios involving hydrogen, the role of the network could potentially change significantly.

Arguably, this greater uncertainty will result in the need for a different type of investor in GB networks with a greater risk appetite. It could also imply changes to the cost of capital required to compensate investors for taking on businesses facing longer term stranding risk, particularly if ongoing investment in the HSE's replacement programme is mandated in the near-term.

National Grid has announced its intention to sell its four gas distribution networks[30]; and further transactions are possible[31].

Network-led innovation

Ofgem is undertaking a review of its current innovation funding framework under RIIO; and a wider set of funding options are potential available to network companies to undertake research.

2.1.3 Customers

Inter-generational fairness, winner and losers

The impact on consumer prices is central to any decision-making around switching technologies, whether that decision is taken nationally; regionally; or by customers individually.

A key question across the scenarios is how this can be achieved in a way which distributes the burden of achieving emissions reductions fairly across customers – either in time or in different areas of the country. For example, if decisions are made nationally which imply customers in different parts of the country will be forced to face different costs for their energy consumption, there is likely to be a detrimental effect on customer buy-in which could de-rail efforts to decarbonise. Options could be considered for how to smooth or cross-subsidise any such effects, so that the costs of decarbonisation are more evenly spread.

Ultimately the choice across these options will depend in part on what is the most fair/acceptable allocation of costs.

Achieving buy-in and giving customers a voice in decision making

In today's regulatory and institutional framework, there is a sense in which customers are still without a strong representative voice. This is particularly true in local decision-making, where there is no clear line of responsibility for who might make decisions such as switching to a low carbon district heat network or to a hydrogen alternative; or accountability for those decisions.

Ofgem has made significant strides in encouraging the network companies to engage with stakeholders under the RIIO framework, both as part of their long-term business planning, but also on an ongoing basis.

However, it is unlikely that any of the four scenarios we have considered for this report can materialise without a high degree of customer buy-in. This is both because switching to alternative technologies is likely to imply higher cost to customers relative to the status quo; and because of the likely disruption caused by such switchovers. For example, under any hydrogen conversion scenario there are likely to be supply interruptions as a result of the need to purge the

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30 https://www.ofgem.gov.uk/publications-and-updates/open-letter-sale-national-grid-s-gas-distribution-networks-business

31 See, for example, recent news reports of SSE's intention to sell a stake in Scotia Gas Networks (SGN). http://uk.reuters.com/article/uk-sse-results-idUKKCN0Y90KB

existing network of methane; and the need to convert to hydrogen-burning appliances in homes[32].

In this regard, we note that it will be essential to learn relevant lessons from similar types of switchover elsewhere – for example resulting from the smart meter roll-out; the superfast broadband roll-out; and even going back to the conversion from town gas to natural gas in the UK in the 1960s and 70s. Valuable lessons could also be derived from processes of conversion from H-Gas to L-Gas in Europe[33].

Sustainability First is currently leading a programme of work "New Energy and Water Public Interest Network" ("New-Pin") involving, *inter alia*, Ofgem; Ofwat; some of the energy and water network companies; and consumer and other public interest bodies. This is looking at how "public interest" should be determined in the energy and water sectors, particularly given the changes these sectors are likely to face[34]. Among other important questions, this work is intending to consider how the "customer and public voice" is heard in making wide strategic decisions, such as what heating technologies should be available.

2.2 Current regulatory framework

The CCC asked us to review and characterise the current regulatory framework related to the UK gas grid. The purpose of this is to establish the strategic context and evidence base to evaluate whether policy or regulatory reforms need to be made.

We set out our review of the current regulatory framework, focussing on three components:

- **economic regulation** of the gas networks under Ofgem's RIIO model, including an explanation of how price controls are set (both in terms of timescales and process);
- the **wider legislative and safety framework** which affects network behaviours; and
- the current **innovation funding** environment.

We discuss the key conclusions in relation to each of these in turn below. Further detail is provided in Annex 2.

32 Although we have not measured this for the present report, it would be possible for the CCC to attempt to measure the customer cost of such disruption by estimating the value to customers of lost load.

33 e.g. Belgium and Germany.

34 Information on the NEW-PIN programme is available here: http://www.sustainabilityfirst.org.uk/index.php/new-pin

KEY MESSAGES IN RELATION TO REGULATORY FRAMEWORK

- Ofgem will launch an important consultation in December 2018 which will set the policy context for the RIIO-GD2 and T2 reviews, covering the 2022-2029 period.
- The commitment to RAB recovery is strongly held in GB – unreasonable or ill-justified stranding of assets is unlikely.
- Levers around the "speed of money" offer Ofgem a reasonable degree of flexibility to accelerate or slow down the pay-down of RAB.
- Outputs incentives give Ofgem the ability to target and incentivise specific network behaviours – the overall incentive framework offers wide scope for Ofgem to drive specific/localised outcomes.
- In 2014/15 alone, nearly 60,000 new customers were connected to the gas network. Currently networks are legally obliged to connect new customers where a connection is requested.
- Ofgem is also incentivising networks to continue connecting fuel-poor customers to gas – with a target of over 91,000 customers in the GD1 period (of which c.27,000 have already been connected).
- Ofgem is currently reviewing the innovation funding framework for networks. Identification of cross-vector research funding is required.

2.2.1 Economic regulation under RIIO

In this section we draw out relevant information for the CCC's purposes of considering and influencing policy ahead of the RIIO-GD2[35] price control review.

We discuss in turn:

- the process and timelines for setting a price control, including explanation of how investment is planned and allowed;
- the degree of flexibility which Ofgem has in determining allowances, customer bills, the speed of investment recovery, and targeting outputs; and
- the incentives currently placed on networks to connect new gas customers.

Process and timelines for a review

As set out in the RIIO Handbook, Ofgem's expectation is that a RIIO price control review process will take 30 months. Some of the key staging posts in this process are as follows:

- **Stage 1:** Ofgem initiates the price control review with a consultation on its Strategy Document. This is a key document which kicks off the review, in which Ofgem sets out its expectations of the issues it intends to address at the upcoming review; and consults on specific policy proposals[36].
- **Stage 2:** The network companies develop and submit business plans to Ofgem, which set out their investment proposals for the forthcoming review period and the associated proposals for outputs. The business plans are

[35] RIIO stands for **R**evenue set with **I**ncentives to deliver **I**nnovation and **O**utputs

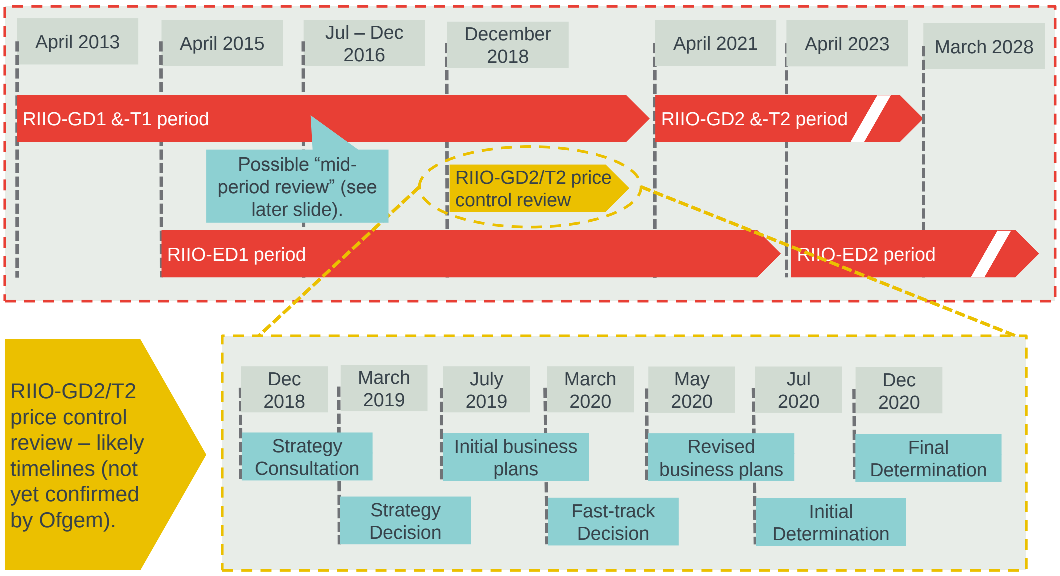
[36] For example, at the GD1 review Ofgem's Strategy document confirmed the required network outputs (and how these would be incentivised); the strength of the cost efficiency incentive; and the method for estimating the Weighted Average Cost of Capital (WACC) (including an estimated range).

developed in accordance with guidance set out by Ofgem in the Strategy Decision.

- **Stage 3:** Ofgem reviews and scrutinises the business plans, and uses various benchmarking techniques to assess the cost efficiency of the companies. Companies which Ofgem deems have particularly compelling and demonstrably efficient business plans are "fast-tracked" – meaning their business plan costs are allowed in full; the review is concluded early for these companies; and an additional financial reward is provided. Fast-tracking incentives have proved to be strong drivers of behaviour in the first RIIO reviews.
- **Stage 4:** Companies that aren't fast-tracked re-submit revised business plans based on feedback from Ofgem. The plans are then submitted to a further round of scrutiny and efficiency analysis by Ofgem. Finally, Ofgem publishes a Draft Determination set of proposals for investment allowances; and following consultation Ofgem makes a Final Determination of the allowances for the forthcoming period.

Based on the experience from the previous reviews and Ofgem's guidance on RIIO timelines, in Exhibit 6 below we set out the expected timelines for the next price reviews. We note that Ofgem is yet to confirm these timelines.

Exhibit 6. Potential timelines for RIIO-GD2/T2 reviews.



Source: Frontier Economics

Exhibit 6 shows that the Strategy Consultation for the next reviews can be expected to begin in December 2018, with a Strategy Decision issued in March 2019. The importance of this consultation should not be under-stated – it generally sets the tone for the review and identifies the key parts of the price review work programme. The issues which Ofgem intends to address during the price review will generally all be contained in this document.

Another example of the importance of the Strategy Consultation is that it is expected to include the guidance Ofgem provides to the companies for developing their investment proposals and business plans. The Strategy

Consultation also establishes the criteria Ofgem will use to assess business plans to determine whether any of the network companies merit fast-track rewards. In general the networks will seek to ensure they have met all the guidance and requirements established by Ofgem for business planning – so if there are issues it is important for the networks to address in their plans, this would ideally be made clear in the Strategy Decision.

Components of the regulatory model and degree of flexibility

Ofgem's regulatory model converts allowed cost forecasts into revenue allowances, and ultimately into tariffs. There are many features of the RIIO model that allow Ofgem a wide degree of flexibility in determining network costs and the impact on customer bills. Exhibit 7 below sets out some of the key conclusions around the flexibility offered by different components of the RAB model.

We do not expect that the CCC's role will involve detailed comment and input on the particular technical parameters of the price control framework. However, some aspects that it is likely to be useful for the CCC to consider are as follows.

In general, the regulatory model offers a significant degree of flexibility for Ofgem to influence network behaviour; target particular outcomes; and smooth the impact on customer bills.

The underlying assumption at present is that the economic life of assets is long, with depreciation charges spread over 45 years. Although the profile of this depreciation was changed at the last review for gas distribution companies, this remains a long time-period over which investment is recovered, given that the CCC's scenarios imply significant changes within the next 10-15 years.

Exhibit 7. Summary of key points in relation to economic regulation framework

RAB	▪ Certainty, stability and predictability of RAB is a core tenet of UK regulation – supported by Ofgem and CMA. ▪ This has resulted in cheap financing; and has attracted more risk-averse equity investors such as pension funds. ▪ Stability and long-track record is supportive for investment – but fundamental changes could be needed in a world of falling demand and increasing competition from alternative technologies.
Speed and profile of investment recovery	▪ Value which enters RAB does not depend on identified capital expenditure. Ofgem sets a % of total cost which is capitalised, irrespective of whether the network actually spends opex vs. capex. However Ofgem generally sets the capitalisation rate roughly to match the expected opex-capex split. ▪ Lowering the capitalisation rate will have the effect of allowing speedier recovery of new investment (and vice versa). ▪ Ofgem also sets the asset life and depreciation profile assumptions. These affect the speed of investment recovery (and hence the impact on bills). ▪ Ofgem has already amended depreciation profiles, asset lives, and capitalisation rates in response to long-term demand uncertainty in GD1. These levers offer significant flexibility. Ofgem could go further if necessary.
Financing and allowed WACC	▪ Methodologies for estimating WACC are reasonably well-established – e.g. Ofgem is unlikely to change its cost of debt mechanism under RIIO. ▪ WACC is a key headline parameter in a price control and Ofgem could be sensitive to PR implications of allowing higher returns (should that be necessary to attract a less risk-averse class of investor). ▪ Stranding risk will be an important consideration at GD2 for setting the WACC.
Duration of control	▪ 8 year controls are probably beneficial for encouraging longer term thinking and giving stronger incentives for innovation. ▪ However, this also means there is less opportunity for Ofgem to respond to changes and fewer opportunities for CCC/Govt. to influence regulation.
Cost Assessment	▪ Benchmarking models have been developed by Ofgem over long time. ▪ Engineering analysis & judgement also inform investment allowances. ▪ Shift to 'totex' approach intended to move away from micro-management and avoid specific sign-off of investment projects – but this is easier for distribution vs. transmission.
Outputs and incentives	▪ Network performance is monitored and incentivised across 6 primary output areas. This is unlikely to change, but there is plenty of flexibility for Ofgem to specify particular outputs and targets within these categories. ▪ 'Secondary deliverables' are an important driver of investment behaviour. Ofgem should ensure these targets are consistent with long-term demand scenarios.
Uncertainty mechanisms	▪ Given the CCC's demand scenarios, the GD2 review is likely to be characterised by continuing uncertainty about which scenario the networks should prepare for. ▪ There is likely to be a need to adapt quickly to alternative demand scenarios. A well-specified uncertainty mechanism can be effective for ensuring that the price control allowances do not preclude rapid changes in network operations.

Source: Frontier Economics, See Annex 2 for more details and context.

Incentives to connect customers

Two features of the current regulatory framework currently encourage the network companies to connect customers to the gas grid:

- First, under the Gas Act 1986 (as amended in1995), network companies are currently obliged to comply, as far as it is economical to do so, with any reasonable request to connect any premises to the gas system.
- Second, under Ofgem's Fuel Poor Network Extensions (FPNE) Scheme, network companies are given targets to connect fuel poor customers to the gas grid, and fuel poor customers are provided with subsidies with a view to covering (or at least reducing) the cost of a grid connection.

The FPNE scheme merits particular attention. During the GD1 review, Ofgem committed to reviewing this scheme and ensuring it was consistent with wider Government objectives and support schemes. Ofgem published a final decision on amendments to the scheme in September 2015[37].

Over the GD1 period, the GDNs have a target to connect over 91,000 fuel-poor customers to the network. By the second year of the price control, 2014-15, the GDNs had actually achieved over 27,000 of these connections[38], meaning the GDNs were ahead of target. Ofgem has stated that the GDNs will be financially rewarded/penalised if they beat/miss these targets – receiving a reward/penalty worth 2.5% of the incremental/avoided costs of making those connections.

One of the amendments made by Ofgem in September was that the companies which facilitate the FPNE scheme (in partnership with the GDNs) were required to evaluate whether it would be cost effective to connect fuel poor customers to the gas network rather than to alternative forms of fuel for heating. The scheme was also extended to provide subsidies to fuel poor customers who connect to a district heating network supplied by CHP.

These amendments effectively acknowledged that the scheme, as previously specified, potentially distorted outcomes, since GDNs were provided with incentives to connect fuel-poor customers directly to the gas network; and no incentive to consider alternatives. However, the amendments beg further questions about whether Ofgem could have gone further in driving networks to consider switches to lower-carbon alternatives:

- Although the scheme was extended to include district heat networks, Ofgem chose not to set targets for district heat connections, on the basis that most of the GDNs did not consider there would be any district heat connections in the GD1 period.
- The amendments left open the question of how the GDN partners would actually go about assessing the cost of alternative technologies on behalf of customers; or establishing any standards for how these alternatives should be communicated. Ofgem acknowledged that this could lead to regional variation in the quality of this assessment, and asked that industry worked together to share best practice. It is not clear whether this requirement is

[37] https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/fpnes_3009_published_2_0.pdf

[38] https://www.ofgem.gov.uk/system/files/docs/2016/03/riio-gd1_annual_report_2014-15_final.pdf

proving effective in practice, or if customers continue simply to choose the gas network.

The intention of the FPNE scheme is to reflect a “social obligation” on the GDNs to facilitate reductions in energy bills for fuel-poor customers. However, that objective may not be consistent with a need to reduce gas consumption over the medium term, since alternative technologies are currently unlikely to reduce bills (relative to gas). Ofgem will review the FPNE scheme at the next review, and it is likely to be important that the CCC contributes to that review to consider its consistency with climate objectives.

The existence of the FPNE also begs a wider question around the GDNs incentives to connect other customers (i.e. those who do not suffer from fuel poverty). Currently we are not aware of any obligation on the network companies to do a similar test of alternative technologies for non-fuel-poor customers who wish to connect. In 2014/15, the total non-fuel-poor connections were as follows:

- 17,695 new housing customers;
- 26,973 existing housing customers;
- 2,373 non-domestic customers.

Inevitably there will also be disconnections during these periods, and the numbers above do not net these off. Nevertheless, fuel poor customers represented only 21% of total connections in that year.

The appropriate approach to connections for the GD2 period will depend on a number of factors. Connecting customers to the existing grid system is not a problem for decarbonisation in the event that the networks can largely be re-purposed to supply hydrogen. But additional connections in the short-term will create more barriers in future if hydrogen is not a viable option, meaning customers will need to switch away from gas.

2.2.2 Wider legislative framework

Much of the network activity in the gas sector is dictated by necessarily stringent safety rules and regulations. In particular:

- The HSE currently mandates the network companies to replace certain at-risk iron mains pipes (the ‘repex programme’). Repex is expected to continue to be largely mandatory investment until the 2030s. But, in scenarios where network throughput falls from the 2030s onwards, it could be inefficient to continue a repex programme which replaces ageing iron pipes with new polyethylene plastic pipes with an expected technical lifetime of 60 years or more. The flip side is that polyethylene pipe is in fact ***required*** in any scenario which involves a switchover to hydrogen. As such, continued repex investment will prove a beneficial contributor to a hydrogen switchover.
- Gas Safety Management Regulations and network codes currently dictate minimum technical standards and specifications for the networks, based on assuming that methane enters the existing transportation network. In the event that the networks are re-purposed for alternative uses, there is likely to be a need for a significant programme of code modifications.

Exhibit 8. Key conclusions for CCC around wider legislative framework

Safety and Reliability Requirements	▪ HSE-driven requirements currently impose large investment, replacement and maintenance requirements on networks. ▪ Network codes would need to be re-written or modified for different uses of the gas network. ▪ HSE will require extensive R&D to ascertain safety impacts of transporting hydrogen through pipeline infrastructure required for hydrogen scenarios.
Consumer protection requirements	▪ Licence conditions set minimum standards of performance for networks & qualification requirements for workers that access customer premises. ▪ We do not expect these to change for different uses of the gas network. However, a hydrogen conversion may impose material operating expenditures to networks to meet the legislative requirements for skilled workers.

Source: Frontier Economics

2.2.3 Innovation

The gas sector is in the middle of two major transformations driven by:

- the switch to low carbon; and
- the shift from analogue to digital operation.

The importance of innovation has therefore increased in recent years, following a period of limited interest in the early decades that followed privatisation. Indeed, there is likely to be a need for continued funding of innovation to determine the appropriate future use of the gas network for the foreseeable future. This is driven by the continued uncertainties associated with the most effective way to deliver decarbonisation, and the barriers that exist to it happening absent intervention.

It was outside of the scope of our project to undertake a full review of innovation in this sector. However, in Annex 2 we provide a high level summary of the ongoing requirement for innovation funding; innovation mechanisms that Ofgem administer (the Network Innovation Allowance, Network Innovation Competition and the Innovation Roll-Out Mechanism); and an overview of alternative funding mechanisms, which draws on our work with Sustainability First to review innovation funding in the energy sector.[39]

Ofgem is currently undertaking its own review of the future of network innovation, the results of which are not available in the timeframe of our project.

There are two particular issues that the CCC may want to follow-up on once the results of this review are known given their importance to the future of the gas grid.

- **Cross-vector funding.** A number of the questions that will be relevant to improving understanding of the future use of the gas network will require innovation outside of the gas networks themselves. This is the case for the

[39] See http://www.sustainabilityfirst.org.uk/images/publications/gbelec/Paper%2011%20%E2%80%93%20How%20could%20electricity%20demand-side%20innovation%20serve%20customers%20in%20the%20longer%20term-%20Frontier%20Economics%20&%20Sustainability%20First%20-%20April%202014.pdf

likely programme of innovation required to understand hydrogen potential[40]. However, to be able to understand how hydrogen compares to alternative options, funding for other large scale trials of alternative technologies (such as the Energy Systems Catapult's Smart Systems and Heat Programme) is also important.

If the benefits to the trialling lie outside of the networks, Ofgem's current funding criteria would make it difficult for such schemes to be funded, even though the results of the trials may be in the interests of gas network customers. Since Ofgem's NIC and NIA schemes are such a large part of the available funds, there is a question whether the innovation funding is being directed where it could be of most value.

- **Stage of innovation.** Ofgem has chosen to focus funding on projects at high Technical Readiness Levels (TRLs) that, in addition, may be expected to deliver customer benefits in the near term. Since the question of future use of the network is one that stretches over a long timeframe, there is a question whether such a focus is appropriate.

[40] We understand that the Leeds Citygate project will be setting out the programme of innovation funding it considers will be required going forward, along with where this funding might come from.

3 DESCRIPTION OF DEMAND SCENARIOS

The CCC has developed four scenarios for the future of gas demand to 2050 which are consistent with meeting the target GHG reduction of 80% on 1990 levels. We consider these scenarios represent a set of plausible alternatives; and each scenario is sufficiently different that they merit individual consideration in relation to the question of network regulation.

Two of the scenarios we consider are identical to scenarios in the CCC's 5th Carbon Budget (5CB) advice. These project declining gas demand, where natural gas is replaced by alternative technologies such as heat pumps and heat networks. The other two scenarios involve a switchover from methane to hydrogen[41].

The purpose of this report is not to comment on the relative merits/demerits of the different scenarios for the UK as a whole. Our scope is also limited to consideration of the impact on gas network regulation – undoubtedly the four scenarios also have implications for other sectors (particularly electricity) which are not considered in this report.

The remainder of this section describes the gas demand profiles for each scenario in turn. More detail is provided in 5CB[42], while in this section we are only providing a high level summary.

3.1 Scenario 1 (Central)

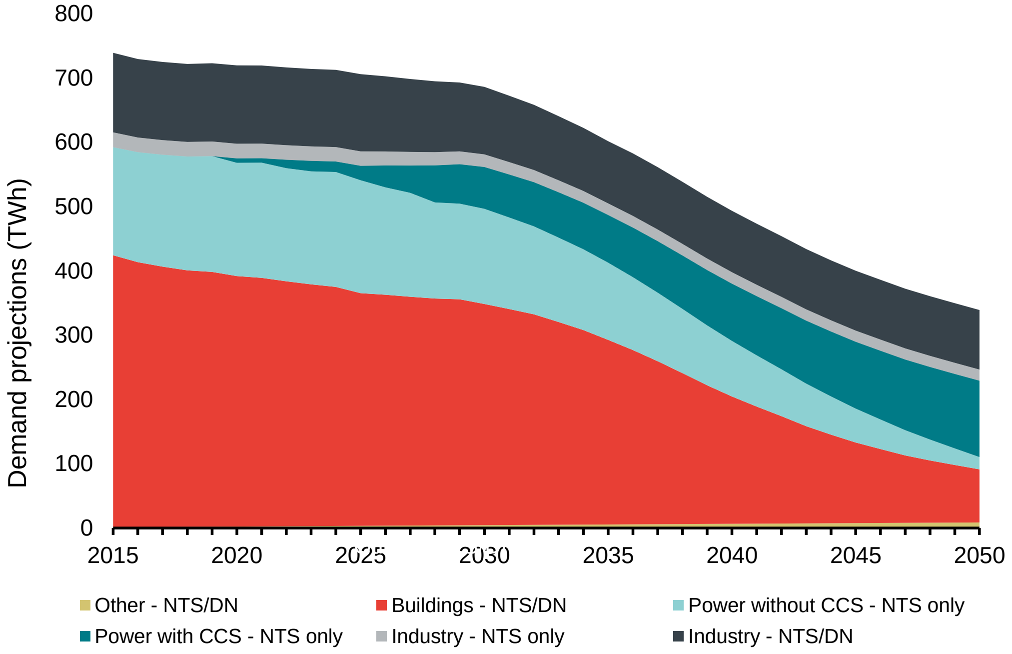
This is the CCC's central scenario, which is the CCC's best estimate of the technologies and behaviours that are needed during the 5th Carbon Budget to meet the target.

Exhibit 9 shows the breakdown of gas demand in this scenario split by use (i.e. buildings demand, industry demand, power and other) as well as indicating whether that demand is transported through the distribution networks (DN), the transmission network (NTS), or both.

41 We have not considered scenarios involving the use of biogas. Biogas could be part of a decarbonised future energy mix (or at least useful as a transitional fuel) in heating and/or transport. This is an area of active research in the industry, which in particular is considering whether biogas can be scaled. For example, a trial is underway in Swindon to demonstrate the technical and economic viability of producing green gas through the gasification of household waste. See: http://gogreengas.com/news/demonstration-plant-plans-underway/. Since the development of biogas is unlikely to entail significant new network infrastructure or changes in the use of the network, we consider it is less relevant to the question of whether regulatory reforms are needed (relative to the four scenarios we have tested).

42 CCC, Sectoral scenarios for the Fifth Carbon Budget, https://documents.theccc.org.uk/wp-content/uploads/2015/11/Sectoral-scenarios-for-the-fifth-carbon-budget-Committee-on-Climate-Change.pdf

Exhibit 9. Scenario 1 (Central) gas demand projection



Source: CCC's 5th Carbon Budget, Central scenario, provided by the CCC

In this scenario there is a continuing energy efficiency improvement across the economy, as well as a shift to low-carbon sources of energy demand beyond the power sector. The fall in total gas demand accelerates after 2030 - by 2050 aggregate gas demand is 54% lower than in 2015.

Gas demand declines most rapidly in the building sector, with demand being 80% lower in 2050 versus 2015. Buildings demand which is left by 2050 arises largely from customers on hybrid heat pumps[43]. In the power sector, this scenario assumes the development of carbon capture and storage (CCS) technology, meaning that gas-fired power generation continues to be viable in a low carbon world. Gas-fired power generation switches to CCS from 2020 onwards[44].

This scenario sees a continued role for most of the gas transmission and gas distribution network, to service the remaining gas demand by 2050. An underlying assumption is that switching behaviour is assumed to be un-coordinated (i.e. driven by the market). Therefore, the gas distribution network is required at its current scale, to supply customers that have not switched to alternative technologies as well as to meet peaks in demand, for example if customers have taken up hybrid heat pumps.

The reduction in baseload demand in this scenario suggests that the level and frequency of peaks in gas demand are lower after 2030 than today. Therefore, we expect the gas distribution network to cease any expansionary/reinforcement investment after 2030.

43 Hybrid heat pumps are heating systems that use a combination of an electric heat pump and a gas-fired boiler to supplement heating requirements at peak times.

44 CCC, Sectoral scenarios for the Fifth Carbon Budget, https://documents.theccc.org.uk/wp-content/uploads/2015/11/Sectoral-scenarios-for-the-fifth-carbon-budget-Committee-on-Climate-Change.pdf, page 22

The majority of the transmission network is also required to meet the demand profile in this scenario, particularly since the viability of CCS infrastructure means that gas-fired power generation will continue in the future. Nationally, however, the direction of gas flows is likely to change as North Sea production declines, meaning less gas flows from St. Fergus in Scotland to the rest of the country through the NTS. As a result, the scenario allows for some decommissioning of the NTS.

3.2 Scenario 2 (Low Gas)

This scenario is consistent with CCC's max scenario from the 5CB. It assumes a greater deployment of low carbon heat and energy efficiency options relative to Scenario 1, to make up for a shortfall in other sectors[45].

A total of 3.3 million heat pumps in 2030 are assumed to be deployed, relative to 2.3 million in the central scenario[46]. This scenario also assumes 54 TWh of heating demand is met by heat networks in 2030, relative to 33 TWh in the central scenario[47]. Both the central and max scenario see a more prominent role for heat networks after 2030[48]. Energy efficiency is also increased beyond the central scenario.

- The CCC's 5CB considers alternatives to the Max scenario that involve no CCS. The CCC has asked us to consider this "no CCS" world as our second scenario, since it is likely to pose different regulatory and policy questions.
- The CCC has also asked us to assume that the scenario involves co-ordinated switching, which enables localised grid decommissioning.

Exhibit 10 shows Scenario 2 gas demand projection.

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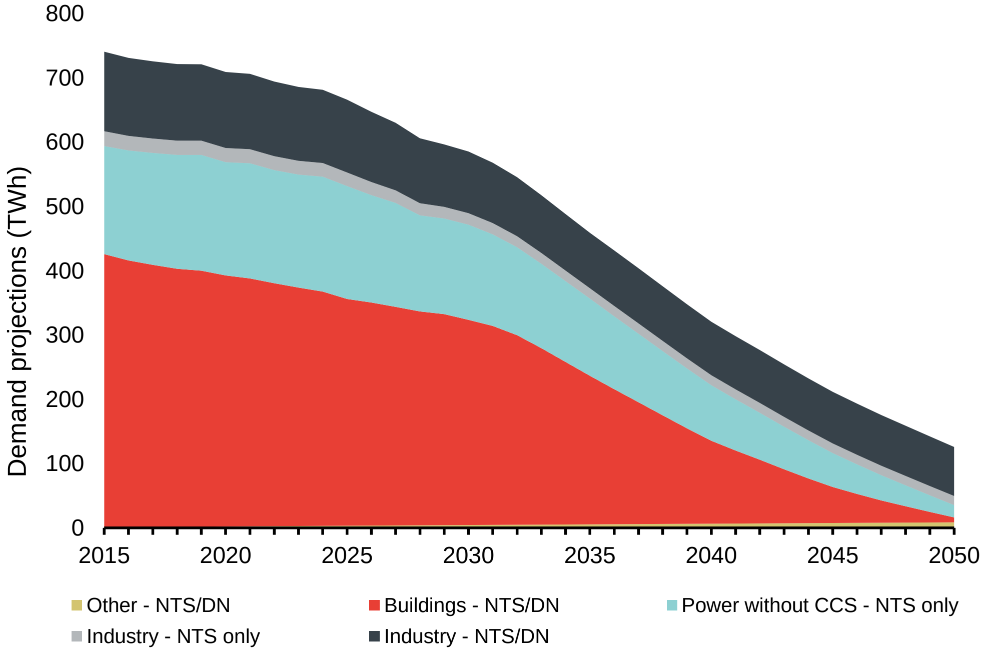
45 ibid, page 94

46 ibid, page 88

47 ibid, pages 24 and 94

48 ibid, page 90. The CCC commissioned a report by Element Energy on the potential for district heat networks by 2050 in November 2015 (https://d2kjx2p8nxa8ft.cloudfront.net/wp-content/uploads/2015/11/Element-Energy-for-CCC-Research-on-district-heating-and-local-approaches-to-heat-decarbonisation.pdf). Element Energy also wrote a report for DECC looking at whether heat pumps can be used as the heat source for district heat networks (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/502500/DECC_Heat_Pumps_in_District_Heating_-_Final_report.pdf).

Exhibit 10. Scenario 2 (Low Gas) gas demand projection



Source: CCC's 5th Carbon Budget, Max scenario – no CCS power, provided by the CCC

Total demand through the distribution network falls by 83% by 2050 relative to 2015. Buildings gas demand reduction is even steeper at 98% by 2050 relative to 2015. The low level of gas demand by 2050, as well as the assumption that there will be co-ordinated switching, will enable gas distribution networks to decommission large parts of the network by 2050.

Similarly, absent CCS technology, power generation moves largely away from gas fired plant by 2050. Total NTS demand drops by 83% in this scenario (as opposed to 54% in the central scenario). This means that there is more NTS decommissioning in this scenario.

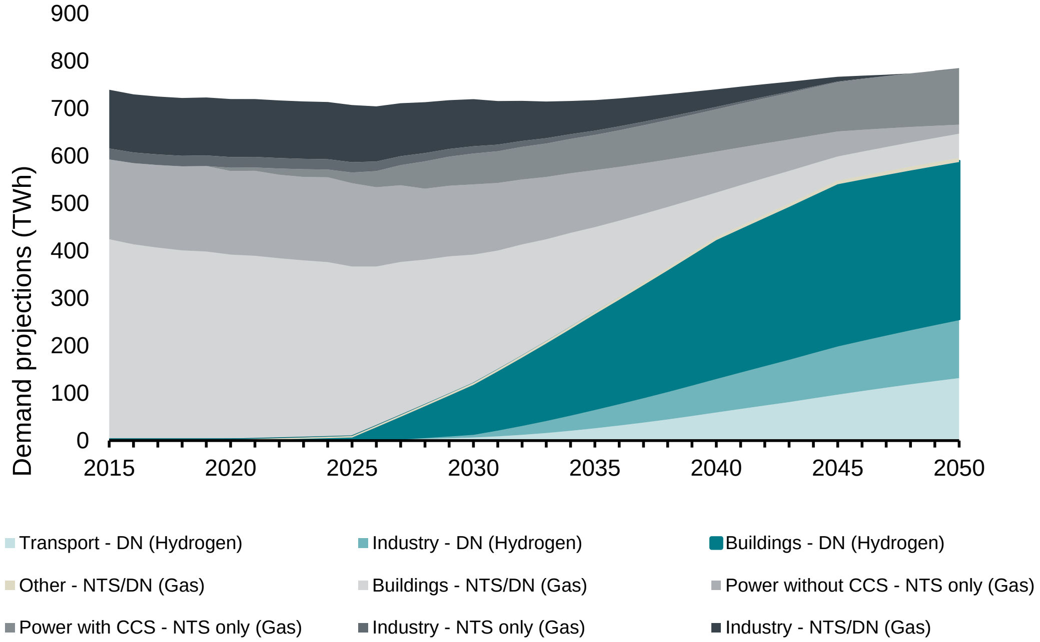
3.3 Scenario 3 (National Hydrogen)

In its 5th Carbon Budget, the CCC has looked at an alternative scenario in which a portion of the gas distribution network is converted to carry hydrogen instead of methane from around 2025. This involves the use of hydrogen boilers to generate heat in residential, commercial and public buildings[49].

For the purposes of this project, the CCC has undertaken some additional refinements relative to the 5CB, and has provided us with updated aggregate gas and hydrogen demand data for our scenario 3. This is shown in Exhibit 11.

[49] CCC, Sectoral scenarios for the Fifth Carbon Budget, https://documents.theccc.org.uk/wp-content/uploads/2015/11/Sectoral-scenarios-for-the-fifth-carbon-budget-Committee-on-Climate-Change.pdf, page 67

Exhibit 11. Scenario 3 (National Hydrogen) gas and hydrogen demand projection



Source: CCC's 5th Carbon Budget, Alternative scenario (additional edits by the CCC), provided by the CCC

In this scenario, 75% of total demand is serviced by hydrogen by 2050. Hydrogen penetration reaches 100% for industry[50] and 87% for buildings by 2050. The scenario assumes that up to 2025/2030, some customers switch to alternative technologies (such as heat pumps and heat networks), as well as some customers switching to hydrogen – all of which displaces gas boilers. After 2030, the CCC's assumption is that customers either switch to hydrogen or do not switch away from the gas networks.

Based on the data provided by the CCC on current demand in 380 GB cities and towns[51], we have developed a detailed city-by-city switchover plan. This switchover profile is calibrated to be geographically consistent (i.e. to follow a logical path from city-to-city based on proximity); and to match the aggregate hydrogen demand profile in scenario 3 as shown above. In all, 253 cities are assumed to have converted to hydrogen by 2050.

Storage capacity is a key determinant of the timing and geographical profile of a hydrogen switchover scenario. We currently expect that hydrogen would be stored onshore in underground salt caverns, although other forms of storage may be viable in the future.

As shown in Exhibit 12 a number of suitable storage facilities are concentrated in the north of England. We therefore assume that the first cities to convert to hydrogen are the North East, North West and Yorkshire regions, as suitable

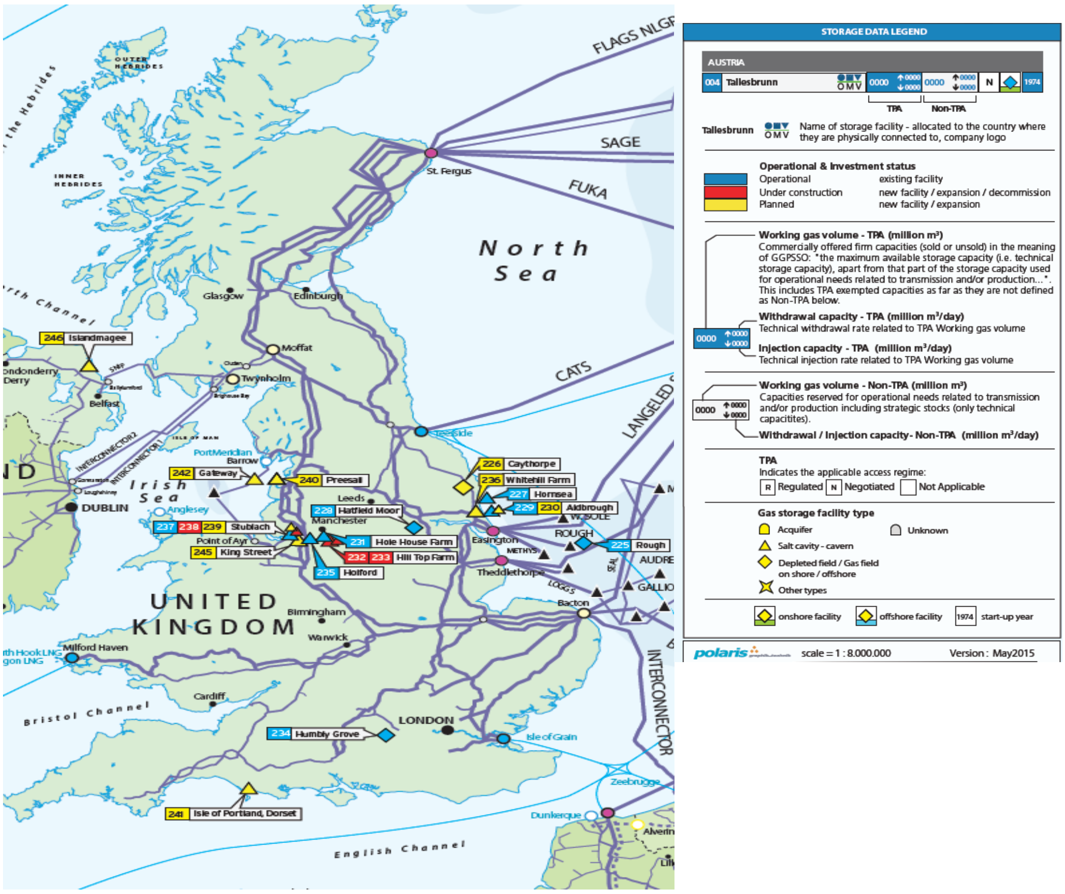
[50] We note that there is some uncertainty surrounding this assumption, since it is possible that some industrial consumers will utilise methane for specific technological processes for which hydrogen may not be suitable. However, we have proceeded on the basis of the assumptions provided by the CCC.

[51] Sourced from DECC, Gas sales and numbers of customers by region and local authority 2014, https://www.gov.uk/government/statistical-data-sets/gas-sales-and-numbers-of-customers-by-region-and-local-authority

storage facilities are concentrated in close proximity to these regions. This is also consistent with the fact that the H21 project involves detailed design research for converting the city of Leeds.

The H21 project includes a forward-looking think piece on how a national hydrogen switchover could be achieved. Demand in the south may be serviced by local storage options or via a new hydrogen transmission system[52].

Exhibit 12. Existing and planned storage facilities in the UK



Source: *Gas Infrastructure Europe (GIE), http://www.gie.eu/download/maps/2015/GIE_STOR_2015_A0_1189x841_FULL_wINFOGRAPHICS_FINAL.pdf*

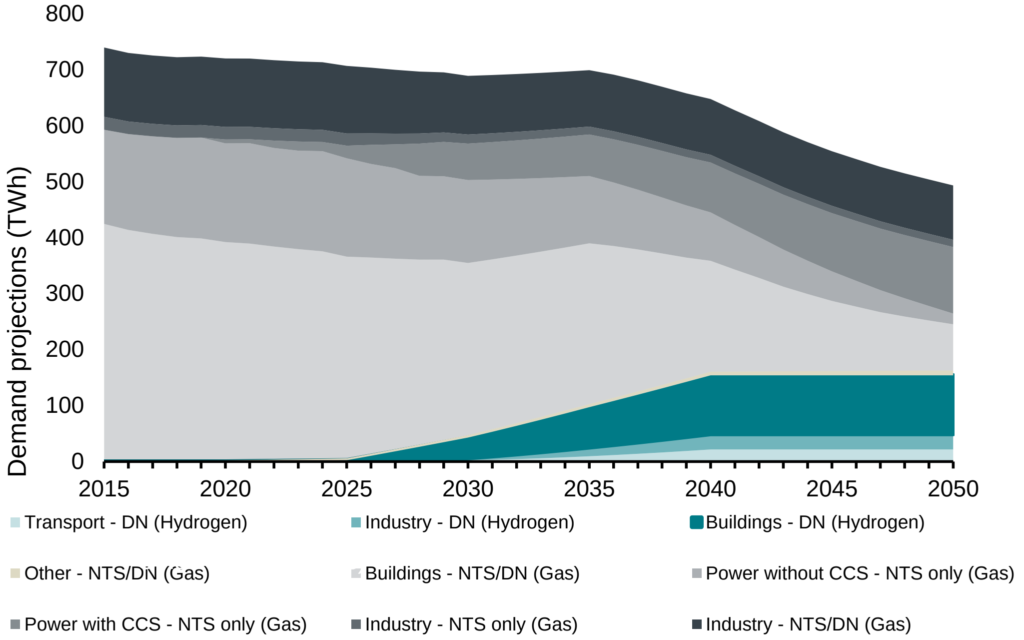
3.4 Scenario 4 (Patchwork Hydrogen)

This scenario envisages a regional switchover to hydrogen constrained to the north of England, where the majority of storage facilities are concentrated.

The total gas and hydrogen demand profile for this scenario is shown in Exhibit 13.

[52] The E4Tech report commissioned by the CCC also explores options for a full hydrogen switchover, including the possibility of a full hydrogen transmission system.

Exhibit 13. Scenario 4 (Patchwork Hydrogen) gas and hydrogen demand projection



Source: Provided by the CCC

Approximately 30% of total national demand is serviced by hydrogen by 2050 in this scenario. Similarly to Scenario 3, a hydrogen switchover requires CCS infrastructure. In this scenario, there is 154 TWh hydrogen demand by 2050, which equates to around 36Mt CO2 produced annually.

For the northern hydrogen regions, some customers switch to alternatives before 2025, after which all switching is to hydrogen. For the other regions, switching to heat pumps and heat networks is assumed to be in line with Scenario 1.

4 NETWORK COST IMPLICATIONS OF EACH SCENARIO

In this section, we set out the impact of the demand scenarios on grid operations and future gas network costs.

- First, we discuss the system costs which we expect would arise in a hydrogen scenario.
- Second, we set out the network cost forecasts we have used in each scenario.

For the purposes of this project, we have had to make a number of stylised assumptions on how different cost categories are expected to evolve in the future. Inevitably there is a degree of uncertainty surrounding the cost projections and the assumptions we have used. In Annex A we set out the main assumptions we have used and highlight the key uncertainties.

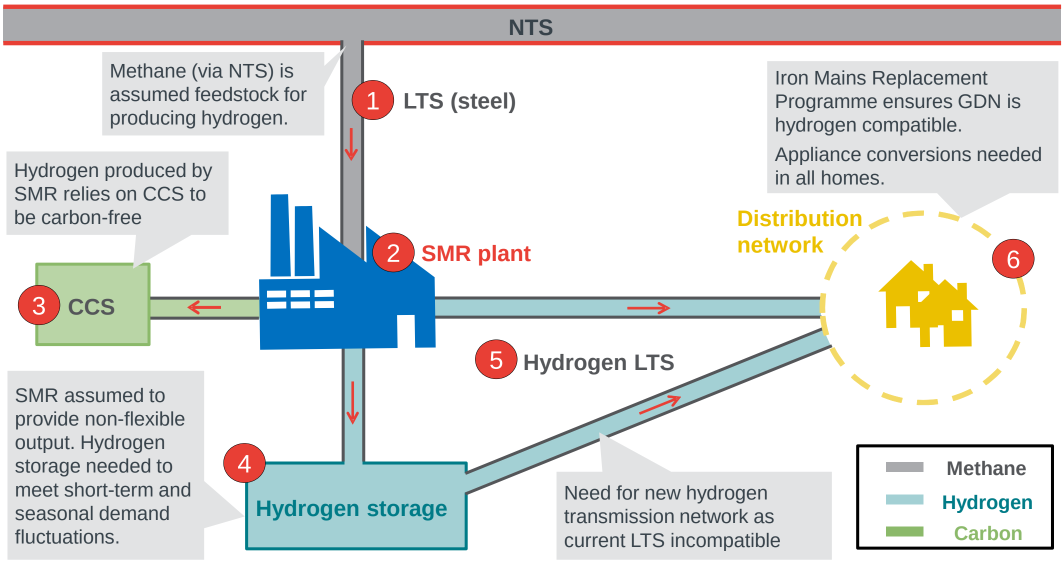
4.1 Hydrogen infrastructure costs

Scenarios 3 and 4 consider the roll-out of hydrogen networks on a national and regional level, respectively.

There is in general a shortage of alternative data sources on hydrogen costs. The H21 project in Leeds is the first research project to undertake a detailed appraisal of the technical viability of hydrogen; and an in-depth analysis of the infrastructure costs that would be required to supply a UK city with its heating requirements using hydrogen. We are therefore reliant on the H21 research for informing the cost forecasts. In some cases we have applied judgement to aspects of the H21 costs to make an assessment about how those costs might evolve in the longer term.

It is possible to identify with a reasonable degree of certainty what sorts of infrastructure would be needed for a hydrogen economy. Exhibit 14 sets out schematically what a UK hydrogen infrastructure could comprise of, and is described further below.

Exhibit 14. Hydrogen infrastructure schematic



Source: Frontier

The following key components of a hydrogen system would be required:

1. The production of hydrogen requires a natural gas feedstock, which could come from a number of sources[53]. For our purposes, we have assumed that natural gas continues to be provided via the NTS.

2. For the Leeds project, hydrogen production is assumed to take place in steam-methane reforming (SMR) plant. This is a well-established production process for hydrogen which is already used in other contexts. There are alternative ways to produce hydrogen, which may become more commercially viable in the future. SMR plant can potentially be connected direct to the NTS; or to the existing steel Local Transmission System (LTS) for the methane feedstock. The latter is illustrated in Exhibit 14.

3. One of the by-products of the hydrogen production process is CO_2. The attraction of hydrogen for decarbonisation is that, if carbon emissions can be captured at the source of hydrogen production (pre-burn), the hydrogen which is burned in homes is then carbon-free. As such, for hydrogen to be useful in achieving a low carbon economy, a Carbon Capture and Storage (CCS) infrastructure is essential.

4. The hydrogen production process is generally inflexible – SMR plant cannot efficiently flex production to match demand. Therefore another key component of a hydrogen economy will be sufficient storage capacity to allow system flexibility for both intraday and inter-seasonal variations in demand. Salt cavern storage is currently assumed in the H21 project, but other forms of hydrogen storage facility may become available in future.

[53] We assume that hydrogen is produced using steam-methane reforming (SMR) technology, although in future alternative hydrogen production technologies – such as electrolysis – could become cost effective, which would remove the need for methane feedstock or CCS infrastructure.

5. The H21 project has been modelled based on assuming that 240 km of high-pressure Hydrogen Local Transmission System (HTS) infrastructure is constructed to carry hydrogen from SMR plant in Teesside to the Leeds population centre, with a connection to storage facilities north of Hull. New infrastructure is required to transport hydrogen at these pressures because the existing high-pressure LTS is generally constructed of steel, and is therefore unsuitable for transporting hydrogen due to risk of hydrogen embrittlement. Future technology advances may mean the existing LTS and potentially the NTS could be re-purposed to transport hydrogen, however it is likely that the existing NTS capacity will be required to supply natural gas for hydrogen production.

6. At lower pressures, the H21 project demonstrates that the polyethylene pipe which is being installed as part of IMRP for local distribution is suitable for re-purposing to carry hydrogen. Since it is not possible for the same pipes to carry both methane and hydrogen, groups of customers would be required to switch to hydrogen simultaneously, according to the particularities of network configuration in the local area. In addition, existing home boilers and other methane-based appliances are currently not compatible with hydrogen, meaning the country will need to undertake a programme of appliance conversion to move to a hydrogen economy.

The various components of infrastructure, therefore, are reasonably clear – albeit there is some potential for developing technologies. The more significant uncertainty in relation to hydrogen infrastructure costs, however, is around identifying the required configuration and scale of infrastructure that would be needed to deliver regional or national hydrogen switchover.

To evaluate this would require an understanding of the potential combination and locations of SMR facilities across the country; the potential capacity and location of storage facilities which could be used for hydrogen; the economics of CCS infrastructure at different locations/scales; and technological development (e.g. in relation to hydrogen embrittlement and home appliance). There is also uncertainty around the source of the methane feedstock required to produce hydrogen.

Given this, we have sought to identify some reasonable high-level assumptions around the infrastructure costs associated with a hydrogen roll-out, based on the cost information for each infrastructure component resulting from the H21 project. We describe these below.

Capital costs

Capital costs include the costs for hydrogen production, storage, the hydrogen transmission system (H-LTS) and appliance conversion.

- **Hydrogen transmission system:** On the basis of cost estimates from the H21 project, the unit cost per km for building hydrogen LTS is £1.2 million. As we explained in Section 3.3, we have developed a phased city-by-city switchover assumption which is calibrated to match the CCC's hydrogen demand scenarios. We assume that, on average, the length of LTS network required for each incremental Local Authority area is approximately 10km. This corresponds to a total LTS network under a national hydrogen scenario (scenario 3) of 2,530 km[54]. This will correspond to c. 12 million per Local Authority area.

- **Hydrogen production:** In the H21 project the capital expenditure associated with building an SMR plant is assumed to be £395 million. We convert this to a per-GWh unit cost on the basis of annual hydrogen consumption for domestic and non-domestic customers in Leeds of 6,423 GWh per annum[55].
- **Hydrogen storage**: The H21 project estimated the cost of the storage facility for Leeds at £366 million. For simplicity we again convert this capital cost to a per-GWh unit cost, to project wider switchover costs.
- **Appliance conversion**: For Leeds, appliance conversion costs are anticipated to be £805 million to convert domestic and small commercial buildings[56]; and a further £248 million for converting industrial buildings. For simplicity, we convert this to a per GWh unit cost to generate the switchover cost forecasts.

Operating costs

Operating costs include costs for efficiency losses in conversion, SMR storage and carbon disposal are captured.

- **Efficiency losses in conversion**: There are energy efficiency losses associated with the process of converting methane to hydrogen. A portion of that is a result of the additional volumes of methane required to produce the equivalent amount of hydrogen energy in the Steam Methane Reformation process[57], the remainder is the power required to operate the SMR plants. The cost of purchasing these efficiency losses is assumed to rest with the SMR owner and therefore forms part of its operating costs. We have assumed that the total energy efficiency losses associated with conversion amount to 25%, which is less than the H21 estimate. Our estimate is based on anticipated process efficiencies that will be gained through the mass roll out of the SMR technology. For the H21 project, this calculation amounts to £14 million total operating cost or £2.2 million per GWh per annum.
- **SMR / Storage**: This reflects operational and maintenance costs required to run SMR and storage facilities. According to H21 these are approximately 4% of capex for the SMR and Storage infrastructure per annum. We have

[54] We consider the total hydrogen LTS required under scenario 3 a reasonable estimate, which is also in line with H21 view of the total hydrogen LTS required for a UK hydrogen rollout.

[55] DECC, Gas sales and numbers of customers by region and local authority 2014, https://www.gov.uk/government/statistical-data-sets/gas-sales-and-numbers-of-customers-by-region-and-local-authority

[56] This translates to an estimate of £3,078 per property, which is lower compared to KPMG's estimate of appliance conversion cost of £4,500 - £5,500 per property. Source: KPMG (July 2016), 2050 Energy Scenarios, http://www.energynetworks.org/assets/files/gas/futures/KPMG%20Future%20of%20Gas%20Main%20report%20plus%20appendices%20FINAL.pdf

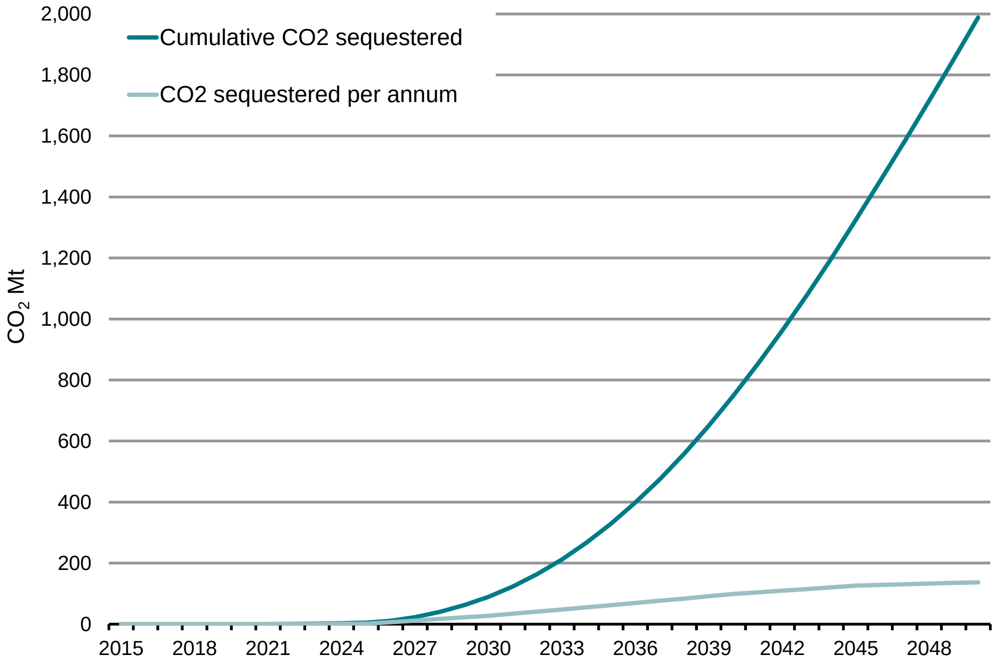
[57] H21 has assumed that approximately 25% extra methane supply is required to service a given amount of heating demand. To estimate these costs, H21 has taken a purchase price for methane from the Heren Index, i.e. the pure wholesale cost of purchasing gas.

assumed that on average these operating costs will come down over time as efficiency improves, and therefore assume operating cost of 2% of capex. This corresponds to £11 million in total, or £1.7 million per GWh[58] per annum.

- **Carbon capture and storage:** We assume the SMR owner will incur a charge per tonne of CO_2 produced for the use of CCS infrastructure. There is significant uncertainty around what carbon price would be needed to ensure that CCS is commercially viable, and it is beyond the scope of this project to assess that question. The H21 project itself assumes an initial CO2 price of £40/t; and projects that with enough carbon production (and therefore economies of scale), CCS infrastructure could be economically viable with a carbon price as low as £10/t. For the purposes of our illustrative assessment, we have assumed a uniform carbon price of £25/t to 2050.

  A large-scale hydrogen switchover would entail substantial quantities of carbon which would utilise CCS infrastructure. The H21 project estimates that c. 1.5Mt pa of carbon will be produced to service annual hydrogen demand of 6,423 GWh per annum in Leeds. In scenario 3 there is 587 TWh hydrogen demand by 2050, which equates to around 137Mt CO_2 produced annually or 1,988 cumulatively by 2050. Exhibit 15 shows the profile of the annual and cumulative CO2 produced in scenario 3 (National Hydrogen).

Exhibit 15. Scenario 3 (National Hydrogen): cumulative and annual CO_2 sequestered



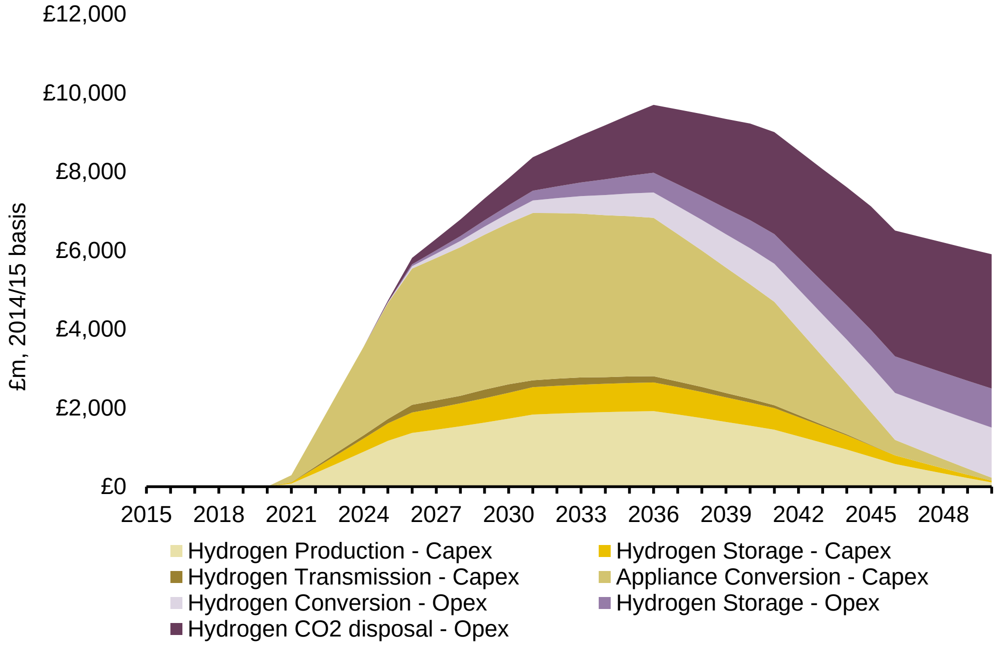
Source: Frontier Economics

58 As previously, on the basis of consumption of 6,453 GW for Leeds using DECC consumption data

Summary hydrogen switchover costs

Given the above analysis, the total new infrastructure and operating costs associated with a national hydrogen switchover is illustrated below. This is the annual cash outflow that would be required to meet the hydrogen demand projected in Scenario 3 – i.e. it does not reflect the expected profile of charges to customers (which would likely involve smoothing the recovery of capital costs over longer time horizons).

Exhibit 16. Possible evolution of hydrogen infrastructure costs in Scenario 3 (National Hydrogen)



Source: Frontier Economics and Aqua Consulting, based on data from H21 project.

Under these calculations, total costs for the hydrogen switchover from now to 2050 could total c. £209bn.

Of this, c. £127bn is capital investment – around £3.0bn of which is related to the hydrogen LTS network. By far the biggest source of capital expenditure is in the costs for converting appliances in homes, which totals £74.6bn by 2050.

By 2050 the annual estimated operating cost is in the region of £5.5bn, which under these assumptions would be the ongoing operating cost for hydrogen infrastructure.

As we discuss further in Section 6, one of the important questions for Government and Ofgem in a hydrogen scenario is the form of regulation and ownership of different parts of the supply chain. For the purpose of our analysis of network tariffs in Section 5, we have assumed that **only** the hydrogen LTS infrastructure capex is incorporated in network charges (i.e. the £3.0bn investment).

The other cost categories will flow through to customers in some form – either as part of wholesale costs or retail costs covered by the bill.

4.2 Network costs for each scenario

Our approach to projecting the network costs under each scenario begins by identifying the key cost categories for which Ofgem grants allowances to the networks under the RIIO price reviews. The categories we use are reinforcement; replacement; other capex; maintenance; and overheads.

In general, for each of these categories, we have taken Ofgem's cost allowances for the current RIIO price control periods from 2015 – 2021[59]; and rolled these forward to 2050 based on high-level assumptions about the drivers of these costs and how these will evolve in each scenario.

Where appropriate, we also apply a uniform efficiency improvement factor (or "productivity factor") to the cost forecasts, to reflect the expectation that unit cost efficiency will improve over time as technology evolves and economy-wide productivity improvements are realised. This assumption is drawn from the productivity assumption Ofgem has typically assumed in setting its price controls.

In addition to the more familiar cost categories, we have identified new cost categories which will reflect new network activity in each scenario. This includes (where relevant) decommissioning costs and investment in necessary hydrogen infrastructure. Our principle sources of information for these costs are industry expertise (in relation to decommissioning) and the outcomes of the H21 project (in relation to hydrogen infrastructure).

In this section we will illustrate the breakdown of costs for each scenario. Annex A sets out the main assumptions underlying these cost forecasts.

We note that these are cash costs (i.e. they have not been spread according to Ofgem's capitalisation assumptions). In Section 5 we go on to show how these costs would be converted to annual revenues for the network companies under the current model of regulation; and therefore the impact on tariffs of each scenario.

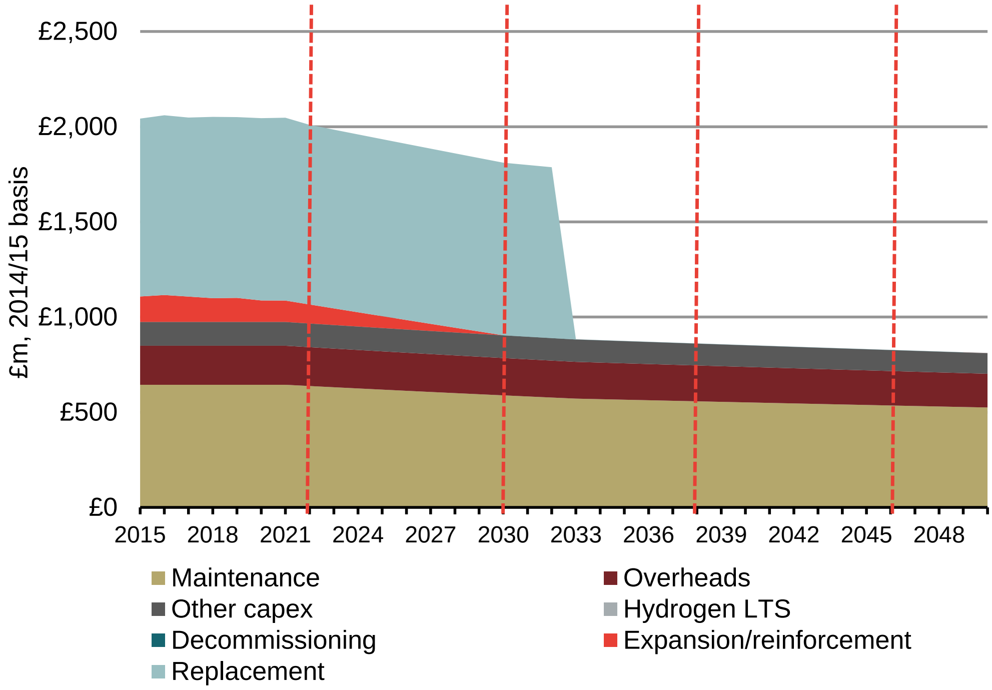
4.2.1 Scenario 1 (Central)

To re-cap, in the CCC's central scenario, the majority of the gas distribution network and gas transmission network is still needed to service the level of demand by 2050. We assume some decommissioning of the NTS network of 20% by 2050 to reflect that three out of the four NTS pipelines from St. Fergus will not be needed by 2050. This is a result of the changing gas flows as production from the North Sea is assumed to be declining.

Exhibit 17 shows the breakdown of costs for the distribution network.

[59] We do not account for 2014 costs because CCC scenarios start from 2015. Note that years are financial years – i.e. 2015 in this report should be read to mean financial year 2014/15.

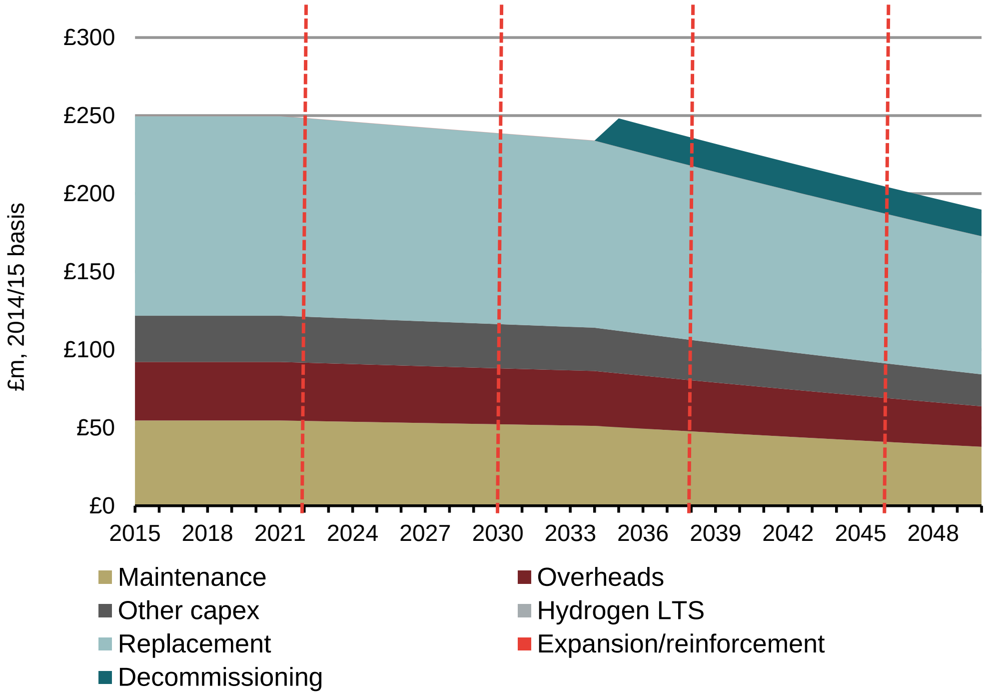
Exhibit 17. Scenario 1 (Central) – costs for the distribution network



After 2032, distribution costs are expected to fall by c. 57% relative to today's costs. This is predominantly driven by the end of the IMRP in 2032. To a lesser extent it is also driven by the assumption that the distribution networks would not invest in additional reinforcement costs after 2030, as a result of the expected decline in gas demand at that point.

Exhibit 18 shows the transmission network costs.

Exhibit 18. Scenario 1 (Central) – costs for the transmission network



Transmission network costs will also decline by 2050 in this scenario. This is driven by the assumption that overheads, maintenance, other capex and replacement costs vary by the network length. As we assume that the NTS will decommission 20% of its network, these costs also fall by a similar amount. The reduction in these costs is partly offset by the decommissioning costs that the NTS will need to incur.

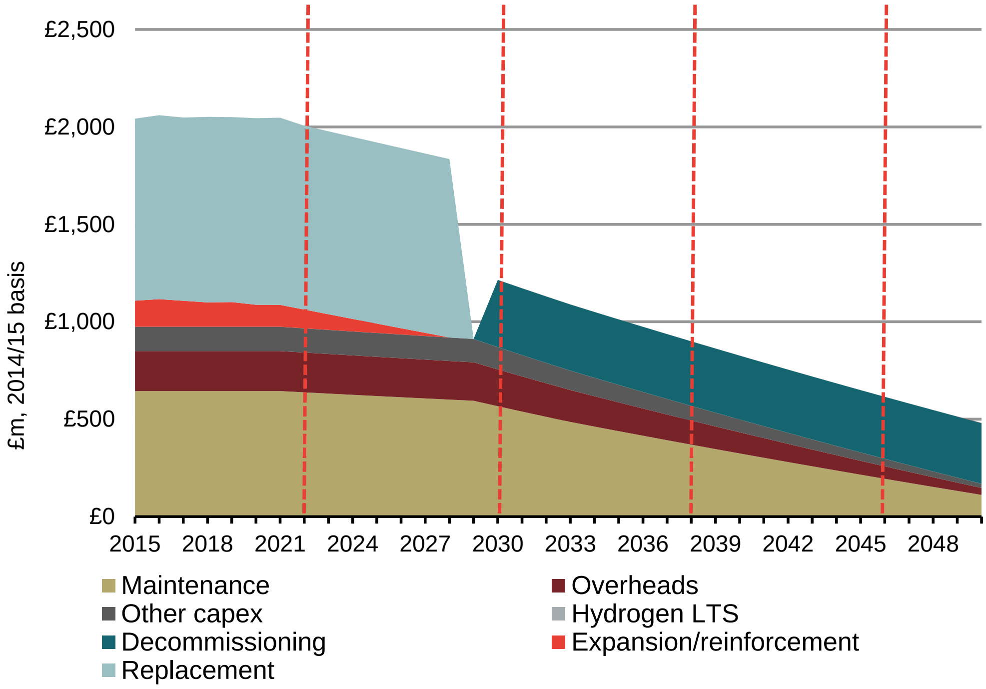
4.2.2 Scenario 2 (Low Gas)

The key differences in Scenario 2 versus Scenario 1 that drive cost differences are:

- first, in Scenario 2 we have assumed there is co-ordinated switching that enables the gas distribution and transmission networks to decommission larger parts of their networks; and
- second, Scenario 2 has a significantly steeper fall in gas demand, with minimal gas demand from buildings by 2050.

Exhibit 19 shows distribution network costs in this scenario.

Exhibit 19. Scenario 2 (Low Gas) – costs for the distribution network



This scenario is characterised by a significant portion of distribution networks being decommissioned. We assume 80% of the distribution network is decommissioned by 2050, commencing in 2030. This assumption is in line with the fall in demand by c.80% by 2050 and the assumption of co-ordinated switching, enabling localised grid decommissioning.

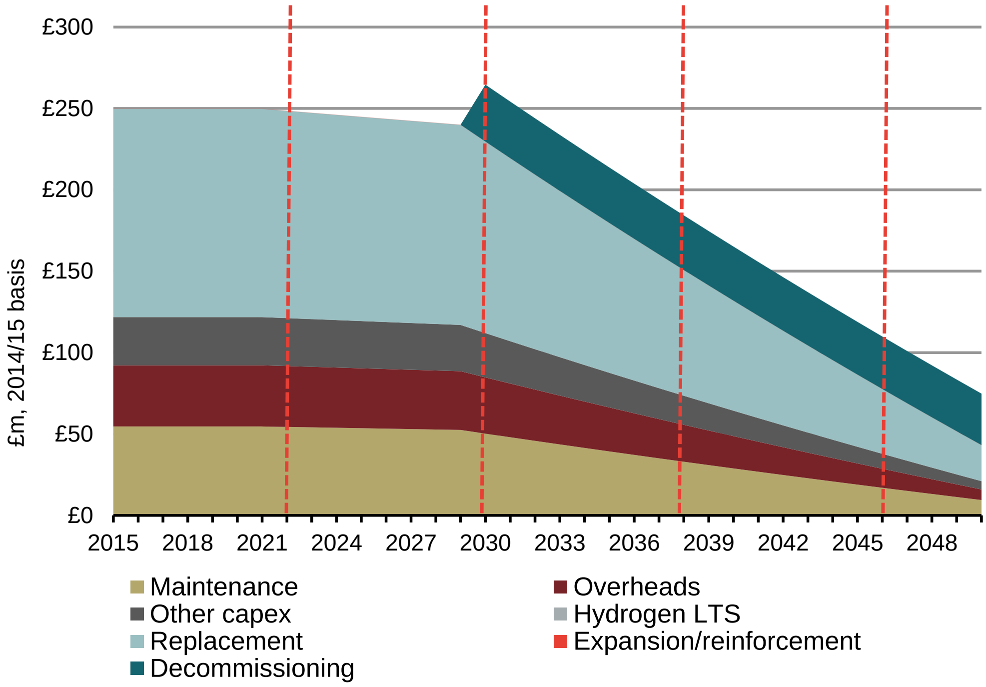
Maintenance, overhead and other capex costs for the distribution networks fall in line with the reduction in the networks length, since we have assumed that these costs vary by network length.

In anticipation of decommissioning commencing in 2030, reflecting falling gas demand, we assume investments in expanding the distribution network drop to zero by 2028 instead of 2030 in Scenario 1.

Similarly, given that parts of the distribution network are decommissioned, the IMRP is expected to end earlier, in 2028 versus 2032 in Scenario 1. We assume that network operators would anticipate decommissioning and, therefore, stop investing in replacing the network. This assumption depends on HSE co-operation in agreeing to end the IMRP four years earlier than anticipated, which is uncertain given the safety implications of such a decision.

Exhibit 20 shows transmission network costs.

Exhibit 20. Scenario 2 (Low Gas) – costs for the transmission network



For the NTS, we expect that a significant portion of the network is not needed to transport gas by 2050. However, we understand that there may be alternative uses to the NTS (including, for example, to act as an entry point for natural gas into the continent). Therefore, the extent to which National Grid could be expected to decommission its network, even in a world of low UK gas demand, is unclear.

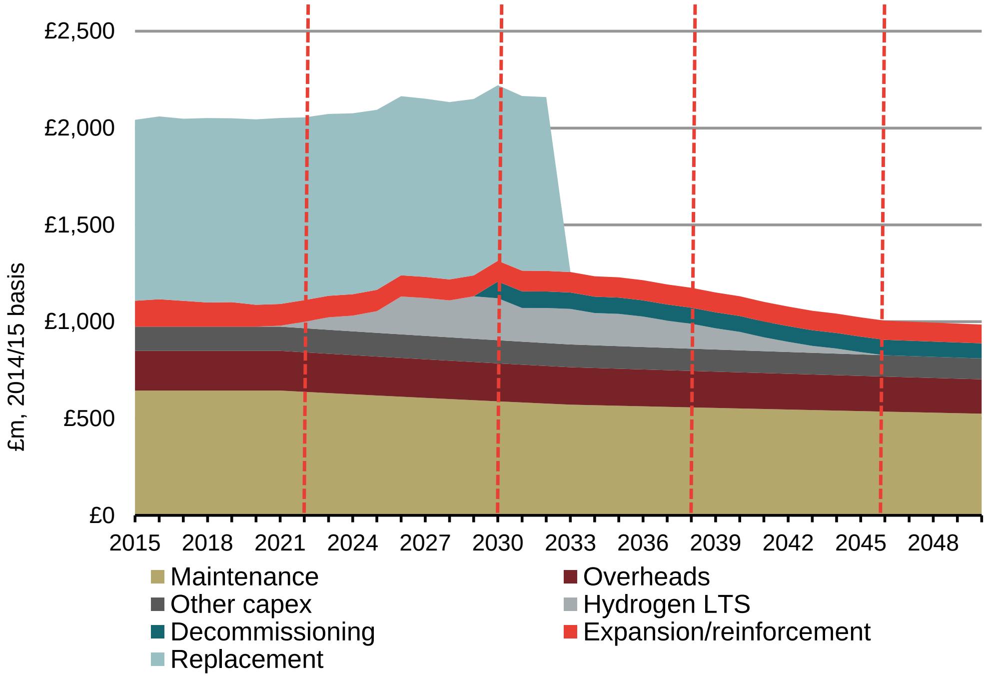
For simplicity, we assume 50% of the NTS is decommissioned. The NTS therefore retains its ability to export LNG via interconnector and supply limited industry and power generation demand.

However, in this world, we wouldn't expect UK domestic gas customers in general to continue to pay for parts of the network which are primarily being used to supply non-UK demand. Instead, these costs would be expected to be charged to shippers. We therefore assume that maintenance costs, overheads, replacement costs and other capex costs for the transmission network fall proportionately to an 80% reduction of network length.

4.2.3 Scenario 3 (National Hydrogen)

Scenario 3 assumes a national switchover to hydrogen. As explained above, for the purposes of capturing only network related costs, we include here only the costs associated with a new hydrogen LTS as part of the gas distribution network costs.

Exhibit 21. Scenario 3 (National Hydrogen) – costs for the distribution network



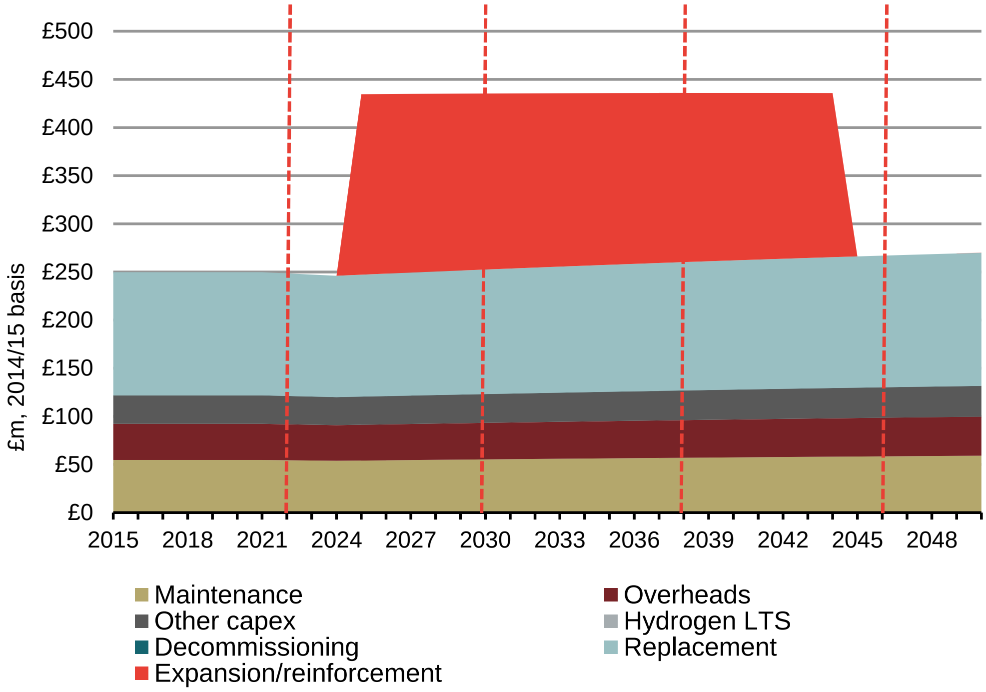
For the distribution network, we assume a lead time of 5 years (i.e. if a city is going to switch to hydrogen in 2025, it will start incurring hydrogen LTS costs in 2020). There are also some decommissioning costs after 2030 for the old LTS.

The HSE IMRP will ensure that the distribution network is suitable to transport hydrogen as the iron mains will be replaced with plastic mains. Therefore, we assume that the HSE Iron Mains programme continues until 2032, in line with Scenario 1.

We also assume that the distribution networks will need to continue incurring reinforcement costs in line with their RIIO-GD1 levels, incorporating an efficiency gain of 0.5% per annum.

All other distribution costs (maintenance, overheads, and other capex) are similar to Scenario 1.

Exhibit 22. Scenario 3 (National Hydrogen) – costs for the transmission network



For the transmission network, since methane supplied through the NTS is the assumed feedstock for hydrogen, and a large portion of energy is lost in converting methane to hydrogen, the NTS is likely to need to be able to transport more methane compared to the other scenarios.

We have assumed that 25% reinforcement expansion will be required to the NTS to accommodate the additional methane required in scenario 3. We anticipate this level of NTS reinforcement will be required to accommodate reconfiguration of the NTS to match the geographical locations of the hydrogen production hubs. However, this is still an area of uncertainty since the geographical demand profile of a full hydrogen switchover is yet unknown[60].

Our assumption drives the additional reinforcement investment illustrated above. We assume that reinforcement costs in expanding the transmission network's capacity by 25% is expected to take place over 20 years between 2025 and 2045 in line with the hydrogen switchover profile. Recent historical costs for NTS pipeline range from £1.8 million per kilometre to £2.3 million per kilometre. We assume a midpoint of £2 million per kilometre as the unit reinforcement cost, based on recent historical reinforcement costs.

In addition, we assume there is no NTS decommissioning in this Scenario, in contrast to Scenario 1 and Scenario 2.

All other transmission costs (maintenance, overheads, other capex and replacement) increase proportionately to the increase in the NTS capacity. We have also captured an on-going efficiency improvement on those costs over time.

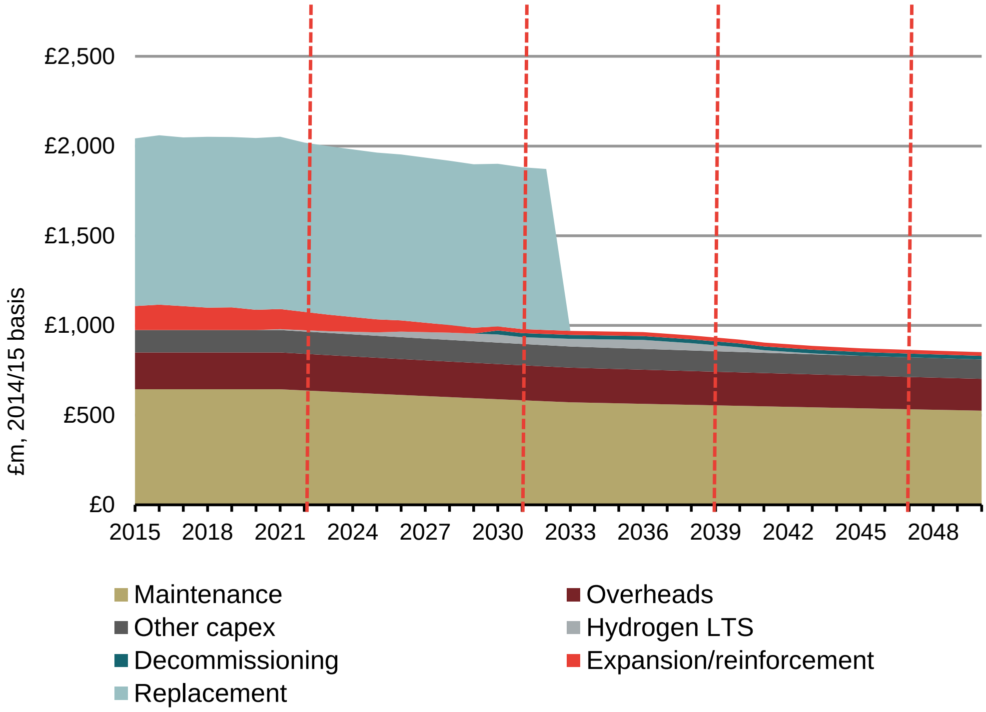
[60] We note, in particular, that SMR hydrogen production implies a different profile of demand through the NTS – at present there are daily peaks which the NTS must manage; while in a hydrogen scenario flows through the NTS are likely to be more constant (because SMR production facilities are most efficient when running non-stop).

4.2.4 Scenario 4 (Patchwork Hydrogen)

This scenario sees a regional switchover to hydrogen in the north of England.

Exhibit 23 show the costs for the distribution network.

Exhibit 23. Scenario 4 (Patchwork Hydrogen) – costs for the distribution network

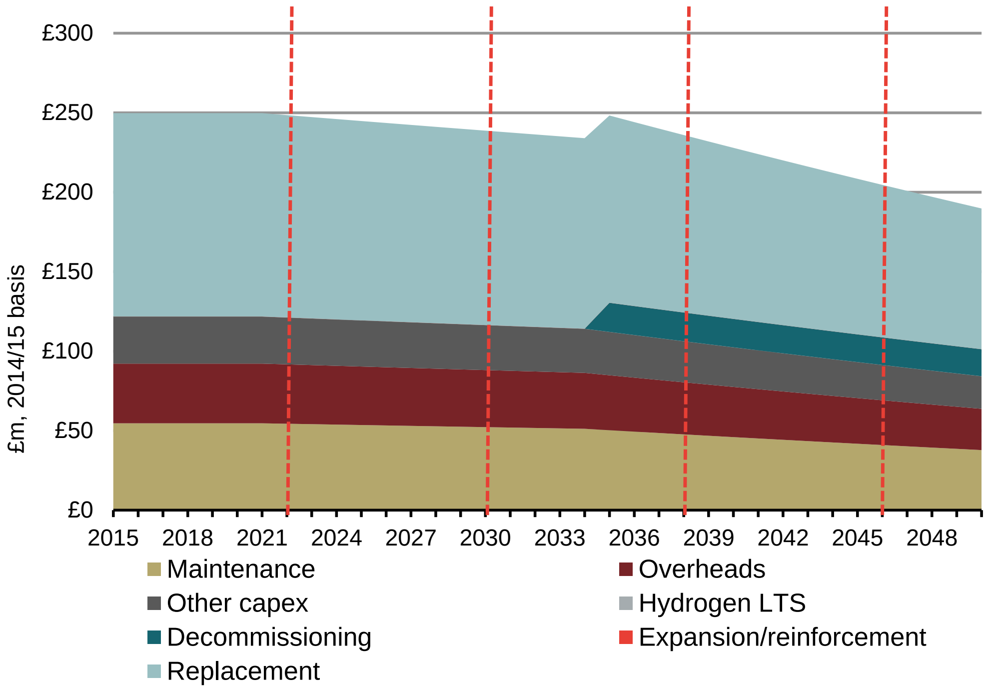


For the distribution network, non-hydrogen costs remain in line with Scenario 1 with the exception of reinforcement costs. Reinforcement is assumed to continue until 2040s for the areas that convert to hydrogen, as the hydrogen demand for these networks will remain at similar levels to today's gas demand.

The networks that switch to hydrogen will also incur the costs for constructing the hydrogen LTS and decommissioning the old LTS in those areas.

Exhibit 24 shows the transmission network costs. The transmission network cost implications are similar to Scenario 1.

Exhibit 24. Scenario 4 (Patchwork Hydrogen) – costs for the transmission network



5 IMPACT OF SCENARIOS ON NETWORK TARIFF AND ECONOMIC MODEL

As part of our assessment of whether the current regulatory framework is capable of managing decarbonisation trajectories, we have sought to understand the impact future demand scenarios could have on gas transmission and distribution tariffs.

To do this, we have developed a model which seeks to replicate all of the key features of Ofgem's current financial model for calculating revenue allowances for the gas networks. Our model converts the network cost forecasts (as described in Section 4) into allowed network revenues annually to 2050 – for example by smoothing the recovery of capital expenditure over a long time horizon.

From this we are able to derive information which is relevant to the question of regulatory reform to 2050, including:

- the impact on network tariffs and consumer gas bills, allowing us to draw implications about the potential impact on grid customers; and
- the impact on network revenue requirements and the evolution of the RAB, allowing us to evaluate how investors might perceive the implications of the scenarios.

We have not considered the price elasticity of demand for gas customers, and therefore we have not undertaken any dynamic assessment to understand whether the price rises observed in some scenarios would lead to additional switching away from gas. Our analysis instead provides high-level indication of the effects on network consumers and investors.

In this section, we describe the outputs of the analysis for each scenario and draw conclusions in relation to each. Annex B provides more detail on how we have constructed the economic model, setting out the assumptions we have made and the inputs we used.

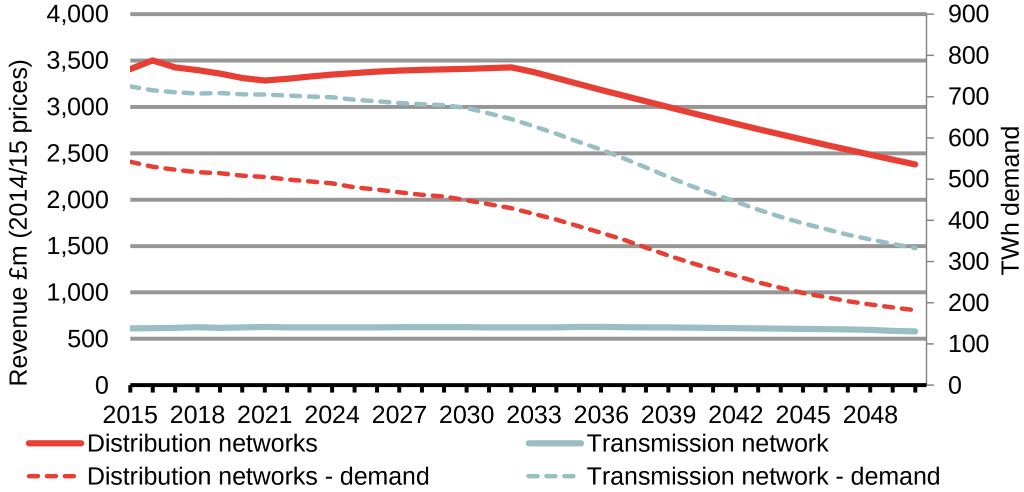
5.1 Scenario 1 (Central)

5.1.1 Description of results

Exhibit 25shows the revenue and demand profile to 2050 for gas distribution networks and the transmission network. The solid line is the revenue profile, while the dotted line is the demand profile[61]. The values for the distribution networks are shown at an aggregate across the GB networks, although our model allows for assessment at the individual network level.

[61] The CCC's Scenarios are based on total UK demand, which is inclusive of Northern Ireland. Since this report focusses on regulation of the GB networks by Ofgem, we have adjusted total UK demand to exclude demand in Northern Ireland.

Exhibit 25. Scenario 1 (Central): Revenue and demand profile to 2050



Source: Frontier Economics calculations

Total GDN revenues start to decline in the mid-2030s. This is driven primarily by:

- capital expenditure falling away after the IMRP programme ends in 2032;
- the depreciation allowance for pre-vesting assets falls over time as a result of the sum of digits depreciation profile applied by Ofgem[62]; and
- assumed productivity improvements result in (real) cost reductions over time, meaning revenue requirements also fall.

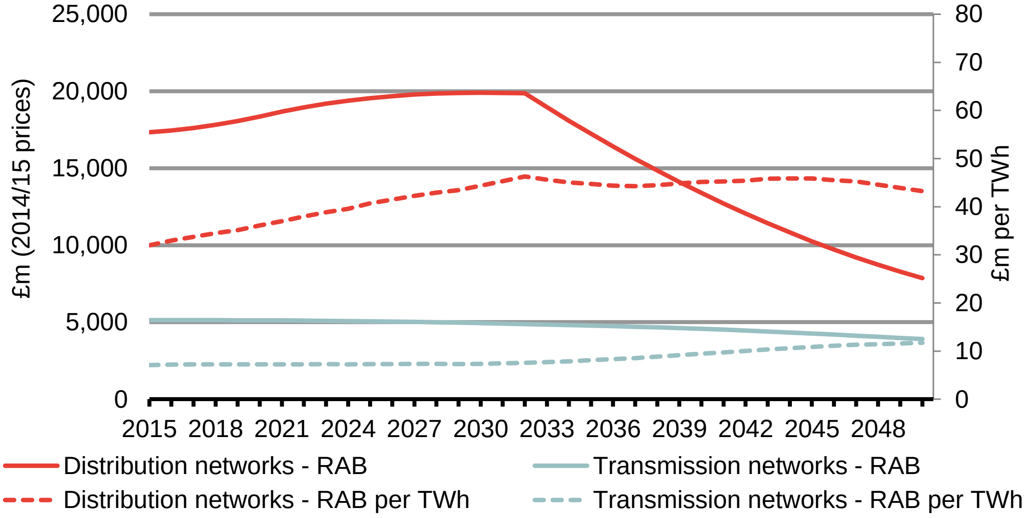
Transmission revenues also drop slightly over the period. This is driven by our productivity assumption, and because we assume that decommissioning results in lower maintenance, overheads, replacement and other capex costs.

Exhibit 26shows the RAB to 2050 (solid line). The total RAB gives an indication of investors' absolute exposure to the risk of not recovering their assets.

We also show the profile of RAB per TWh (dotted line). This gives a high-level indication of whether there is likely to be increased stranding risk – if RAB/TWh increases, this implies that a greater quantum of RAB must be recovered from a lower customer base, indicating that the recovery of that investment may be more at risk.

[62] Pre-vesting assets refers to the value of the network RAB at the time of privatisation (i.e. assets dating to pre- 2002), Ofgem set an asset life for pre-vesting assets of 56 years at the time of privatisation, and continues to use this today – meaning these assets will be fully depreciated by 2058. Ofgem uses a sum of digits depreciation profile, meaning depreciation is front-loaded.

Exhibit 26. Scenario 1 (Central): RAB and RAB per TWh profile to 2050



Source: Frontier Economics

For the GDNs:

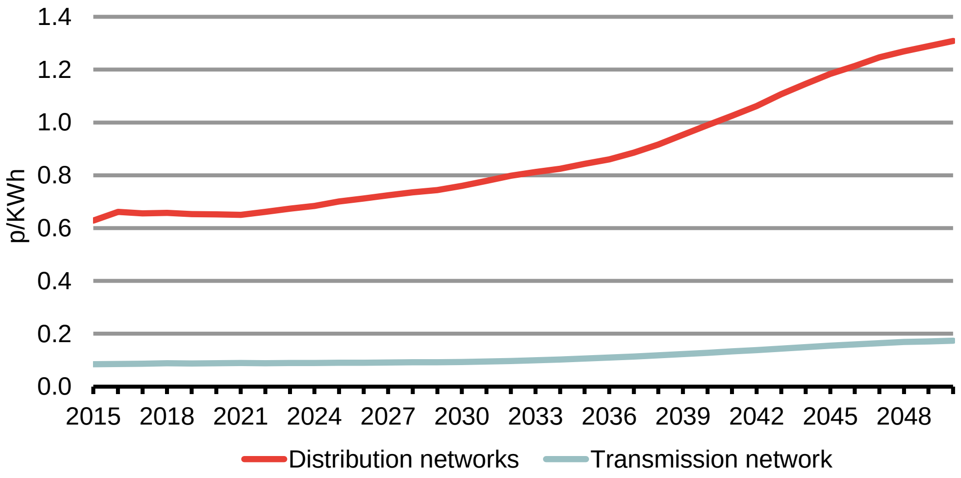
- The un-depreciated RAB for distribution assets by 2050 is projected to fall 55% to £8 billion from around £18 billion in 2017 in this scenario.
- The RAB per TWh for the distribution network increases by 28% from £34 million per TWh in 2017, to £43 million per TWh in 2050.

Similarly, the un-depreciated RAB for transmission assets by 2050 is projected to fall by 24% (from £5 billion in 2017 to £4 billion in 2050). The RAB per TWh for the transmission network increases from £7 million per TWh in 2015 to £12 million per TWh in 2050.

Our model calculates an aggregate network tariff by dividing the annual revenue requirements by the total volumes of electricity distributed[63]. The distribution and transmission tariff trajectory is shown in Exhibit 27.

[63] In reality, different network tariffs are set for different customers and a large component of network tariffs is capacity-based. However, our aggregate tariff calculation allows us to draw broad conclusions on the impact on tariffs in each scenario, and is consistent with the way the CCC has presented network tariffs elsewhere.

Exhibit 27. Scenario 1 (Central): Distribution and transmission tariffs



Source: Frontier Economics calculations

Network tariffs approximately double by 2050 in this scenario. Most of this increase arises after 2030, when the fall in gas demand starts to accelerate.

Since network costs are around 20% of the final customer gas bill[64], such changes would translate to a c.20% increase in final bills (other things remaining equal)[65]. The annual increase of gas bills implied by this scenario is 0.5%[66].

We assume that this scenario also sees customers switching to hybrid heat pumps by 2050[67]. These customers would see a smaller increase (c.6%) in their dual-fuel heating bill by 2050[68].

5.1.2 Conclusions

Network tariff increases in this scenario appear to be largely manageable in the context of long time-horizons and expected increases in unit heating costs, given decarbonisation targets. The increase happens reasonably steadily over a relatively long period of time, and may be further mitigated by increased energy efficiency over this period.

This scenario also does not result in particular concerns over the recoverability of RAB. Even though in this scenario total gas demand falls by 66% for the distribution network and 54% for the transmission network, the RAB also falls by

[64] DECC (2014), Estimated impacts of energy and climate change policies on energy prices and bills, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384404/Prices__Bills_report_2014.pdf, Table D1

[65] We have not calculated the impact of the change in gas demand on the remaining 80% of the gas bill. Instead we simply assume that the remaining 80% of the gas bill is made of variable costs. Relaxing that assumption will result in higher gas bill increases by 2050, compared to those we report here.

[66] This is calculated as a compounded annual growth rate over the period 2015-2050.

[67] The CCC's 5CB Central scenario does not include hybrid heat pumps, but the CCC notes that hybrids could be part of the future mix.

[68] We assume that only 30% of the hybrid heat pump's heat load is from a gas boiler. See Daikin, Hybrid Heat pump, http://www.daikin.co.uk/docs/ECPEN14-729_Daikin%20Altherma%20hybrid%20heat%20pump.pdf.

Our estimate of the impact of this scenario to customer's dual- fuel heating bill by 2050 only captures the impact of network tariffs on the gas part of the bill.

c.50% due to the limited requirement for new investment. Therefore, the measure of RAB per TWh stays relatively constant over time.

Given these two factors, the regulatory model is likely to largely be able to continue in its current form if Scenario 1 were to materialise.

One aspect that may warrant further consideration relates to how domestic customers will be charged for their use of gas. Network costs are predominantly driven by capacity and not throughput – at a system level, networks are configured to be able to meet peaks in demand. In Scenario 1, the CCC has asked us to assume that many customers switch to hybrid heat pumps – implying that their annual gas consumption would fall, but the network capacity requirements remain reasonably constant.

The networks' use-of-system charges to suppliers reflect the fact that capacity is an important driver of costs – most of these charges are calculated on a per-customer basis rather than a per-unit basis (with differentials across different customer types). However, suppliers are currently limited to charging final customers based on a combination of a standing charge and a per unit charge[69]. The licence includes a clause that would allow Ofgem to relax this requirement if it considered necessary; and Ofgem is reviewing tariff structures generally following the CMA's market review[70]. If hybrid heat pumps do become more prevalent in the longer term, Ofgem should at that time consider whether charging structures are sufficiently flexible to allow costs to be spread equitably over different types of customer.

5.2 Scenario 2 (Low Gas)

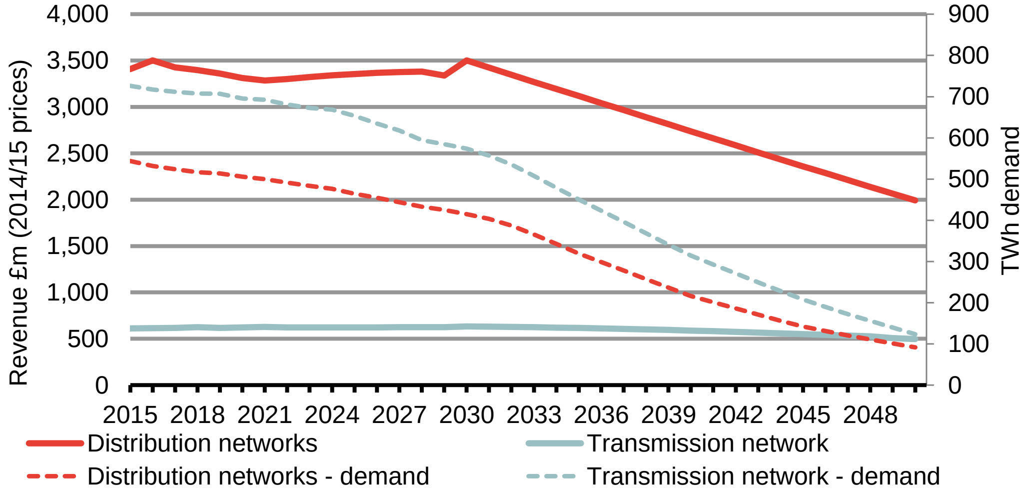
5.2.1 Description of results

The revenue and demand profile for this scenario is shown in Exhibit 28.

[69] Gas suppliers licence, Standard Condition 22A.

[70] The CMA recommended that Ofgem remove certain restrictions that were previously in place around the form of charging.

Exhibit 28. Scenario 2 (Low Gas): Revenue and demand profile to 2050



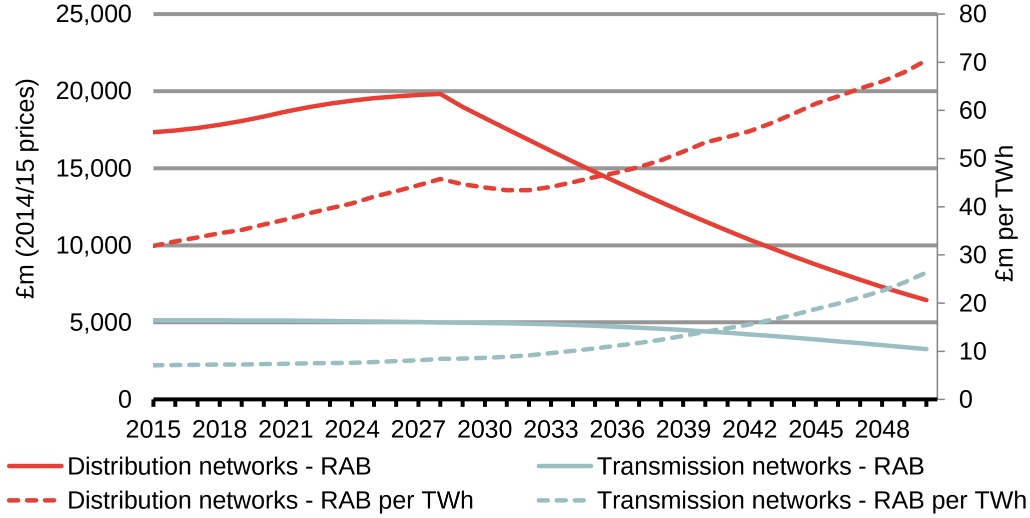
Source: Frontier Economics calculations

The revenue requirements of gas distribution and transmission networks are similar to Scenario 1 in the medium term, but are lower in the long term. This is primarily a result of our assumptions around decommissioning. Our assumptions result in a net benefit from decommissioning, as the savings on overheads, maintenance costs and other capex offset the direct decommissioning costs.

For the distribution networks there is a further reduction in revenues vs. Scenario 1 associated with our assumption that the IMRP programme would be ended earlier in Scenario 2 (i.e. in 2028 instead of 2032).

Exhibit 29shows the RAB and RAB per TWh profile for this scenario.

Exhibit 29. Scenario 2 (Low Gas): RAB and RAB per TWh profile to 2050



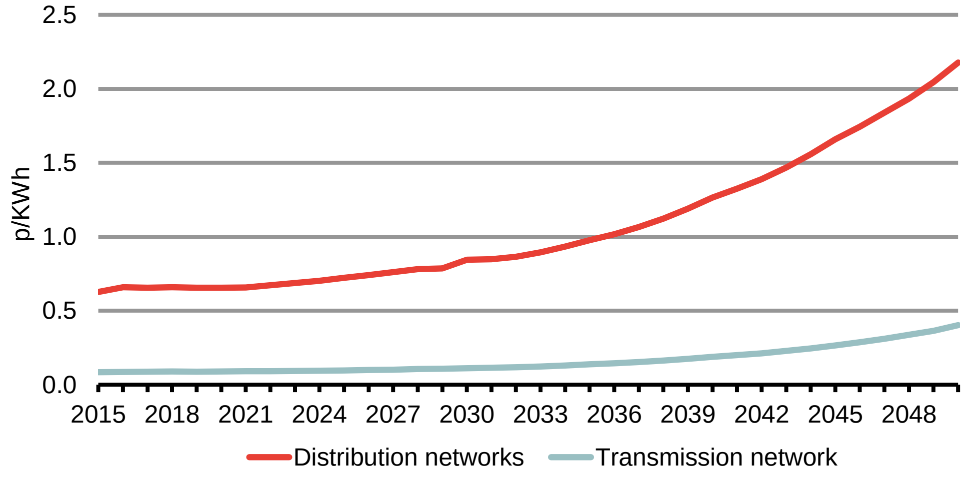
Source: Frontier Economics

The un-depreciated RAB for the combined distribution and transmission assets by 2050 is £9.7 billion. This is 57% lower than 2017, and £2.1 billion lower than in Scenario 1.

However, RAB per TWh increases materially for both the distribution and transmission networks. For the distribution network, RAB per TWh in Scenario 2 is £70 million in 2050 - 109% higher than 2017. For the transmission network, the RAB per TWh is £26 million in 2050 - 266% higher than 2017.

Distribution and transmission tariffs to 2050 are shown in Exhibit 30.

Exhibit 30. Scenario 2 (Low Gas): Distribution and transmission tariffs



Source: Frontier Economics calculations

Tariffs would increase by a factor of more than 3.6 in this scenario – a more material increase than in Scenario 1. This is driven by the more radical decline in gas demand we see in Scenario 2. This would translate into an increase of 50% to the average customer gas bill[71].

5.2.2 Conclusions

This scenario poses more serious regulatory challenges for Ofgem, compared to Scenario 1.

Despite a fall in investment, the increase in network charges would be expected to lead to increases in gas bills of more than 50% by 2050 (equivalent to an annual increase of 1.2%) in real terms. This increase is caused almost entirely by the large fall in gas demand, resulting from the assumption that there is no CCS in this scenario.

Although this might pose affordability questions, there will be a much smaller number of properties connected to the gas grid compared to today (given the 98% reduction in total demand for buildings between 2015 and 2050 assumed in this scenario). Although we have not conducted any price sensitivity analysis, it might be assumed that any customers remaining on the gas grid by that time will have simply chosen to accept the higher prices (although more significant social challenges would arise if the remaining customers have no alternative options).

The more significant consequence, however, relates to stranding risk. There is a material fall in gas volumes, but nearly £10bn of outstanding RAB to recover by

[71] Again we are assuming that 20% of the gas bill is network charges (see footnote 65).

2050 – raising the very real prospect that network investors would be unable to recover that outstanding investment.

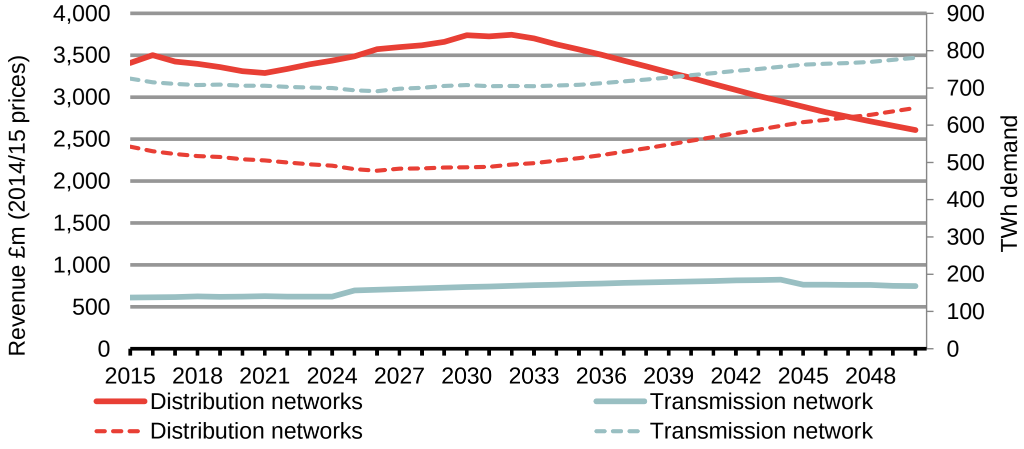
This sort of stranding risk has the potential to stymie investment (or raise the required cost of capital) now. We discuss the possible regulatory treatment of stranding risk more fully in our recommendations in Section 6.

5.3 Scenario 3 (National Hydrogen)

5.3.1 Description of results

The revenue and demand profile for this scenario are shown in Exhibit 31.

Exhibit 31. Scenario 3 (National Hydrogen): Revenue and demand profile to 2050



Source: Frontier Economics calculations

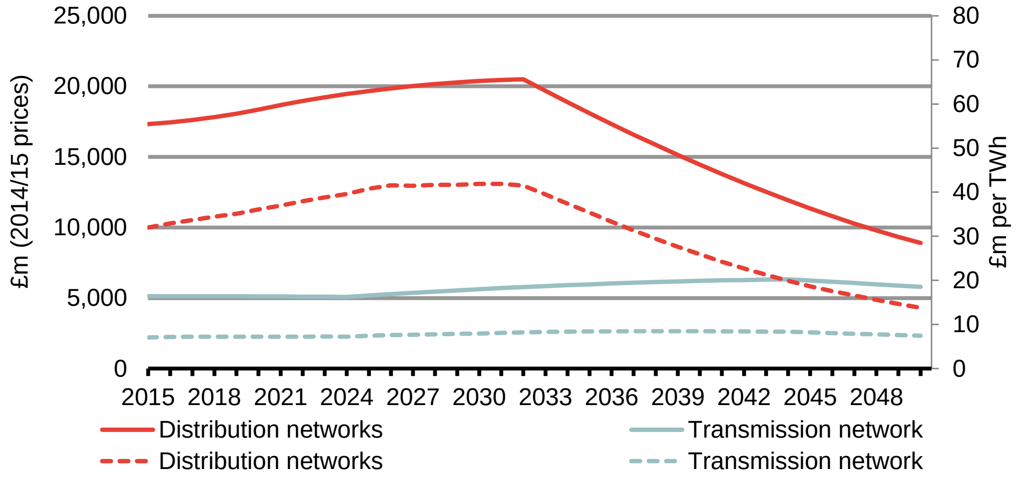
In this scenario, we assume that the revenues for the distribution networks will include new regulated costs associated with building the hydrogen LTS infrastructure. While this pushes costs up, revenue falls after 2030s driven by the end of the IMRP and fall in depreciation of pre-vesting assets, as it does in the other scenarios.

Annual revenue requirements of the NTS will also increase in the medium to long term, driven by network reinforcement requirements associated with transporting additional methane to produce hydrogen.

The combined gas and hydrogen demand by 2050 is materially higher than in Scenario 1 and Scenario 2.

In Exhibit 32 we show the RAB and RAB per TWh profile to 2050.

Exhibit 32. Scenario 3 (National Hydrogen): RAB and RAB per TWh profile to 2050

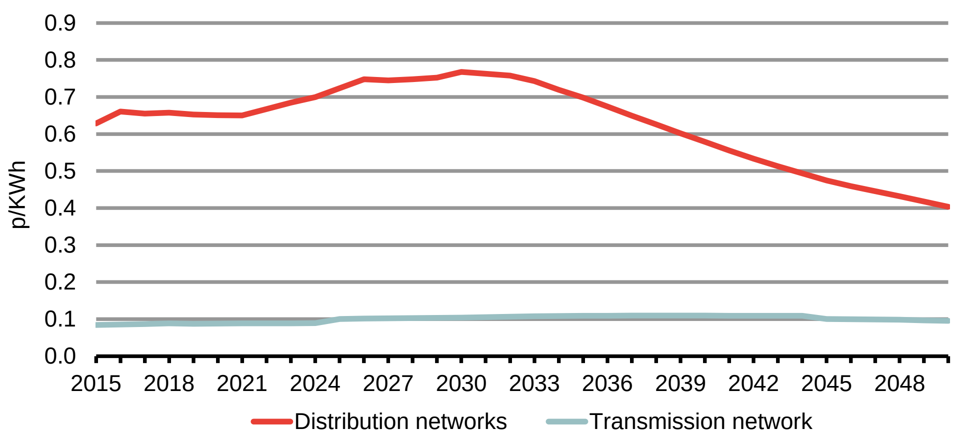


Source: Frontier Economics

The un-depreciated RAB for the combined distribution and transmission assets by 2050 is projected to be £15 billion, i.e. 35% lower than 2017. However, RAB per TWh falls by 59% to £14 million by 2050 for the distribution network; and £7 million by 2050 for the transmission network (similar to today's value).

The network tariff trajectory is shown in Exhibit 33.

Exhibit 33. Scenario 3 (National Hydrogen): Distribution and transmission tariffs



Source: Frontier Economics calculations

Network tariffs would increase slightly in the 2020s as a result of higher network revenue requirements. However, tariffs would fall in the longer term by around 30%, as a result of lower revenue requirements and higher gas/hydrogen demand.

5.3.2 Conclusions

Since stranding is not an issue in this scenario, we focus on the customer impact modelled. As explained, we have assumed that the only additional network costs are associated with the development of the LTS and NTS networks. While there are substantial other infrastructure costs (CCS, SMR plant, appliance conversion etc.), for the purposes of this report we have assumed these costs are not included in network charges.

The tariff results illustrate one of the potential benefits of a hydrogen scenario – that it would utilise network infrastructure which is already in place, and which customers have already been paying for. Since the IMRP programme ends in 2032, and depreciation of pre-vesting assets tails off, network charges would actually start to fall by 2030 under our current modelling assumptions.

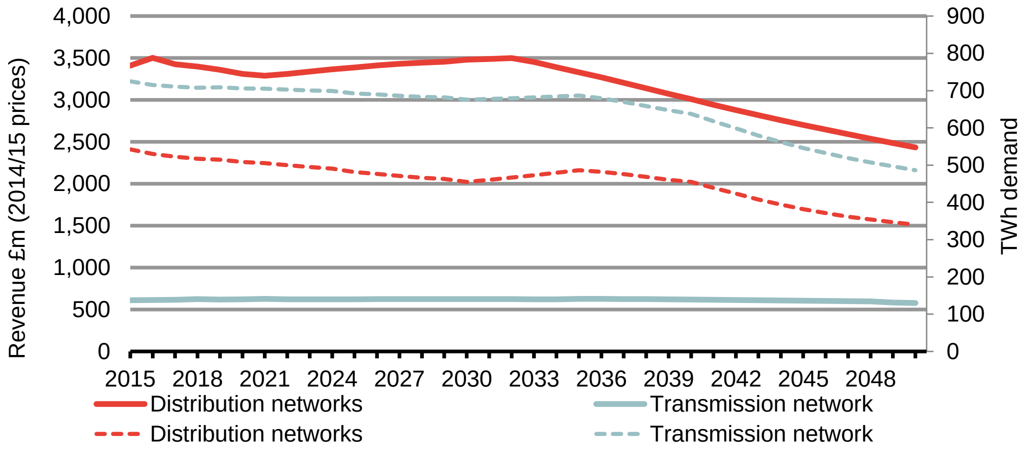
Our model is based on assuming Ofgem's current asset lives, depreciation and capitalisation rates remain as today. In reality, in a hydrogen scenario Ofgem would likely have the option of extending asset lives etc. so as to smooth the recovery of network investment over a longer time period (potentially more in line with the useful technical life of the assets). Such a change would have the effect of managing the hump in tariffs seen in the 2020s; and potentially driving further decreases in the network tariff over the period as a whole.

5.4 Scenario 4 (Patchwork Hydrogen)

5.4.1 Description of results

The revenue and demand profile for this scenario are shown in Exhibit 34.

Exhibit 34. Scenario 4 (Patchwork Hydrogen): Revenue and demand profile to 2050

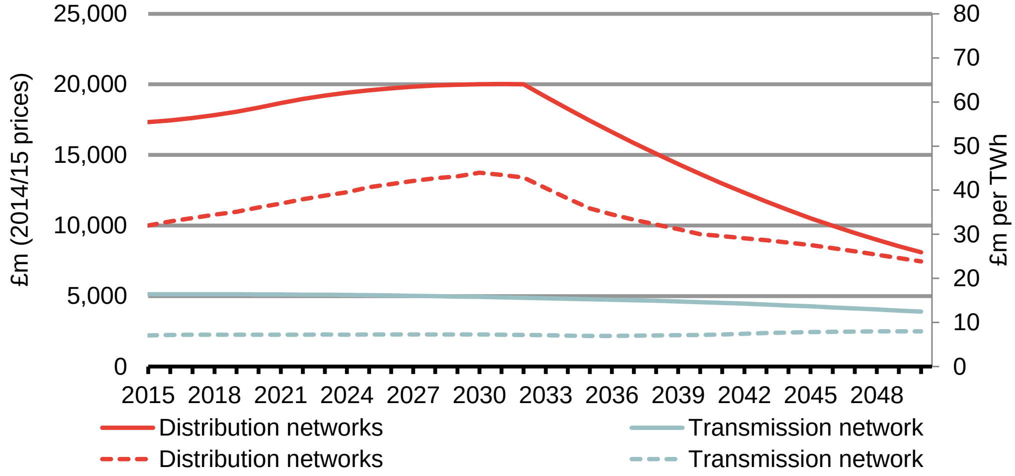


Source: Frontier Economics calculations

The revenue requirements for both the distribution and transmission networks are broadly in line with those in Scenario 1, particularly by 2050. There are some decommissioning costs and hydrogen LTS costs associated with the regional hydrogen switchover, but all other costs are similar to Scenario 1.

The RAB profile and RAB per TWh is shown in Exhibit 35.

Exhibit 35. Scenario 4 (Patchwork Hydrogen): RAB and RAB per TWh profile to 2050

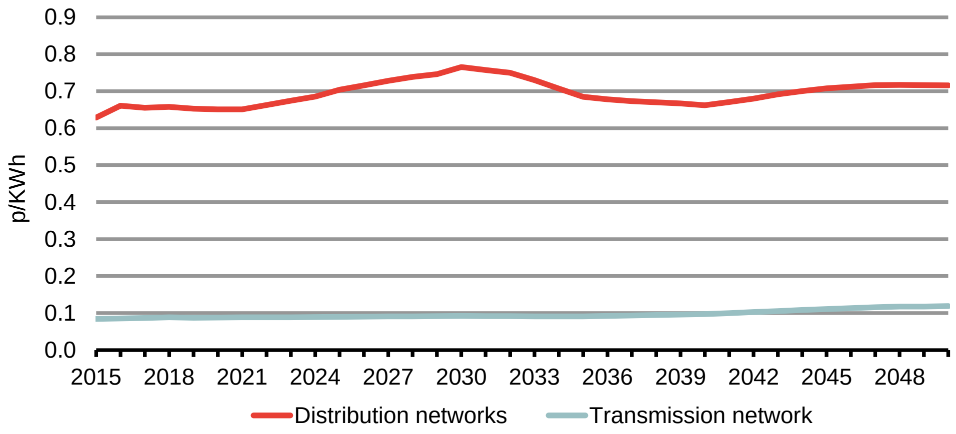


Source: Frontier Economics

Both the RAB and RAB per TWh fall by 2050 relative to today's levels. The un-depreciated RAB for the networks by 2050 is £12 billion.

The tariff trajectory is shown in Exhibit 36.

Exhibit 36. Scenario 4 (Patchwork Hydrogen): Distribution and transmission tariffs

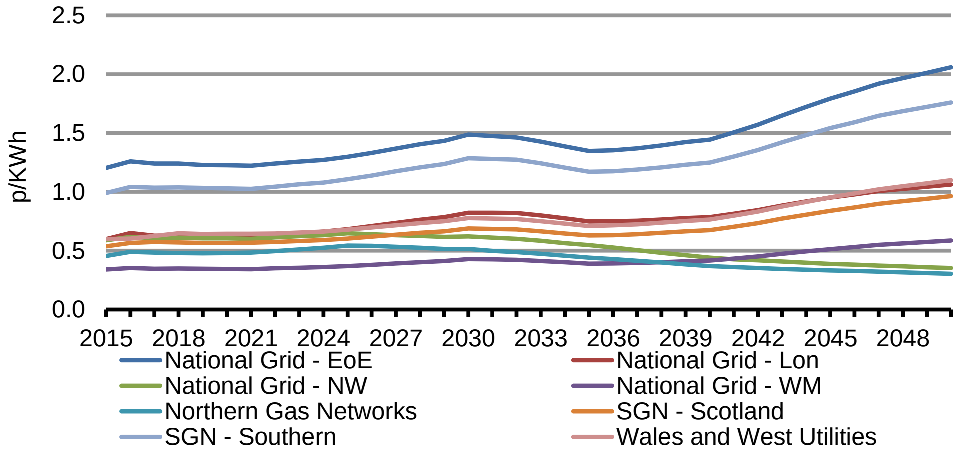


Source: Frontier Economics

Note: Chart does not highlight split between methane and hydrogen customers – i.e. assumes smoothing across all network customers.

A regional hydrogen roll out generates relatively static network tariffs if averaged across the country, as shown in the graph above, However, this masks differences between the regions that convert to hydrogen and those that remain on methane. In Exhibit 37 we show these regional differences in network tariffs. We have assumed that National Grid North West and the Northern Gas Networks are the two network areas where the hydrogen switchover occurs. The chart illustrates that network tariffs in those geographical regions would fall; while network tariffs elsewhere would be expected to rise.

Exhibit 37. Scenario 4: Regional differences in network tariffs



Source: Frontier Economics

Note: We assume that the majority of demand for National Grid – North West and Northern Gas networks switch to hydrogen.

5.4.2 Conclusions

A new issue arising from our modelling work for Scenario 4 relates to differences in network charges across regions of the country. Our analysis is limited, since it only focusses only on network charges (and the non-network hydrogen and methane costs would be expected to be very different). However, it illustrates one important issue in relation to any patchwork scenario – that customers in different regions of the country are likely to face different costs for achieving heat decarbonisation.

This raises questions of fairness and customer acceptance, which will need to be evaluated across all heating options. We discuss this further in Section 6.

5.5 Summary of modelling results

We summarise the modelling results in Exhibit 38 and Exhibit 39, for the distribution and transmission networks respectively.

Exhibit 38. Summary of modelling results – aggregated across distribution networks

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Allowed revenue (£ m)				
Start (=2017)	3,426	3,426	3,426	3,426
End (=2050)	2,381	1,994	2,608	2,434
% Change	-30%	-42%	-24%	-29%
Volumes (TWh)				
Start	522	524	523	523
End	182	92	646	340
% Change	-65%	-83%	24%	-35%
Implied network tariffs (p/KWh)				
Start	0.7	0.7	0.7	0.7
End	1.3	2.2	0.4	0.7
% Change	100%	233%	-38%	9%
Outstanding RAB (£ million)				
Start	17,609	17,609	17,609	17,609
End	7,860	6,444	8,900	8,108
% Change	-55%	-63%	-49%	-54%
RAB per TWh (£ million)				
Start	34	34	34	34
End	43	70	14	24
% Change	28%	109%	-59%	-29%

Source: Frontier Economics. For the gas distribution networks (GDNs), the figure shown is the aggregate change across all eight licensees.

Exhibit 39. Summary of modelling results – transmission network

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Allowed revenue (£ m)				
Start (=2017)	616	616	616	616
End (=2050)	579	496	747	579
% Change	-6%	-19%	21%	-6%
Volumes (TWh)				
Start	711	712	711	711
End	332	123	781	486
% Change	-53%	-83%	10%	-32%
Implied network tariffs (p/KWh)				
Start	0.1	0.1	0.1	0.1
End	0.2	0.4	0.1	0.1
% Change	101%	365%	11%	37%
Outstanding RAB (£ million)				
Start	5,134	5,134	5,134	5,134
End	3,901	3,255	5,800	3,901
% Change	-24%	-37%	13%	-24%
RAB per TWh (£ million)				
Start	7	7	7	7
End	12	26	7	8
% Change	62%	266%	3%	11%

Source: Frontier Economics. For the gas distribution networks (GDNs), the figure shown is the aggregate change across all eight licensees.

6 CONCLUSIONS & RECOMMENDATIONS

Our overarching objective is to identify policy recommendations related to the gas networks that will facilitate the achievement of decarbonisation objectives. In this section we therefore evaluate the regulatory and institutional challenges for gas networks in light of the scenarios described in the previous sections. To identify a set of policy recommendations for BEIS and Ofgem, we have drawn together our work covering:

- an assessment of issues in the current stakeholder environment, and drivers of outcomes arising from the network regulation framework (Section 2);
- an understanding of the main network characteristics and costs under each scenario (Sections 3 and 4); and
- an indication of the likely change in network tariffs and the risks to investors in each scenario (Section 5).

Based on these inputs, we have identified policy recommendations which can be grouped under three headings:

- Key immediate recommendations for Government policy;
- Low-regrets actions[72] for Ofgem at GD2/T2; and
- Medium term requirements for policy and regulation.

We discuss each group of policy recommendations in turn. We then conclude this chapter by setting out a timeline for Government and regulatory policy into the 2020s.

6.1 Key immediate recommendations for Government policy

At present, a wide number of scenarios could feasibly materialise. The degree of uncertainty over future network usage is stark, for example:

- if Scenario 2 materialises, there will need to be widespread decommissioning of gas networks and managed reduction in the size of these businesses; while
- if Scenario 3 materialises, the existing networks' role will become more central to achieving climate policy. There would be a need for incremental network investment[73], and there could even be a case for re-considering the network companies' role in the energy market.

This poses a problem for network regulation since the scenarios entail materially different network usage profiles. This has consequences for the activity that can and should be undertaken by Ofgem and network companies – for example,

[72] A low regrets options is one that is based on expected implementation cost and whether it allows for options to remain open.

[73] There would also be substantial additional investment in the non-network parts of the hydrogen value chain.

there is little point investing significant effort in modifying network codes to facilitate a hydrogen switchover if a hydrogen scenario is unlikely to materialise.

We have therefore identified three policy recommendations, which could be developed within the next few years, and would serve to reduce uncertainty, thereby enabling Ofgem and others to develop the regulatory framework appropriately.

- **Recommendation 1:** Government will need to make certain policy decisions that determine the direction of heat decarbonisation.
- **Recommendation 2:** Government should establish a clear framework within which to make those decisions.
- **Recommendation 3:** A significant programme of research must be implemented and funded now, to enable those decisions to be made on an informed basis.

We discuss each in turn.

6.1.1 R1: Government will need to make policy decisions that will determine the direction of heat decarbonisation.

A clear outcome from our analysis is that achieving wide-scale heat decarbonisation will only be possible if Government makes certain key decisions to determine the way in which heat will be decarbonised.

This will be particularly important when customer choice is being limited. This is most evident in any hydrogen scenario. Based on current expectations, we would expect that Government would need to mandate a switchover to hydrogen, for the following reasons.

- In practice, the existing network infrastructure cannot be used to supply both hydrogen and natural gas simultaneously. Depending on the local network configuration, large groups of customers will therefore need to be switched off natural gas and on to hydrogen simultaneously. It would therefore not be possible for individual consumers to retain a choice over whether and when to switch – if some customers were allowed to choose to switch to hydrogen while others within the same area chose to remain on gas, this would imply that two sets of parallel network infrastructure would need to be in place, which would be highly inefficient.
- It is possible that a model could be developed under which customers could exercise a form of collective decision making. For example, customers in a given area or region could collectively decide whether to switch to hydrogen or to stay on methane. For example, regional or local referendums could be run to pose the question for each Local Authority area, or groups of areas. Or Local Authorities could decide on behalf of customers. The challenge with this sort of model is that an efficient roll-out of hydrogen infrastructure is likely to be dependent on achieving a particular scale of demand (which may not be achieved if this 'regional choice' model were used). Further, switching decisions in one area are likely to affect the costs to customers in neighbouring areas. We therefore expect that the sequencing and co-

ordination challenges of this sort of decision-making model would be extremely challenging and expensive.

- Even if these local decision-making challenges can be overcome, switching to hydrogen is likely to entail higher costs to customers (at least initially) relative to remaining on methane - particularly if domestic gas consumption continues not to incur carbon charges. Given the findings from various studies of customer behaviour in relation to switching, customers may be unable to make informed switching decisions in the face of high upfront costs.
- Finally, it is worth recognising the sheer scale of the challenge of decarbonising heat. Providence Energy calculates that, in a hydrogen scenario, 20,000 properties would need to be switched off methane and onto hydrogen each and every week for over 20 years, in order to achieve a national switchover[74].

As a result, we consider that Government will need to make a strategic decision to mandate a hydrogen switchover. Government has previously made similar decisions, such as in relation to the smart meter roll-out; or the roll-out of superfast broadband[75]. Valuable lessons could also be derived from processes of conversion from high calorific gas to low calorific gas in Europe[76].

Similar strategic decisions are also likely to be required for the non-hydrogen scenarios. The issues around the scale and speed of customer switching are not unique to hydrogen. The challenges associated with relying on the market to deliver that sort of customer switching behaviour are clear - solutions may have to be sub-optimal at an individual property or regional level, in order to gain system wide benefits and achieve decarbonisation targets.

Unless Government is committed to making these strategic decisions, the credibility of certain decarbonisation scenarios (and particularly hydrogen) will be diminished. This has the potential to undermine the ability of industry, Ofgem, and other stakeholders to undertake the necessary planning and research required to deliver decarbonisation - including the need to develop appropriate network regulation.

Assessment

- **High importance, likely to be contentious:** Regulatory policy to-date has focussed on allowing markets to decide. Achieving consensus on the need for such decisions (or alternatively, clarity on role for market-driven results) will be important.
- **Responsibility:** BEIS
- **Timing:** Major strategic decisions to be made by 2025-27.

[74] Imperial College Centre for Energy Policy and Technology (ICEPT), Managing Heat System Decarbonisation, Comparing the impacts and costs of transitions in heat infrastructure, April 2016. http://provpol.com/wp-content/uploads/2016/05/Heat-infrastructure-paper.pdf, page 7.

[75] See details on Government policy here: https://www.gov.uk/guidance/broadband-delivery-uk , and updates here: https://www.gov.uk/government/policies/broadband-investment

[76] e.g. Belgium and Germany.

6.1.2 R2: Government should establish a clear framework for decision-making by 2020.

A significant source of risk to the achievement of any decarbonisation scenario is the current lack of clarity surrounding decision-making. Institutional arrangements must be designed to ensure that relevant decision-makers know what decisions need to be made, by which body, and by when – and joined-up thinking will be required across these areas[77].

BEIS should therefore identify what decisions need to be made over the next 5-10 years to facilitate delivery of decarbonisation scenarios; the timeline of such decisions; and the role different stakeholders should play in making those decisions - in particular, identifying who is ultimately responsible.

This should include setting out the roles and responsibilities of Ofgem; devolved Governments; Local Authorities; industry; other Government Departments and BEIS itself. Crucially, BEIS should also identify how best to engage customers (or their representatives) in the decision making process, particularly where the solution involves removing individual customer choice.

The processes that are put in place must be capable of delivering the scale of decisions required in the available timeframes: this ability to deliver timely decision-making is something generally thought to be lacking in current industry processes[78].

Assessment

- **Low-regrets:** Early action needed to achieve any scenario.
- **Responsibility:** BEIS
- **Timing:** 2017-18.

6.1.3 R3: A significant programme of research must be implemented and funded now, to enable informed decisions to be made in the 2020s.

Given the set of decisions that will need to be made, a programme of further research will be required to ensure those decisions are well-informed.

This begs two further questions.

- **Question 1:** What are the right questions to be asked as part of the low-carbon heating research programme – and who should be answering them?
- **Question 2:** How much funding for this research is needed, and where will it come from?

[77] We note that the ETI's "Enabling Efficient Networks" programme sets out views on what is needed for good governance of decision making in this environment.

[78] We understand that this is something the IET is looking at, following on from its Future Power System Architecture (FPSA) project.

Identifying a set of questions for further research

There are a number of important strategic questions for Government that require further examination, most notably:

- Will there be a role for CCS in the UK's future energy mix?
- Will hydrogen be economically and technically feasible?
- How can the electricity system manage the extreme seasonal swings in demand that will be required with the electrification of heating?
- What is the role and scope for other forms of heat decarbonisation?

To a large extent, these decisions are intertwined. The question of whether a hydrogen switchover will represent the best option for the UK will depend (among other things) on the viability and availability of CCS infrastructure; and the potential costs associated with alternative forms of decarbonisation (both of heating and of other sectors in the economy). The CCC asked us to identify knowledge gaps for a hydrogen scenario, which we show in the boxes below on CCS and hydrogen.

As part of this research, there is likely to be a central role for pilot tests/demonstrators of different models and technologies. This research would not only improve understanding of the costs, but also of customer behaviour aspects and acceptance of different forms of roll-out.

THE ROLE FOR CCS INFRASTRUCTURE

The network usage profiles in Scenarios 1, 3 and 4 are all dependent on the development of a UK CCS infrastructure. Accordingly, the viability of CCS will determine the likely issues that gas network regulation will need to address.

The CCC's hydrogen scenarios project that hydrogen demand would start to appear by 2025[79]. But assuming that hydrogen is produced with SMR technology, there would be no point in turning on the hydrogen tap until CCS is available. Indeed, given the 25% efficiency losses in SMR hydrogen production, emissions would rise if hydrogen replaced methane before CCS was available.

Investment in hydrogen production and transportation infrastructure will therefore not be forthcoming if investors do not have a high degree of certainty that CCS infrastructure is economically and technically viable; and will be in place within timeframes that enable carbon targets to be met. The question, therefore, is how and when will uncertainty over CCS be resolved?

Carbon pricing is currently insufficient to provide incentives for private investment in CCS – partly because the current carbon price is likely to be too low; and because even if carbon prices were higher, there is material political uncertainty that continues to surround long term carbon prices. In addition, the technical viability of large-scale CCS technology is as-yet unproven, and accordingly the costs that would actually be associated with developing CCS infrastructure are still uncertain. There is also uncertainty about just how much CCS demand there could be in the UK – see Exhibit 15 for the potential in scenario 3.

The combination of these factors means investors are unlikely to bring forward CCS investment unilaterally – the stranding risk associated with sunk CCS investment is currently too great. In these circumstances, Government would need to bear a large part of the risks relating to initial CO_2 infrastructure development in order for CCS to go ahead. Government will therefore need to set out whether funding and support for trialling and research into CCS will become available in future, and provide sufficient commitment that it will be delivered.

Identifying the source and scale of funding

There is currently funding available to undertake this research: from the Network Innovation schemes administered by Ofgem, as well as more general innovation funding from Government.[80] Whether this will be sufficient (particularly in light of the cancelation of the CCS competition and any loss of European funding) and will be targeted to schemes of greatest value is something that will have to be kept under review.

79 The NAO recently reviewed the impact of withdrawing funding for CCS. It stated that DECC estimates cancelling the competition has removed the option of CCS contributing meaningfully to decarbonisation before 2030. https://www.nao.org.uk/wp-content/uploads/2016/07/Sustainability-in-the-Spending-Review.pdf . The Government has recently stated that it views CCS as having a potentially important role to play in the long-term decarbonisation of the UK's economy; and that it is looking at options for the next steps for CCS in the UK. http://www.publications.parliament.uk/pa/cm201617/cmselect/cmenergy/497/49704.htm#_idTextAnchor006

80 This is both funding from central Government, such as DECC's innovation programme which has promised funding of £500 million over 5 years, as well as funding from the Devolved administrations (such as the Scottish Government's Local Energy Challenge Fund).

Ofgem is currently evaluating its innovation funding and the CCC should consider the conclusions when they become available. As well as ensuring that the level of future funding is not diminished, the CCC may also want to follow-up on the following points.

- **Cross-vector funding.** A number of the questions that will be relevant to improving understanding of the future use of the gas network will require innovation outside of the gas networks themselves. If the benefits to the trialling lie outside of the networks, Ofgem's current funding criteria would make it difficult for such schemes to be funded, even though the results of the trials may be in the interests of gas network customers. Since Ofgem's NIC and NIA schemes are such a large part of the available funds, there is a question whether the innovation funding is being directed where it could be of most value.
- **Stage of innovation.** Ofgem has chosen to focus funding on projects at high Technical Readiness Levels (TRLs) that, in addition, may be expected to deliver customer benefits in the near term. Since the question of future use of the network is one that stretches over a long timeframe, there is a question whether such a focus is appropriate.

In addition, some innovation and research could and should be funded directly by industry itself, since existing players have an interest in putting a case forward for different alternatives.

<u>Assessment</u>

- **Risks involved, but action essential:** Significant challenge associated with co-ordinating research programmes and targeting funding to most effective areas/projects. Scale of funding requirement unclear. Should seek to avoid distortions caused by vested interests.
- **Responsibility:** BEIS
- **Timing:** 2017-20.

KEY RESEARCH QUESTIONS FOR A HYDROGEN SCENARIO

The H21 research project is the first available study into the technical viability of hydrogen for providing fuel for home heating. The project has identified a set of future research projects, and a timeline for these which could enable BEIS to be in a position to make a strategic decision on hydrogen by the early 2020s.

The following areas of research are likely to be central to understanding the technical and economic potential for hydrogen in the UK.

- **Safety**: The H21 project has concluded that hydrogen can be transported safely utilising existing network infrastructure. However, industry standards and codes will need to be developed governing minimum safety requirements; and further active trialling and demonstration will be needed[81].
- **System costs and configuration:** The 'unit' costs for many parts of the hydrogen supply chain (e.g. SMR, LTS infrastructure, appliance conversion[82] etc.) are reasonably well known. However, there is limited understanding of how a national (or regional) hydrogen system would be configured. For example, an evaluation needs to be undertaken of: CCS capacity and location; optimal sizing and location of SMR plants and storage capacity; and configuration of the LTS (e.g. whether to link multiple SMR sources to each city/town etc). Identifying the optimum configuration across these components of a hydrogen infrastructure will require system-wide planning, since the costs are co-dependent (e.g. a given set-up for SMR plants will have implications for the required CCS infrastructure and LTS length).
- **Customer acceptance**: A variety of sources of disruption are likely to occur in the event of a hydrogen switchover. For example, there would be a short period during which neither hydrogen nor natural gas would be available to switching customers, as the existing network is purged of natural gas and made safe for hydrogen. The H21 project concludes that this would be limited to a period of one or two days, but it could vary across customers. Similarly there will need to be activity within homes as boilers, cookers and other methane-burning appliances are converted to be hydrogen-compatible.

  All of these factors could lead to customer dissatisfaction or resistance to further roll-out. The near-term research programme should seek to trial and demonstrate ways in which communication with customers can effectively mitigate this risk; and identify efficient and effective conversion processes to minimise disruption. It is likely that significant public information campaigns will be needed in the run-up to any switchover.
- **Product development:** At present there are no large-scale providers of burners or home appliances which are hydrogen-ready. The boiler and cooker manufacturing industry will need to be ready for hydrogen switchover, and may need to undertake its own R&D programme.

[81] The Institution of Gas Engineers and Managers has said it will help in developing standards for the construction and testing of hydrogen gas distribution systems and safety. http://www.igem.org.uk/media/232929/Hydrogen-Report-Complete-web.pdf

[82] See, for example, the method employed in Dodds and Demoullin, *"Conversion of the UK gas system to transport hydrogen"*, March 2013.

Exhibit 40. Summary of key immediate recommendations for Government policy

Policy	Low-regrets / areas of contention	Responsibility	Timing
R1: Policy decisions to determine direction of heat decarbonisation	High importance, likely to be contentious	BEIS	2025-27
R2: Establish framework for decision-making	Low-regrets	BEIS	2017-18
R3: Implement & fund significant programme of research	Risks involved, but action essential	BEIS	2017-20

Source: Frontier Economics

6.2 Low-regrets options for Ofgem at GD2/T2

The upcoming RIIO reviews are expected to be launched in December 2018, and concluded by December 2020. It is unlikely that key strategic Government decisions - which will have a material impact on the requirement for UK network infrastructure - will be made before this review is completed.

As a consequence, in the near term regulation should seek to ensure that the options across scenarios remain as open as possible and will not result in detrimental outcomes in future given the variety of potential scenarios.

The following set of policy recommendations are likely to be “low-regrets” actions which could be implemented by Ofgem at RIIO-GD2/T2. We consider these recommendations would strike a balance between keeping options open and reducing potential barriers to achieving any of the scenarios.

- **Recommendation 4:** Identify a clear approach to allocating stranding risk between customers and companies.
- **Recommendation 5:** Introduce appropriate uncertainty mechanisms to the RIIO controls that will allow re-openers at relevant trigger points.
- **Recommendation 6:** Develop understanding of decommissioning costs and approach to regulating these costs.
- **Recommendation 7:** Review of the current connections regime.
- **Recommendation 8:** Targeting gas network stakeholder engagement during business planning.

6.2.1 R4: Identify a clear approach to allocating stranding risk between customers and companies

For investors in network infrastructure, stranding risk is likely to be an important issue at the upcoming regulatory reviews, given the uncertainty around future gas scenarios. The prospect of asset stranding in the future has the potential to stymie investment now – depending on whether investors perceive this risk to be material; and whether they are adequately compensated for the risks they bear. The treatment of stranding risk must therefore be considered carefully in the context of needing to keep options open - since some scenarios will require ongoing investment and possibly even expansion of the gas networks.

Normally, regulators seek to allocate risks to the party who is best able to manage or mitigate that risk. This may be with the network investors, for example if they are able to influence the utilisation of their assets. However, there are also likely to be some scenarios in which the network companies will have limited ability to manage stranding risk – for example, in a hypothetical scenario where Government mandated mass switching away from gas to alternative electric heating sources. Similarly, in some cases the networks will be asked (or even legally mandated) to undertake investments[83] which they will only recover over a long time period under the current regulatory model[84]. In these instances, the networks' ability to make a commercial investment decision (taking account of stranding risk) is constrained – i.e. they might be forced to make investment decisions which they would not otherwise have made, given the stranding risk.

Such situations could mean a higher cost of capital is required to finance investment, if this stranding risk is left with network investors. Alternatively, if the network companies have limited ability to manage the risk, Ofgem could implement measures to transfer some or all of this stranding risk to customers. This could be achieved by, for example, accelerating the recovery of investment through changes to the depreciation profile, asset life, and/or capitalisation rate. Other options for transferring stranding risk would likely require changes to legislation, including:

- transferring (part or all of) the gas network RAB to electricity networks, to be recovered from electricity customers;
- introducing new charges to energy customer bills (similar to "Public Service Obligation" charges); or
- government guarantees that any stranded assets resulting from Government policy will be funded (potentially by the taxpayer).

There are therefore a number of steps that Ofgem could do in GD2 and T2 to manage issues of asset stranding.

- First, Ofgem will have to assess a number of future plausible scenarios. Indeed, this is what Ofgem did in 2010 as a prelude to setting GD1 and T1 where it undertook a detailed assessment of the impact of various long-term scenarios for gas consumption on network tariffs[85].
- Second, Ofgem will need to decide whether the stranding risk should best sit with customers, companies or spread across both. If Ofgem thinks that the companies are best placed to manage the risk of declining gas demand, Ofgem should consider whether the WACC needs any adjustments to reflect how that risk is evolving, so that investment in regulated sectors continues.
- Alternatively, if it is felt that the companies cannot manage the risk, or the cost of them doing so via a change to the WACC is excessive, the alternative options for its recovery should be investigated.

[83] For example, the ongoing Iron Mains Replacement Programme is legally mandated through the Health and Safety Executive (HSE). Similarly Ofgem may requires companies to undertake a particular network reinforcement investment, or to target a certain number of fuel poor connections.

[84] At present, the recovery of investment is spread over 45 years.

[85] CEPA (December 2010), The economic lives of energy network assets, a report for Ofgem

Ultimately, Ofgem should seek to make clear its policy on asset stranding, including identifying:

- the circumstances in which investors would bear stranding risk vs. when investors would be protected; and
- the vehicle by which any protection from stranding risk could be expected to arise.

Ofgem's allowed cost of capital must then be consistent with its conclusions and policy around how stranding risk is allocated. Clear policy positions on these issues will allow investors to better understand the risks they are being asked to bear.

Assessment

- **Low regrets:** Addressing stranding risk with clarity over allocation of risks will be beneficial for investors and customers.
- **Responsibility:** Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

6.2.2 R5: Introduce appropriate uncertainty mechanisms to the RIIO controls that will allow re-openers at relevant trigger points.

It is unlikely that any of the strategic decisions outlined above will have been made in sufficient time for their impact on GDNs to be considered in the upcoming price reviews. However, the decisions could have consequences for the required network investment – potentially entailing some new costs that would need to be incurred within the period (e.g. to construct a hydrogen LTS, or to decommission parts of the network).

We do not expect that Ofgem will be able to establish a set of cost allowances at the price control review which could cover both eventualities. As a result, Ofgem will need to consider how to appropriately design uncertainty mechanisms that will ensure the timing of the RIIO price reviews does not result in undue delays to action that could be required to meet the emerging scenarios.

Ofgem's RIIO Handbook sets out the different forms that uncertainty mechanisms can take and identifies the type of circumstances in which uncertainty mechanisms could be employed. At a high-level, Ofgem could have two options:

- Ofgem could link cost allowances mechanistically to a particular cost driver – for example by setting an allowance for a unit cost per km of hydrogen LTS network constructed - and then evaluate in real time within the price review (or at the end of the review) what the efficient length of installed hydrogen-LTS would be.
- Ofgem could establish up-front a particular trigger event (or fixed points in time during the review period) at which point Ofgem could re-open the price control and assess whether its cost allowances and incentives reflect the network requirements.

In either case, the detailed design and specifics of any uncertainty mechanism should be established up-front, so as not to undermine incentives during the first part of the price control period. A well-designed uncertainty mechanism would have the effect of ensuring that regulation is sufficiently flexible to respond to developments in technology and Government policy during the price control period.

Assessment

- **Low regrets:** Uncertainty mechanisms are familiar and well-understood means to allow for flexibility in reg. model in the face of uncertainty.
- **Responsibility:** Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

6.2.3 R6: Develop understanding of decommissioning costs and approach to regulating these.

It is likely that under any scenario, there will need to be some network decommissioning. In scenario 2 there is a prospect that up to 80% of the grid could be decommissioned.

Networks do currently undertake some decommissioning – such as steel services or gas holders that are no longer needed[86]. In addition, as part of the IMRP the networks have been undertaking a programme of replacing iron mains with polyethylene pipes.

The networks should therefore be familiar with decommissioning processes, and indeed have been developing innovative and efficient ways of doing this for the IMRP[87]. Ofgem has also set targets in the form of "secondary deliverables" for the number of steel services decommissioned; and for network risk reduced as part of IMRP through decommissioning.

However, the challenge implied by the type of decommissioning envisaged in the CCC's decarbonisation scenarios (and in particular in scenario 2) is different. Decommissioning undertaken to-date has largely been in the context of replacing assets which will continue to be used by customers for the supply of methane; or taking isolated parts of the network infrastructure out of service. In scenario 2, we envisage a situation where large parts of the network (e.g. entire cities or regions) are removed from natural gas altogether – meaning the whole network infrastructure would be redundant.

The scenarios therefore raise two issues for consideration:

- first, there is currently significant uncertainty around the potential costs and benefits of decommissioning large parts of the network; and
- second, there is currently no established regulatory approach to wide-scale decommissioning.

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[86] See, for example: http://www.northerngasnetworks.co.uk/2014/02/newcastle-gas-holder-to-be-decommissioned/

[87] See, for example, Ofgem's 2014-15 Annual Report: https://www.ofgem.gov.uk/system/files/docs/2016/03/riio-gd1_annual_report_2014-15_final.pdf

We discuss each in turn below. Overall we recommend that Ofgem should investigate both of these questions thoroughly at the RIIO-GD2 review.

Reducing uncertainty around the level of decommissioning costs

The uncertainty about the potential costs of decommissioning large parts of the network is driven primarily by the fact that a number of different options exist for how decommissioning could occur.

Some stakeholders have suggested that the network could simply be “switched off” and left in the ground without any gas throughput – although we understand that this approach could cause safety and technical issues which would make it infeasible. Other options include purging the networks; grout-filling pipes; or removing networks entirely from the ground. The range of cost uncertainty across these options is likely to be wide.

The uncertainty is exacerbated by the following factors:

- At present, it is not clear whether there would be any HSE-driven obligations to decommission redundant parts of the network in a particular way, to ensure they are safe.
- The most efficient decommissioning procedure may vary from location to location. The feasibility and implications of achieving decommissioning in any given local area is likely to depend on the network configuration at that location.
- There is uncertainty around the option value to investors of not decommissioning the assets but instead re-purposing them for possible alternative uses.
- For the purposes of our modelling, we have made some simplifying assumptions around the net effect of decommissioning – i.e. that reductions in costs for maintenance, overheads etc. will more than offset the direct costs of decommissioning the network. In reality, there is an open question around whether these net aggregate cost reductions would actually arise, since the link between other cost categories and network length is not as linear or simplistic as the assumption we have used for the purposes of the present analysis.

Further research on costs and understanding of requirements is therefore needed. The networks have informed us that network configuration in any particular area is a key consideration – i.e. to understand the impact of decommissioning any particular part of the network on flows elsewhere in the remaining network.

Ofgem could instruct the GDNs and NTS to prepare a decommissioning strategy and cost estimates as part of their well-justified business plans for RIIO-GD2/T2, which are expected to be submitted to Ofgem in summer 2019. To do this, Ofgem would need to set out the requirements for this in its Strategy decision (expected March 2019). Once received, the strategies could then be compared against each other to identify efficient approaches and best practice. Ofgem could also commission its own independent expert review; and potentially seek information around decommissioning costs from other countries.

As part of this, Ofgem should evaluate whether decommissioning will or will not lead to net cost reductions overall. Understanding the net benefits of decommissioning will be important for evaluating the overall costs to customers of switching to alternative technologies.

In addition, Ofgem should also open a dialogue with the HSE as part of the GD2/T2 review to identify whether there are safety implications of wide-scale decommissioning, and restrictions that would likely be imposed by the HSE.

Developing a regulatory approach to decommissioning costs

Subject to obtaining a better understanding of decommissioning costs, Ofgem will also need to consider the appropriate regulatory treatment of those costs.

As noted above, decommissioning to-date has generally been undertaken in the context of ongoing usage of the gas network. This has meant that it was a reasonable and fair solution to smooth decommissioning costs across all network customers.

In the future (and particularly in scenario 2) the driver of decommissioning is that customers are leaving the network. This raises a question about who should appropriately bear the cost of decommissioning.

- Arguably, the disconnecting group of customers are the direct cause of any decommissioning costs, and should therefore be charged directly for disconnecting. This is a similar rationale to charging connecting customers directly for any costs they impose as a result of connecting to the grid. However, there is no clear mechanism in place governing how networks could charge customers who are no longer connected to their network. Some form of charging methodology could be developed, but this would take time and engagement with industry and stakeholders.
- There may also be a social case for spreading decommissioning costs differently. For example:
  - Ofgem could effectively ask current customers to bear decommissioning costs on behalf of future customers, for example by establishing a “decommissioning fund” which could be generated through charges on network customer bills, starting in the GD2/T2 period.
  - Ofgem and BEIS could consider whether there is a social case for taxpayers to fund or subsidise decommissioning costs.
  - Ofgem could spread decommissioning costs across remaining network customers after the decommissioning has occurred.
- Finally, Ofgem may consider that network shareholders should bear directly some of the costs of decommissioning, on the grounds of this being a risk that shareholders should bear as a consequence of falling demand. The challenge of this approach is that it is likely to lead to difficulties in networks being able to finance these decommissioning activities; and would undermine the networks’ incentive to participate. We therefore expect that this is unlikely to be the appropriate solution.

Of course, to the extent that there are any benefits arising from decommissioning the network (e.g. net cost reductions; or value accruing as a result of a sale of the assets for alternative uses) the regulatory framework should also specify how such benefits would be allocated.

The discussion above sets out some initial views, but the economic rationale and incentive consequences for allocating the costs of decommissioning should be considered further. We expect that this discussion will need to take place as part of the GD2/T2 reviews, both because some of the potential regulatory options would involve changes to tariffs in these reviews; and because we expect it will be important for investors have early clarity on how any decommissioning costs will be funded (even if decommissioning is only expected to ramp-up in earnest at the subsequent regulatory period).

Assessment

- **Low regrets, but consider in context of priorities:** Decommissioning could be a significant issue in future, but this is not yet certain. Ofgem should get the balance right between investing time at the current review in this issue vs. focussing on alternative issues.
- **Responsibility:** Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

6.2.4 R7: Review of the current connections framework

The connections framework and incentives on GDNs to connect customers could be reviewed in GD1. Two policies could be considered.

Review of the FPNE scheme targets in light of decarbonisation objectives

As part of Ofgem's Fuel Poor Network Extensions (FPNE) scheme, Ofgem sets targets for the number of fuel poor customers which the GDNs must connect to the gas networks. The GDNs currently have a target to connect over 91,000 fuel-poor customers in the period 2013-2020. This scheme is premised on the idea that a gas connection is likely to represent an effective way to reduce fuel poverty.

There is a trade-off here between actively encouraging the GDNs to pursue new connections; and reducing barriers to future decarbonisation scenarios where gas use will need to decline. Arguably, if either Scenario 1 or 2 is likely to materialise, it is counter-productive from the perspective of decarbonisation objectives to continue to connect fuel poor customers. While the number of customers affected may not be large, the fact they are fuel poor makes any potential stranding of their investment following a gas switch-off particularly sensitive.

On the other hand, the scheme has so far been successful in helping to alleviate fuel poverty concerns; and curbing the scheme or reducing the targets would (at least in the short term) be detrimental to the objective of reducing fuel poverty.

In addition, given that any hydrogen scenarios will make use of existing network infrastructure, it may in fact be beneficial to the decarbonisation objectives for the GDNs to actively pursue more connections.

We recommend that Ofgem considers these issues more closely at the RIIO-GD2 review, and evaluates the appropriate trade-off between targeting more connections to alleviate fuel poverty; vs. the risk of locking more customers in to gas over the longer term. It is likely that Ofgem will need to consult with customer representatives; government; and industry to address this question.

Assessment

- **Low-regret option:** Keeping FPNE under review will in any case be on Ofgem's radar.
- **Responsibility:** Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

Extension of FPNE-type connections obligation to all connection requests

The Fuel-Poor Network Extensions programme requires the networks to provide an evaluation of the cost of alternative heat sources to all fuel-poor customers requesting a connection. A similar obligation on GDNs could be considered for all new connections requests. For example, if a developer for a new housing estate or block of flats applies for a gas connection, the GDN could be required to notify the relevant Local Authority and initiate an assessment of the viability and cost of low carbon district heating as an alternative. Similarly the GDNs could be required to provide the customer information on the cost of a heat pump as an alternative to the requested gas connection.

Although these policies may not lead to alternative switching decisions in the near term, there would likely be useful learning for network companies associated with implementing such reforms early on – for example, in developing best practice in communicating choices to customers; or in developing relationships with Local Authorities and providers of alternative heat sources.

These types of incentives could be incorporated under Ofgem's "Connections" output category within the RIIO framework. For example, Ofgem could provide discretionary rewards to companies which demonstrate or develop best practice in undertaking this activity. Ofgem could also ensure that knowledge is shared across the GDNs.

Before implementing this, however, Ofgem should assess how effective the extension to the FPNE scheme has been, and whether customers have found this information useful (or whether it has materially affected their choices). The benefits and learning arising from the FPNE scheme should be evaluated to inform a decision as to whether it is worthwhile to roll the policy out more widely. .

Assessment

- **Low-regret option, subject to evaluation of existing scheme:** Evaluation of effectiveness under FPNE scheme needed, cost to implement would need to be assessed.

- **Responsibility:** Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

6.2.5 R8: Incentives for more targeted stakeholder engagement

As part of developing well-justified business plans, Ofgem currently requires the network companies to demonstrate that a variety of stakeholders have been involved in the development of those investment plans. At the first round of RIIO price reviews, Ofgem noted that these incentives had been effective in improving the quality and effectiveness of stakeholder engagement by the networks. There are two areas where this could be enhanced or more specifically targeted, namely:

- Engagement with Local Authorities; and
- Cross-vector co-ordination between networks.

Engagement with Local Authorities

We expect that it will be important for the GDNs to engage with Local Authorities in their respective network areas to understand any plans for heat zoning or other developments in the network areas. Any targets or policy proposals for district heating in the local area should have an effect on the business planning assumptions for the GDNs.

To facilitate this, BEIS may wish to consider a temporary increase in funding available to Local Authorities via the Heat Networks Delivery Unit[88], in recognition of the timing of the price review and the fact that this is a key staging post in the gas networks' investment planning.

Ofgem may also wish to consider whether incentives can be improved for encouraging ongoing co-ordination between the GDNs and Local Authorities during the price control period itself.

Assessment

- **Low-regret option:** Enhanced co-operation between GDNs and Local Authorities is unlikely to incur material additional costs, but could prove valuable for ensuring consistent planning.
- **Responsibility:** Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

Cross-vector co-ordination between networks

An issue which was highlighted to us in the course of our stakeholder interviews for this project is that greater co-operation between different network companies is likely to be needed in future. In particular, given that some decarbonisation scenarios involve significant switching from gas to electricity, it will be counter-productive if the assumptions underpinning gas distribution network plans are

88 The Heat Networks Delivery Unit (HNDU) provides grant funding and guidance from commercial and technical specialists to Local Authorities

inconsistent with the assumptions underpinning electricity distribution network plans. At the very least this could lead to inefficient cost allowances (since both sets of companies arguing separately are likely to make the case for higher allowances).

Ofgem could therefore require that evidence of an assessment of trade-offs between gas and electricity network investments is demonstrated within the GDN business plans. This could be set out as part of Ofgem's evaluation of business plans for the purpose of fast-tracking.

Similar requirements could also be developed for co-operation between the GDNs and the NTS.

One potential downside to this policy (in particular in relation to co-operation between the GDNs and NTS) is that the network companies are legally unbundled. Any co-ordination incentives should seek to avoid situations where the network companies are able to utilise co-operation opportunities to achieve commercial advantage at the expense of customers.

Assessment

- **Low-regret option:** Subject to caveat around avoiding any cross-network co-ordination resulting in rent-seeking behaviour.
- **Responsibility**: Ofgem
- **Timing:** 2018-20. To be considered as part of GD2 review.

Exhibit 41. Summary of low-regrets options for Ofgem at GD2/T2

Policy	Low-regrets / areas of contention	Responsibility	Timing
R4: Identify approach to allocating stranding risk	Low regrets	Ofgem	2018-20 - as part of GD2 review.
R5: Introduce uncertainty mechanisms for GD2/T2	Low regrets	Ofgem	2018-20 - as part of GD2 review.
R6: Evaluate decommissioning costs and reg. approach	Low regrets, but consider in context of priorities	Ofgem	2018-20 - as part of GD2 review.
R7: Review connections regime	Low regrets, subject to evaluation of existing schemes.	Ofgem	2018-20 - as part of GD2 review.
R8: Stakeholder engagement	Low regrets	Ofgem	2018-20 - as part of GD2 review.

Source: Frontier Economics

6.3 Medium term requirements for policy and regulation.

The requirements for policy and regulation into the 2020s will depend, in part, on the outcomes of the RIIO reviews and the research programmes and policy proposals set out above. Broadly speaking, the main issues can be split between scenarios involving a hydrogen switchover, and non-hydrogen scenarios (although there is some crossover between these).

In the event that the Government decides to proceed with a mandated hydrogen switchover, a number of steps would automatically follow.

- **Recommendation 9:** Government and Ofgem to adapt industry standards/network codes, and Ofgem's duties.
- **Recommendation 10:** Ofgem to establish the market and regulatory arrangements required for the provision of hydrogen.
- **Recommendation 11:** Government to consider how best to protect consumer interests in the event of a switchover.
- **Recommendation 12:** Government to decide on geographical coverage of any hydrogen switchover.

Alternatively, in the event that a hydrogen switchover is not mandated, a different set of policy questions will arise.

- **Recommendation 13:** Government to re-consider the legal obligation to connect customers.
- **Recommendation 14:** Government to assess options for furthering the objective of creating a level playing field for competition.
- **Recommendation 15:** Government to evaluate the effectiveness of zoning and the need for co-ordinated switching.
- **Recommendation 16:** Government to consider modifying Ofgem's role to become a heat regulator rather than regulator of specific fuels.

We discuss each recommendation in turn below. Since these recommendations involve policy activity reasonably far in the future, we have not sought to assess the extent to which they can be considered "low regrets" – this should be undertaken nearer the time once the evolving picture is clearer.

6.3.1 R9: Government and Ofgem to adapt industry standards/network codes, and Ofgem's duties

Hydrogen is already captured under the definition of "gas" in the Gas Act.[89] However, many of the other pieces of secondary legislation, such as the Gas (Calculation of Thermal Energy) Regulations contain provisions that will need to be amended if hydrogen was to be provided.

Further, current network codes and industry standards are all documents based on the provision of methane/natural gas. These rules would all need to be modified to reflect a switch to hydrogen – for example to develop any new safety standards required. Complex network code reviews have historically been

[89] Section 48 of the Gas Act 1986 defines gas as (a) any substance in a gaseous state which consists wholly or mainly of (i) methane, ethane, propane, butane, hydrogen or carbon monoxide; (ii) a mixture of two or more of those gases; or (iii) a combustible mixture of one or more of those gases and air; and (b) any other substance in a gaseous state which is gaseous at a temperature of 15°C and a pressure of 1013•25 millibars and is specified in an order made by the Secretary of State.

lengthy and challenging processes, and sufficient time would need to be built in to ensure these modifications can be achieved.

We expect that BEIS and Ofgem would need to consider what would be required in this area (and the timelines for any changes) shortly after the GD2 and T2 reviews are concluded (i.e. early 2020s).

6.3.2 R10: Ofgem to establish the market and regulatory arrangements required for the provision of hydrogen.

In Exhibit 14 we showed the different components of a potential hydrogen supply chain. An important and open question is how to identify the responsible market player for each part of the hydrogen infrastructure; and accordingly to establish the relevant market and regulatory arrangements.

One possible option would be simply to capture all (or most) parts of the required hydrogen infrastructure under the umbrella of the incumbent network companies. This would have the benefit of facilitating the achievement of the co-ordination challenge across different parts of the infrastructure chain described above.

There is also precedent for including storage within the network's responsibilities. NTS and the GDNs face various system flexibility obligations and targets which means they already own and operate various intra-season and intra-day storage capacity, in order to meet security of supply requirements.

On the other hand, large-scale gas storage facilities (e.g. Rough, salt cavern storage etc.) are not owned by the network companies or charged for in network tariffs. It is also not clear whether vertical integration across large parts of the hydrogen supply chain would represent the optimal market structure.

A key question will therefore be whether parts of the supply chain (such as storage and SMR plant) can be considered competitive activities, or whether they represent natural or local monopolies.

For example, it seems likely that the LTS infrastructure will be economically similar to the existing gas network. We would therefore expect that ownership and operation of a hydrogen LTS ***could*** be embedded within the ownership of the current gas networks, and regulation of these assets could proceed in a similar way to RIIO (if not within the RIIO model). On the other hand, Ofgem has developed models under which tenders are run for independent operators to construct and own parts of the system infrastructure, particularly where these are large one-off assets. This could also be a valid ownership model if the investment required is sufficiently large to justify the tender process.

For other parts of the infrastructure this distinction is less clear. For example, if there could feasibly be multiple SMR sites with a variety of owners, each of which has access to markets on which hydrogen could be traded with retailers, then the market structure for hydrogen would begin to look like the current natural gas market.

Similarly, it is not clear that it would be appropriate for gas networks to incorporate the cost of appliance conversion into the RAB and under GDN ownership – since the boundary for where company assets belong has typically rested outside the home. If customers are therefore required to directly fund appliance conversion costs, there will be a need to consider whether Government support schemes would be needed to facilitate this for certain customer groups.

Exhibit 42 below sets out some initial views on the questions relevant for establishing the market and regulatory arrangements for different parts of the infrastructure chain.

Exhibit 42. Issues relevant for identifying appropriate model of ownership and regulation for hydrogen infrastructure

SMR	▪ Up-front investment required but costs largely marginal - plant can be scaled to meet demand, expect multiple units sited in proximity to storage facilities. ▪ Market could look like electricity generation, or methane wholesale today.
Hydrogen LTS	▪ Activity most similar to existing GDN activity – would expect therefore to embed this in existing regulatory model. ▪ Connection cost could be charged directly to SMR facility. Alternatively, if there is a case for socialising given carbon benefits, can be incorporated in RAB.
Hydrogen storage	▪ Geological constraints at present expect to constrain supply of storage capacity. ▪ Expectation is that some onshore underground storage facilities could work – but if storage capacity is limited there could be a case for regulation.
Burner installation	▪ Requirement here has parallels to smart meter roll-out. ▪ GDN responsibility for conversion could drive more co-ordinated regional planning and efficiencies – would need to include incentives in RIIO. ▪ Costs could be borne by customers or socialised in RAB.
CCS	▪ Direct government support for CCS has been withdrawn. Questions remain open around who could deliver CCS and how.

Source: Frontier Economics

A phased approach could be considered, whereby most of the activity could begin as a regulated activity to initiate action and achieve the necessary scale, after which supply activities could be moved into a competitive structure.

We have not sought, in this project, to identify recommendations, as consideration of these issues and appropriate market and regulatory structures will be a substantial task. The answer will depend on obtaining more clarity over time around the physical configuration of infrastructure, and accordingly an assessment of whether hydrogen markets are locally defined or national. The assessment of these issues will require engagement from Ofgem; BEIS; industry and other stakeholders.

This work is only likely to be possible once the research programme identified in Recommendation 3 has started to yield results – i.e. by the early 2020s at the earliest. At the same time, decisions on these issues are likely to be needed before any Government decision on the hydrogen switchover could be made. We would therefore expect this activity to be undertaken in the early 2020s.

6.3.3 R11: Government to consider how best to protect consumer interests in the event of a switchover.

A central challenge with any of the decarbonisation scenarios is to protect customer interests. With the possibility of Government decisions driving a wide-scale switchover programme, there are clear risks associated with ensuring customer acceptance. For example, it would be inefficient for customers to purchase a replacement gas boiler or a new gas cooker, only to then find that these appliances would need to be replaced or modified shortly afterwards.

Government and industry would therefore need to develop suitable public information campaigns, and consider whether specific protection (including financial support) needs to be put in place for vulnerable customers resulting from mandated changes.

Consideration also needs to be given to how customer fairness will be tackled, assuming that the different heating solutions result in different costs (both one-off conversion costs and on-going running costs). To the extent that the decision is mandated for customers, these differences become increasingly important and controversial. Indeed, any move to require certain customers to switch to a more expensive technology than other customers in neighbouring areas is likely to meet with considerable resistance and so risk becoming politically untenable.

While there are differences at present (particularly between the costs faced by those on and off the gas grid), these differences may increase further in future. Increased help will therefore need to be made available to vulnerable customers to either provide capital grants and/or ongoing subsidies to meet the higher payments or to subsidise connection to the cheaper heating options.

Given the timelines involved, we expect action in this area would need to be initiated in the early 2020s.

6.3.4 R12: Government to decide on geographical coverage of any hydrogen switchover.

For this report we have considered two scenarios – namely a national and a regional switchover – because domestic hydrogen consumption may more economic in northern regions of Great Britain, given geological storage capacity constraints.

However, this conclusion is by no means confirmed, and a programme of further research would be required to determine whether a regional or national switchover was physically possible, and economically preferable. That said, given that we would expect any hydrogen roll-out to be phased across the country, the Government could make such regional decisions in stages over time, most likely during the period 2025-30.

6.3.5 R13: Government to re-consider the legal obligation to connect customers.

Under the Gas Act, GDNs are under an obligation to connect any customer to the grid who requests a connection[90]. In scenarios where customers will need to

[90] Specifically, gas transporters are required to comply, so far as it is economical to do so, with any reasonable request to connect any premises to the network. Gas Act 1986, Schedule 9 - General powers and duties. In addition, under Schedule 10 - Duty to connect certain premises, customers residing within 23m of an existing gas main (and on the ground floor) are entitled to a gas connection at the standard network charge.

switch away from gas, Government may wish to re-consider this obligation, and place more restrictions on connecting customers.

6.3.6 R14 Government and Ofgem to assess options for furthering objective of creating a level playing field

One of the central challenges for enabling customers to make efficient switching decisions is to ensure there is a level playing field across different potential sources of heat provision. Incumbent gas networks operate under a stable and predictable model for network regulation which allows for efficient smoothing of cost recovery over long time-frames. Similarly, the up-front costs associated with switching away from gas are known to be a barrier to customer take-up of alternatives, unless the pay-offs from switching are achieved within relatively short timeframes.

These factors potentially combine to create a position where incumbent gas provision is entrenched; and inactive customers do not pursue switching options.

Government and Ofgem should continue to assess the effectiveness of policies for creating a level playing field. This would include, in particular, the application of carbon pricing to emissions from burning natural gas in homes; or continued subsidy of competing technologies to compensate for the absence of a carbon price on gas. These issues should be considered ahead of the projected acceleration of switching to alternative fuels in Scenario 1 and 2, from roughly 2030 onwards.

6.3.7 R15: Government to evaluate the effectiveness of zoning and the need for co-ordinated switching.

Our Scenario 2 is based on the assumption that there is co-ordinated switching away from gas networks to alternative electric sources, driven by either local or central Government. Such co-ordination would certainly facilitate decommissioning of the networks.

However, it is possible that decommissioning could also be achieved absent co-ordination. For example, in areas where non-co-ordinated switching has occurred, the network companies could be incentivised, through the RIIO controls, to identify areas of the networks where inefficiently low numbers of customers remain on-grid, and develop mechanisms by which both those customers and the network companies could share in the efficiency benefits of decommissioning.

Zoning and co-ordinated/mandated switching to alternative technologies might be necessary or beneficial for other reasons but we have not considered this question in this report. We note, however, that the Heat Networks Development Unit is already funding work by Local Authorities to undertake zoning and heat mapping, and Government should review how effective this has been. The timing of such a review is likely to be needed by the mid- 2020s at the latest.

6.3.8 R16: Government to consider modifying Ofgem's role to become a heat regulator rather than regulator of specific fuels.

It is challenging for Ofgem to incentivise companies to think equivalently across all possibilities for heating. Some industry commentators have noted that Ofgem's focus on regulating methane provision creates distortions to the level playing field for alternative providers of heat, and have proposed that Ofgem's role should be broadened to cover all heat sources.

Revisions to Ofgem's duties could be made such that Ofgem has a duty for regulation and oversight of markets and infrastructure for the provision of heat for customers. Ofgem's duties could also make direct reference to the need to ensure a level playing field across alternatives for heat provision.

These changes would have the effect of giving Ofgem a direct role in considering trade-offs across alternatives including heat networks and heat pumps as well as the potential for hydrogen provision.

However, implementing such a change would require substantial legislative reform, and is likely to be a time-consuming process. It is also currently unclear whether such changes would actually have a material impact.

In our previous report for the CCC, we concluded that there was no urgent need for such a policy in relation to district heating networks[91]. Clearly it is unrelated to the challenges of regulating the existing networks, which is the scope of this report. We have therefore not considered this question in great detail. We note, however, that if hydrogen is not viable, there would be a stronger case for thinking about this policy change ahead of the RIIO-GD3/T3 reviews.

6.4 Timelines for policy recommendations

Ofgem's upcoming price review will be undertaken between 2018 and 2020, and will determine revenue and cost allowances for the period 2021-2028. Further, under the Fixed-term Parliaments Act 2011, the current Parliament is expected to run to 2020.

The next few years therefore offer an opportunity for Government to put in place the necessary programme of research that will be required to inform decision-making in subsequent Parliaments. Ofgem, in the meantime, will need to implement regulatory solutions which ensure options remain open at the next reviews.

Scenarios 3 and 4 assume that hydrogen would start to come online by 2025. However, we understand from CCC that it may be more realistic to assume that hydrogen would be required by 2030. Given the expected construction and development lead times, we believe that a Government "yes/no" decision for hydrogen would be required 3-5 years in advance of the hydrogen being made available. Therefore, a Government hydrogen decision would be needed

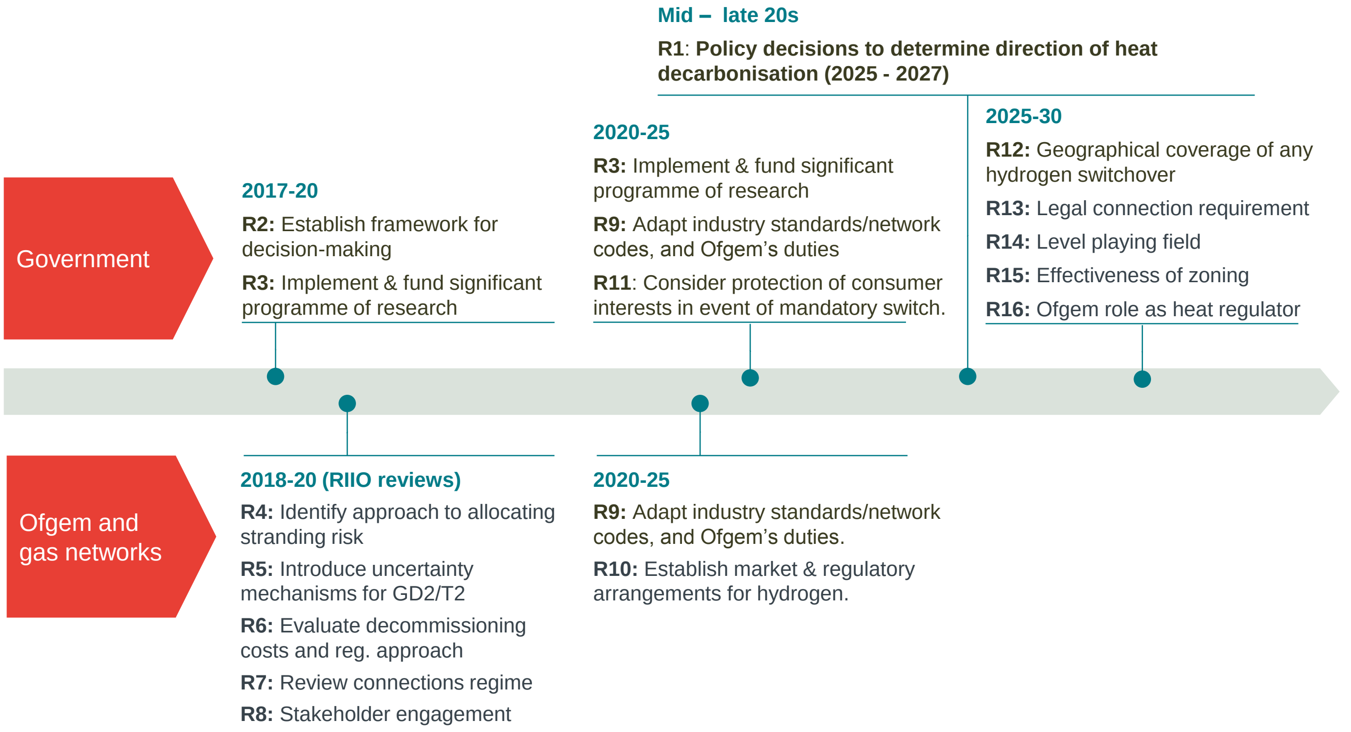
[91] https://www.theccc.org.uk/wp-content/uploads/2015/11/Frontier-Economics-for-CCC-Research-on-district-heating-and-overcoming-barriers-Annex-1.pdf

sometime between 2025-27 to allow hydrogen infrastructure to be operational from 2030.

If this is the case, a hydrogen decision is unlikely to be made by the time of the next price reviews, but could well affect network requirements before the GD3/T3 reviews. This is why Ofgem should ensure there is sufficient flexibility in the GD2 and T2 controls.

Our remaining recommendations fall into place around these key decision points. This timeline is illustrated in Exhibit 4.

Exhibit 43. Timeline for decision-making



ANNEX A NETWORK COSTS: UNDERLYING ASSUMPTIONS

To arrive at unit cost costs per km we have identified the network length of each operator using data from Ofgem and network companies in 2015, as shown in Exhibit 44.

Exhibit 44. Distribution networks and NTS – network lengths

Company	Network length (km)
National Grid - EoE	49,000
National Grid - Lon	20,000
National Grid - NW	33,000
National Grid - WM	23,000
Northern Gas Networks	35,000
SGN - Scotland	22,000
SGN - Southern	49,000
Wales and West Utilities	32,000
National Grid – NTS	7,500

Source: Ofgem network performance under RIIO (https://www.ofgem.gov.uk/network-regulation-riio-model/network-performance-under-riio/riio-gd1-performance-data, https://www.ofgem.gov.uk/network-regulation-riio-model/network-performance-under-riio/riio-t1-performance-data), National Grid's individual license areas sourced from National Grid 2014/15 performance report (http://www.talkingnetworksngd.com/price-control.aspx , SGN - Southern network length sourced from http://www.gasgovernance.co.uk/sites/default/files/Southern%20Transportation%20Charges%20April%202013.pdf

Below we describe the productivity factor we have used, before discussing each individual cost category in turn.

Efficiency improvement factor

In RIIO-GD1/T1, Ofgem applied an ongoing productivity assumption of 1% per year for opex and 0.7% for capex and repex[92]. Offsetting this productivity improvement (which serves to reduce costs over time) were Ofgem's projections for so-called Real Price Effects (RPEs) which serve to increase network costs over time in real terms[93].

In practice, Ofgem applies a single factor to networks costs that is the net effect of expected productivity improvements and RPEs, called the X-factor. Ofgem's allowance for RIIO-GD1/T1 based on the net impact of these two factors is shown in Exhibit 45.

[92] Ofgem (2012) RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas and Ofgem (2012) RIIO-GD1: Final Proposals - Supporting document - Cost efficiency.

[93] Ofgem's price control allowances are indexed to the RPI, reflecting the fact that inflation will drive up networks input costs over time. However, the RPI alone is not expected to fully capture the input price inflation networks are actually likely to face – i.e. because material and labour inputs will not necessarily evolve in line with headline RPI. Ofgem therefore allows for an adjustment to the real cost allowances to reflect expected RPEs, which can be specified as a % adjustment to costs each year.

Exhibit 45. Average annual productivity improvement factors net of RPE assumptions

	Opex	Capex	Repex	Totex
Gas Distribution networks	0.6%	0.2%	0.1%	0.3%
National Grid - NTS	0.4%	0.3%	0.3%	0.3%

Source: *Ofgem (2012), RIIO-T1/GD1: Real price effects and ongoing efficiency appendix*

For simplicity, we have applied a uniform x-factor of 0.5% to all costs after 2021 to reflect an average annual productivity improvement and RPE assumption going forward. We consider this is a reasonable long-term assumption to make to capture expected productivity improvements.

Reinforcement costs

Reinforcement costs are incurred for expansionary activities and represent the investment required to increase or enhance network capacity.

For distribution networks, we have used Ofgem's RIIO-GD1 final proposals for reinforcement costs up to 2021[94], shown in Exhibit 46.

Exhibit 46. Reinforcement costs for distribution networks based on Ofgem's final proposals

£m, 2014/15 price basis	2015	2016	2017	2018	2019	2020	2021
National Grid - EoE	17.9	15.2	13.9	11.0	11.1	10.8	10.7
National Grid - Lon	8.0	14.9	8.4	4.2	6.4	4.5	4.9
National Grid - NW	10.2	7.8	7.6	10.0	7.7	7.5	6.6
National Grid - WM	6.5	7.1	6.3	7.3	8.2	6.5	5.9
Northern Gas Networks	18.3	26.4	22.7	19.9	20.0	16.8	17.1
SGN – Scotland	23.6	19.8	23.8	20.2	19.6	18.0	17.6
SGN – Southern	11.1	21.9	30.5	33.6	37.3	22.4	21.5
Wales and West Utilities	25.2	23.5	22.9	24.6	22.6	21.7	23.8

Source: *Ofgem's final proposals, sourced from National Grid: Gas distribution full regulatory reporting supportive narrative (http://www.talkingnetworksngd.com/price-control-more-detail.aspx), Northern Gas Networks: ,RIIO Reports – GD1 Year 2 (http://www.northerngasnetworks.co.uk/ngn-and-you/document-library/) , SGN: SGN annual RIIO-GD1 report 2014-15 - supporting tables (Scotland) (https://www.sgn.co.uk/Publications/RIIO/), WWU: Regulatory Accounts (http://www.wwutilities.co.uk/about-us/our-company/publications/)*

Beyond 2021, we have assumed that the need for any GDN reinforcement costs depends on network throughput. At a high-level, this reflects the assumption that reinforcement will generally only be triggered if demand on the network is increasing. In general, given the scenarios described above, this means there is relatively little GDN reinforcement cost beyond the GD1 allowances[95].

[94] This is based on the sum of Ofgem's cost categories of mains reinforcement costs and LTS, storage & entry costs.

[95] With the exception of Scenario 3 (National Hydrogen) where we assume that GD1 allowances for reinforcement costs continue by 2050 with a productivity improvement.

For the transmission network, we use a similar assumption that reinforcement is only required where throughput requirements increase. As explained further below, this occurs only in Scenario 3.

Replacement costs

Replacement expenditure ("repex") is required to replace parts of the network as assets age or deteriorate.

For distribution networks, replacement expenditure is currently driven by the on-going HSE driven IMRP. The IMRP aims to replace "at risk" iron pipes with polyethylene (i.e. plastic) pipes by 2032. The "at risk" iron mains are defined to be those within 30 metres of a building. To allow Ofgem to set RIIO-GD1 allowances, the HSE classified "at risk" iron mains under three tiers to reflect different risk characteristics of these mains.

- Tier 1 "at risk" iron mains need to be decommissioned by 2032 or earlier.
- Tier 2 and Tier 3 "at risk" iron mains will be decommissioned on the basis of asset integrity assessment processes.
- The repex programme is mainly focused on urban areas as most "at risk" iron mains are in those areas. Further detail on the repex programme is provided in Annexe 2.

We use Ofgem's GD1 allowances for the category 'Total repex costs' for distribution networks until 2021. After this, replacement costs continue until the IMRP is expected to end (which varies depending on the scenario, as explained further below).

For the transmission network, the key driver for replacement requirements is the EU's Industrial Emissions Directive (IED), under which National Grid expects to be required to replace a number its compressor drives to meet the more stringent emissions standards[96]. The IED imposes limits on emissions which, according to NG, are expected to be violated at 17 out of the 24 compressor units it currently operates. NG expects these units will need to be phased out after 2023[97].

At RIIO-T1, National Grid requested allowances to ensure that it complies with the IED. However, at the time of the T1 decision there was some uncertainty around some of the IED requirements. Ofgem therefore determined a provisional baseline allowance of £269.3m (*2009 prices*) to cover these replacement costs, and introduced an uncertainty mechanism to allow a review of the allowances at certain trigger points during the price control period[98]. We understand that Ofgem has not adjusted this allowance to date.

For the purposes of our analysis, we have use Ofgem's RIIO-T1 final proposal allowances for the cost category 'Asset Replacement Capex' to cover the costs up to 2021.

[96] Gas compressors maintain the pressure on the NTS and ensure that flows of gas round the network are maintained.

[97] http://www.talkingnetworkstx.com/ied-why-is-ied-important.aspx

[98] See for example Ofgem (2015), IED decision letter, https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/150928_ied_decision_letter_rev._c_2.pdf

For costs beyond this point, we have estimated a replacement cost for the NTS based on the average cost per km of pipeline in RIIO-T1. This assumption reflects the fact that there will be no need to replace compressors on parts of the NTS which are decommissioned. We have assumed that the unit replacement costs for the NTS will remain at today's levels to 2050, assuming also an ongoing productivity improvement.

These are clearly simplifying assumptions. In practice the requirement for any replacement expenditure will be much more bespoke, depending on how many compressors are violating the IED and whether NG can identify alternative solutions which reduce replacement costs. Ofgem has also retained the option to review its allowances (which could move either up or down) under the RIIO-T1 uncertainty mechanism[99].

Other capex

Other capex includes mainly costs for IT and vehicles.

Exhibit 47 shows the annual other capex costs for the distribution networks and transmission network during GD1/T1.

Exhibit 47. Other capex costs for distribution networks and transmission network

£m, 2014/15 price basis	2015	2016	2017	2018	2019	2020	2021
National Grid - EoE	24.4	19.2	20.0	25.0	22.1	17.7	14.9
National Grid - Lon	12.7	10.8	10.0	13.6	12.9	7.9	7.2
National Grid - NW	17.2	13.3	13.2	15.5	15.4	14.1	10.8
National Grid - WM	18.8	9.7	8.5	12.3	10.6	10.9	6.6
Northern Gas Networks	30.4	25.3	24.8	14.5	14.8	17.8	18.1
SGN - Scotland	9.6	6.6	12.6	19.9	17.6	7.0	6.3
SGN - Southern	20.3	11.0	18.5	27.5	23.4	13.5	11.0
Wales and West Utilities	26.0	19.7	16.2	14.9	14.8	19.2	18.5
National Transmission system	21.8	4.9	4.3	46.5	52.2	40.9	36.8

Source: *Ofgem's final proposals, sourced from National Grid: Gas distribution full regulatory reporting supportive narrative (http://www.talkingnetworksngd.com/price-control-more-detail.aspx), Northern Gas Networks: ,RIIO Reports – GD1 Year 2 (http://www.northerngasnetworks.co.uk/ngn-and-you/document-library/) , SGN: SGN annual RIIO-GD1 report 2014-15 - supporting tables (Scotland) (https://www.sgn.co.uk/Publications/RIIO/), WWU: Regulatory Accounts (http://www.wwutilities.co.uk/about-us/our-company/publications/), NTS: (http://consense.opendebate.co.uk/files/nationalgrid/nationalgrid/transmission/NG_Gas_Transmission_Data_Tables.pdf)*

For the period from 2022 onwards, we assume these costs vary with km of pipe length, reflecting a high-level assumption that these costs are likely to vary depending on the scale of the network and the business. We calculate the unit costs by dividing the average GD1/T1 allowance shown above by the network length shown in Exhibit 44 above.

[99] For example, in its decision on NG's recent application to increase allowances Ofgem stated "Taking into account the conclusions of our consultants and the potential for further reductions in cost which they identified, we will want to consider whether there is a case to revise downwards the provisional allowance of £269.3m made in RIIO-T1 Final Proposals", Ibid, page 4.

Decommissioning costs

Some scenarios anticipate decommissioning parts of the gas network, reflecting a fall in gas demand in the scenario or changes in the flow of gas demand through the country.

There is significant uncertainty around the costs of decommissioning. This could range from repurposing the networks for alternative use, through to permanent abandonment.

For the purpose of our cost forecasts, we have made some assumptions on the cost of decommissioning supported by Aqua's industry expertise and verified by the ENA.

- For distribution assets, we assume that mains under 18'' diameter will remain in place, mains above 18" diameter will either be grout filled or removed.
- For mains under 18'' diameter, we apply unit costs for cutting, capping and nitrogen purge.
- We have assumed that all mains over 18'' diameter will require grout filling which is more expensive.
- We have estimated these unit costs, where available on the basis of historic NGN decommissioning costs. Where historical costs aren't available Aqua has developed unit cost estimates.

For transmission assets we assume that all mains are either grout filled or removed. The unit decommissioning costs for grout filling the NTS have been derived from Aqua estimates.

Using this methodology we have calculated average decommissioning unit costs of £0.03 million per kilometre for distribution networks[100] and £0.20 million per kilometre for the transmission network. However, we recognise that this is highly uncertain. Further research decommissioning requirements is needed to calculate decommissioning costs more accurately.

Maintenance costs

Maintenance costs are required to maintain the networks - essentially to repair broken equipment and assets.

Exhibit 48 shows the allowed maintenance costs for the distribution networks and transmission network up to 2021[101].

[100] National Grid provides an estimate of decommissioning costs of a total of £8 billion to decommission the whole gas distribution network. On the basis of a 264, 000 km assumption for the total gas distribution network (Ofgem; https://www.ofgem.gov.uk/network-regulation-riio-model/network-performance-under-riio/riio-gd1-performance-data), this corresponds to a decommissioning cost per km of £0.03 million per kilometre, in line with our estimate. Source for National Grid decommissioning cost: http://www.smarternetworks.org/Files/BioSNG_Demonstration_Plant_131203151750.pdf

[101] For distribution networks these costs include Ofgem's cost categories of work management, emergency, repair and maintenance. For the transmission network it includes faults and planned inspections and maintenance costs.

Exhibit 48. Maintenance costs for distribution networks and transmission network

£m, 2014/15 price basis	2015	2016	2017	2018	2019	2020	2021
National Grid - EoE	101.7	103.3	104.4	101.9	101.3	101.0	100.5
National Grid - Lon	76.0	78.5	82.3	80.8	79.6	79.1	75.3
National Grid - NW	75.2	75.7	77.8	75.7	74.3	73.7	72.0
National Grid - WM	56.8	57.8	57.6	57.4	57.7	58.5	56.4
Northern Gas Networks	75.2	75.4	75.3	73.6	73.3	73.0	72.3
SGN - Scotland	67.7	67.6	68.5	67.5	68.2	68.2	67.5
SGN - Southern	116.4	117.2	118.5	115.2	115.6	115.1	113.5
Wales and West Utilities	72.1	75.2	74.5	71.9	73.3	73.3	71.5
National Transmission system	41.6	47	57	62.7	63	57.8	53.5

Source: *Ofgem's final proposals, sourced from National Grid: Gas distribution full regulatory reporting supportive narrative (http://www.talkingnetworksngd.com/price-control-more-detail.aspx), Northern Gas Networks: ,RIIO Reports – GD1 Year 2 (http://www.northerngasnetworks.co.uk/ngn-and-you/document-library/) , SGN: SGN annual RIIO-GD1 report 2014-15 - supporting tables (Scotland) (https://www.sgn.co.uk/Publications/RIIO/), WWU: Regulatory Accounts (http://www.wwutilities.co.uk/about-us/our-company/publications/), NTS: (http://consense.opendebate.co.uk/files/nationalgrid/nationalgrid/transmission/NG_Gas_Transmission_Data_Tables.pdf)*

Beyond 2021 we assume that maintenance costs vary with the length of the network. Again this reflects the idea that if there is decommissioning there will be a lower requirement for maintenance (and vice versa if there is network expansion). We calculate the unit cost by dividing the average of Ofgem's allowances from 2015 to 2021 by the network length.

On top of this (and in addition to the general efficiency factor) we make an adjustment to account for the IMRP. We expect that the replacement of aging or at-risk iron pipes with plastic pipes will reduce the maintenance costs for the GDNs (since the newer pipes are expected to be more reliable and result in fewer leaks). To reflect this, we have assumed a 1% reduction per annum of maintenance costs, adjusted for the proportion of the network that is in urban areas (since repex will be focussed in these areas). This cost reduction finishes when the IMRP programme ends.

Overheads

Overheads or "business support costs" cover cost items like HR; regulation; and buildings. Essentially these are costs required for the functioning and running of the business.

Ofgem's cost allowances between 2015 and 2021. These are shown in Exhibit 49[102].

[102] For distribution networks, we use Ofgem's cost categories for total indirect costs which includes business support and training & apprentice costs. For the transmission network we use Ofgem's categories of business support and closely associated other indirect costs. Closely associated other indirect costs capture a number of costs that support the operational activities of the NTS, including operational training, engineering management, project management and other costs.

Exhibit 49. Overhead costs for distribution networks and transmission network

£m, 2014/15 price basis	2015	2016	2017	2018	2019	2020	2021
National Grid - EoE	35.3	35.1	35.2	35.4	35.7	35.6	35.2
National Grid - Lon	21.0	20.8	20.7	20.5	20.8	21.4	21.7
National Grid - NW	25.2	25.3	25.7	26.1	26.4	26.5	26.8
National Grid - WM	18.1	18.5	18.7	19.0	19.1	19.2	19.3
Northern Gas Networks	24.3	24.6	24.8	24.9	24.9	25.0	24.7
SGN - Scotland	17.9	18.1	18.2	18.2	18.3	18.3	18.3
SGN - Southern	32.7	32.8	32.9	32.9	33.1	33.3	33.3
Wales and West Utilities	26.8	27.4	28.1	28.4	28.4	28.5	28.3
National Transmission system	36	37.3	37.3	37.6	37.7	38.2	38.6

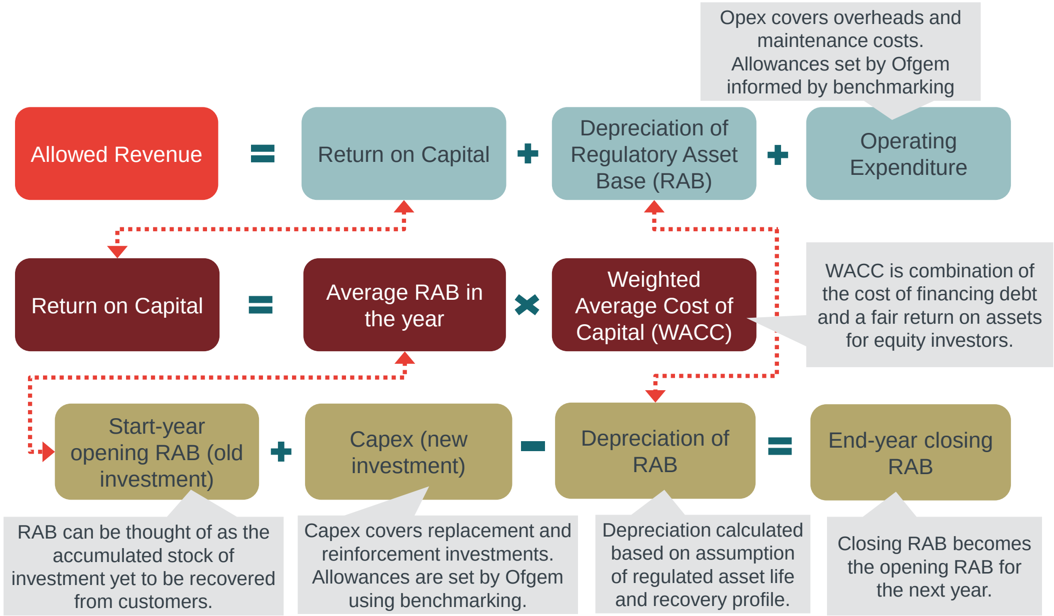
Source: *Ofgem's final proposals, sourced from National Grid: Gas distribution full regulatory reporting supportive narrative (http://www.talkingnetworksngd.com/price-control-more-detail.aspx), Northern Gas Networks: ,RIIO Reports – GD1 Year 2 (http://www.northerngasnetworks.co.uk/ngn-and-you/document-library/) , SGN: SGN annual RIIO-GD1 report 2014-15 - supporting tables (Scotland) (https://www.sgn.co.uk/Publications/RIIO/), WWU: Regulatory Accounts (http://www.wwutilities.co.uk/about-us/our-company/publications/), NTS: (http://consense.opendebate.co.uk/files/nationalgrid/nationalgrid/transmission/NG_Gas_Transmission_Data_Tables.pdf)*

We assume overheads vary with network length as a proxy for the scale of the business. In reality, we expect some of these costs to be fixed in the short term but most will be variable in the longer-term.

ANNEX B BUILD-UP OF ECONOMIC MODEL

Exhibit 50 below sets out the general building blocks of Ofgem's regulatory model.

Exhibit 50. Key building blocks of economic regulatory model



Source: Annexe 2

Below we summarise our assumptions and calculations for each of the building blocks. In general our approach has been to use Ofgem's parameter values from its RIIO-GD1/T1 regulatory model[103] as the basis for our projections to 2050. For the purposes of this work, we assume that there is no change to the parameters to 2050. This assumption allows us to understand the scenario outcomes given the current regulatory model.

Return on Capital

Ofgem gives an allowance to regulated networks to cover their cost of raising the funds for their activities, in particular their capital expenditure programme. As most firms hold debt and equity, the cost of capital is a weighted average of the two, referred to as the Weighted Average Cost of the different types of Capital (WACC).

We use Ofgem's assumptions on the WACC from RIIO-GD1/T1. This is shown in Exhibit 51.

[103] RIIO-GD1 Price Control Financial Model following the Annual Iteration Process 2015, RIIO-T1 Price Control Financial Model following the Annual Iteration Process 2015.

Exhibit 51. Vanilla WACC (real)

	2015	2016	2017	2018	2019	2020	2021
Gas distribution networks	4.1%	4.0%	3.9%	3.9%	3.9%	3.9%	3.9%
National Grid – Gas transmission	4.3%	4.1%	4.0%	4.0%	4.0%	4.0%	4.0%

Source: RIIO-GD1 Price Control Financial Model following the Annual Iteration Process 2015, RIIO-T1 Price Control Financial Model following the Annual Iteration Process 2015.

To calculate the WACC allowance, Ofgem applies the WACC to the average of the opening and closing RAB[104]. We follow a similar approach.

As shown in the table above, the WACC changes in the first years of RIIO-GD1/T1. This is because Ofgem updates the cost of debt on an annual basis with reference to a trailing average index of debt costs. However, the cost of equity set at the start of the price control review is not modified during the price control period.

The regulatory year 2017[105] reflects the latest information on the 10-year trailing average of debt costs[106].

For the purposes of our calculations, we assume that the WACC shown in 2017 stays the same up to 2050. This is a simplifying assumption as in reality we expect the allowed cost of debt to change in the remaining years of RIIO-GD1 and RIIO-T1[107]. In addition, Ofgem will very likely change the cost of equity parameters in future price control reviews depending on factors such as the prevailing macroeconomic environment and changes to the risks faced by networks.

Depreciation of RAB

For the purposes of calculating depreciation allowances, Ofgem divides the RAB to two asset types[108]:

- Pre-vesting assets, which are assets in existence at the time of the privatisation (i.e. 2002).
- Post-vesting assets, which are assets accumulated after 2002.
- Pre-vesting assets have an asset life of 56 years and are depreciated using a sum of digits approach[109]. With this method most of the depreciation associated with an asset is recovered in the first few years of its asset life. This method accelerates the recovery of depreciation, in comparison to a straight line depreciation method where networks receive the same annual

[104] The closing RAB is discounted by Ofgem such that it is NPV neutral. We have not applied this level of detail in our calculations for simplification.

[105] Ofgem refers to it as 2016/17

[106] It captures the trailing average cost of debt up to end of October 2015. Ofgem, Cost of Debt Indexation Model 31 October 2015, https://www.ofgem.gov.uk/publications-and-updates/cost-debt-indexation-model-31-october-2015

[107] Given the way Ofgem calculates the cost of debt we can expect the cost of debt (and in turn, the WACC) to fall in the remaining years of GD1/T1.

[108] Ofgem (2011), https://www.ofgem.gov.uk/ofgem-publications/53838/t1decisionfinance.pdf

[109] Annexe 2

depreciation allowance for each year of the asset life of the asset. These assets will be fully depreciated by 2058.

- For post-vesting assets, Ofgem decided to apply a sum of digits approach for gas distribution assets, while retaining its straight line depreciation method for gas transmission assets[110] [111].

Operating expenditure

The regulatory model takes total costs and divides them between “fast money” and “slow money”. Fast money allows network companies to recover a portion of total expenditure (totex) within a one year period. Slow money is where costs are added to the Regulated Asset Base (RAB) and therefore, revenues are recovered slowly from both current and future consumers[112].

The rate that Ofgem divides totex to slow money and fast money is the capitalisation rate.

Ofgem sets the capitalisation rate at a rate consistent with its expected split between capital expenditure (capex) and operating expenditure (opex) over the price control period.

Capex and RAB

For the distribution networks, Ofgem applies a separate capitalisation rate for replacement costs (repex) and the remaining totex.

- Ofgem applies a capitalisation rate to repex which changes from 50% in 2013/14 to 100% in 2020/21;
- Ofgem applies a capitalisation rate of approximately 30% on average across the networks to the remaining totex.

For the transmission network, Ofgem has a different capitalisation rate for base costs and costs allowed through the uncertainty mechanisms. Uncertainty mechanisms allow changes to the base revenue during the price control period to reflect significant cost changes that are expected to be outside the company’s control. For simplicity, in our model we apply the base rate to the total cost forecasts (we expect the majority of the costs to be subject to the base rate).

Our assumptions on the capitalisation rate are shown in Exhibit 52.

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[110] Ofgem (2011), Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues, https://www.ofgem.gov.uk/sites/default/files/docs/2011/03/t1decisionfinance_0.pdf

[111] The change to sum of digits depreciation for post-vesting gas distribution assets meant an amount of catch up depreciation was created, i.e. depreciation which should have been charged into revenue for the period between 2002 and 2013. Ofgem proposed to unwind this during RIIO-GD1. We have made a simplification to Ofgem’s depreciation approach and have not captured this amount of historic unrecovered depreciation. This is a very small part of the annual distribution networks revenue in GD1(approximately 3%) and therefore, will not materially affect our analysis.

[112] Ofgem Glossary, https://www.ofgem.gov.uk/ofgem-publications/51906/rec-glossary.pdf

Exhibit 52. Totex capitalisation rate used by Ofgem in RIIO GD1/T1

	Non-repex rate	Transitional repex rate
National Grid – EoE	26.63%	Stepped from 50% in 2013/14 to 100% in 2020/21 in seven equal instalments of 7.14% per annum
National Grid – Lon	23.47%	
National Grid - NW	26.10%	
National Grid - WM	24.95%	
Northern Gas Networks	34.98%	
SGN - Scotland	35.13%	
SGN - Southern	32.23%	
Wales and West Utilities	35.78%	
National Grid Transmission	64.40% (base rate[113])	Non-repex rate applied

Source: *Ofgem (2012), RIIO-GD1: Final Proposals - Finance and uncertainty supporting document, Table 2.4 and Ofgem (2012), RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Table 2.2*

In our regulatory model we assume that the capitalisation rates used by Ofgem in RIIO GD1/T1 will apply to 2050 for all scenarios.

Operating expenditure

Ofgem's operating expenditure allowance is the difference between the total costs and the portion of total costs that is capitalised (i.e. recovered as slow money). We apply the same approach.

Other cost allowances

Ofgem's final revenue allowances include an allowance for some additional items[114].

For the purposes of calculating allowed revenues in line with a GB-type regulatory model we have used inputs from Ofgem's economic model on tax allowances and non-controllable opex.

Ofgem has built a very complicated model to set networks' tax allowances. We have made a simplifying assumption to project tax allowances forward, as it is beyond the scope of this report to project tax allowances on that more complex basis.

To project these cost allowances forward, we assume that the tax allowance and non-controllable costs from RIIO-GD2 to 2050 will equal the average allowances over RIIO-GD1/T1 period.

113 The uncertainty capitalisation rate is 90%.

114 These include a tax allowance; non-controllable opex, which are costs not controlled by the networks (such as business rates) ; additional income, which is derived from the application of the IQI mechanism ; and core direct allowed revenues terms (DARTs), are items that do not go through the totex incentive mechanism such as pension deficit repair costs, pension administration and PPF levy and revenues from previous price controls . See Ofgem(2012), RIIO-GD1: Final Proposals - Finance and uncertainty supporting document.

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