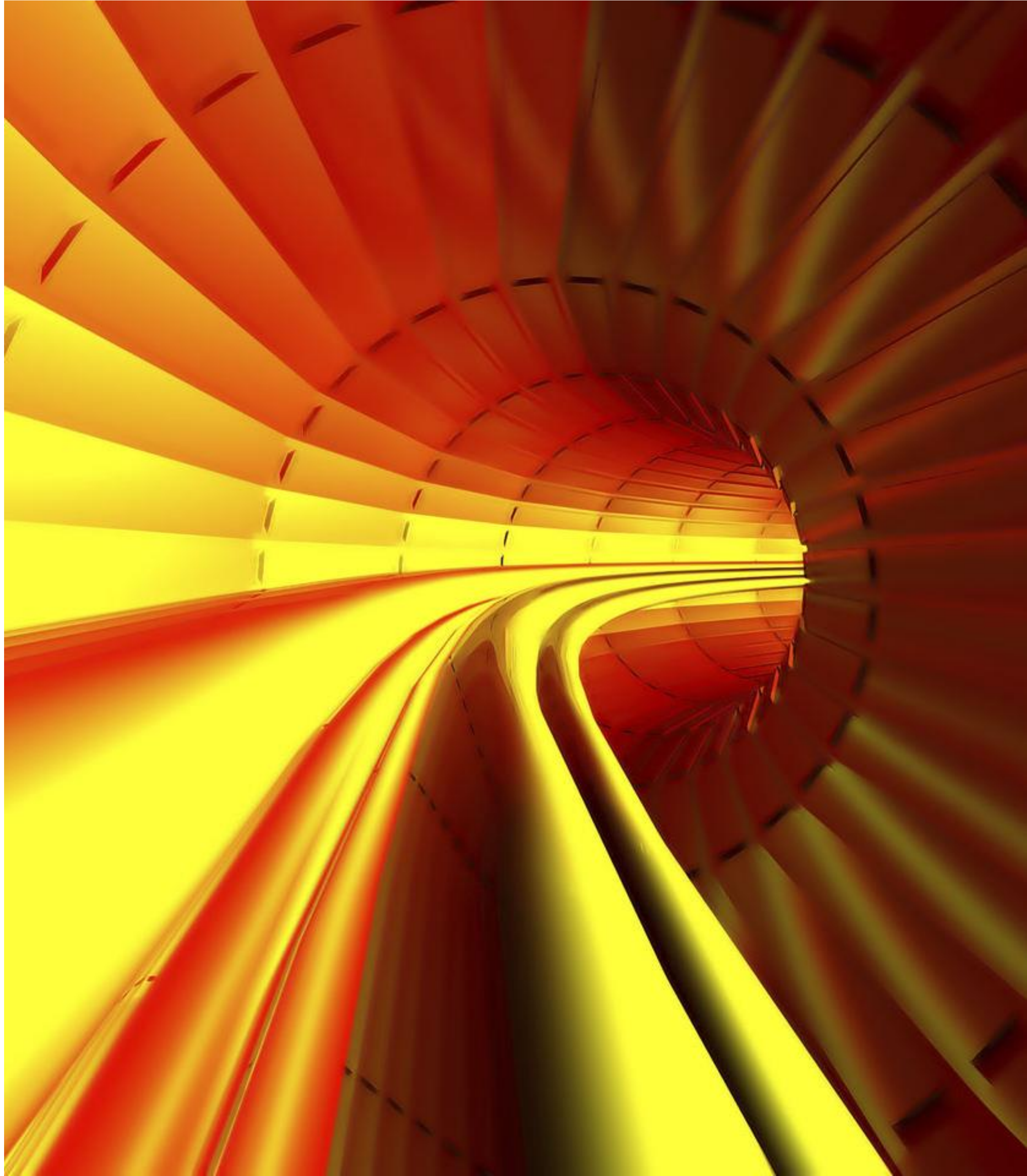
Future of Great Britain's Gas Networks

Report for National Infrastructure Commission and Ofgem

Final Report



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Report Contents

Glossary of terms

Term / Abbreviation	Meaning
AGI	Above Ground Installation
BEIS	Department for Business, Energy and Industrial Strategy
CCC	Climate Change Committee
CCUS	Carbon Capture, Usage and Storage
CHP	Combined Heat and Power
CO2	Carbon Dioxide
DESNZ	Department of Energy Security and Net Zero
ECV	Emergency Control Valve
EHB	European Hydrogen Backbone
ESO	Electricity Systems Operator
EV	Electric Vehicle
FEED	Front End Engineering and Design
FES	Future Energy Scenarios
GB	Great Britain
GDN	Gas Distribution Network
GW	Giggawatt
HDPE	High Density Polyethylene
HE	Hydrogen Embrittlement
HGV	Heavy Goods Vehicle
HP	High pressure
HSE	Health and Safety Executive
I&C	Industrial and Commercial
IMRRP	Iron Mains Risk Reduction Program
IP	Intermediate pressure
LP	Low pressure
LTS	Local Transmission System
mBar	Millibar

Term / Abbreviation	Meaning
MEAV	Modern Equivalent Asset Value
MOB	Multiple Occupancy Building
MP	Medium pressure
NGN	Northern Gas Networks
NGT	National Gas Transmission
NIC	National Infrastructure Commission
NTS	National Transmission System
OEM	Original Equipment Manufacturer
Ofgem	Office of Gas and Electricity Markets
PE	Polyethylene
PRS	Pressure Reduction Station
PSR	Pipeline Safety Regulations
RRP	Regulatory Reporting Pack
scm/h	Standard cubic meters per hour
SGN	Scotia Gas Networks
SWIC	South Wales Industrial Cluster
TWh	Terrawatt-hour
UK	United Kingdom
WWU	Wales and West Utilities

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Analysis figure index

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1 | Executive Summary

1 | Executive summary

This Study Assesses How the Gas Network Might Evolve in the Future

The National Infrastructure Commission (NIC) and Ofgem commissioned this study to investigate capital cost scenarios for the transition of the gas network (between now and 2050), based on varying levels of hydrogen uptake within GB's domestic, non domestic and industrial energy mix. The study provides a top down assessment of the network assets to identify the following aspects:

- Activities required to transition from the current situation to the future state.
- The operational implications of these activities.
- The timing of the activities.
- Illustration of the costs of making the transition.

Considering the uncertainties involved in the in the future transition, three illustrative scenarios were defined to demonstrate the range of possible futures and associated system level costs.

Project parameters and limitations

This report was commissioned to look at the capital costs associated with the transition of the GB gas network only. The extent to which the system is converted or decommissioned is dependent on many factors, and only one of these is cost. Others include the ability to meet the carbon reduction budgets, the consumer acceptability of the solution, requirement to balance low carbon energy system delivery models and the comparative benefits to the GB economy. Within the cost element, there are several items to be considered, including deliverability.

The costs associated with the conversion to hydrogen include cost of the hydrogen, capital investment in new assets, cost of converting existing assets, operational costs, cost of the transition (network and consumer), cost of legacy assets.

The costs associated with alternatives to hydrogen are cost of the energy, capital investment in new assets, cost of adapting existing assets, operation costs, cost of transition (network and consumer), cost of legacy assets.

Arup was commissioned to review a subsect of these costs; those that directly relate to the gas networks' costs and their existing ownership boundary. As per the scope of the project and the limitation to consider technical capex costs only, Arup excluded wider transition costs including the cost of producing hydrogen, the costs of any hydrogen storage and the costs associated with converting customer appliances. Additionally in a non-hydrogen scenario, Arup have excluded the costs associated with building out the electrical networks and security of supply, customer appliance costs, customer heating equipment costs. With regard to decommissioning costs Arup have excluded any remuneration of the gas networks for the existing RAV, as well as the wider costs of winding down the networks e.g. pension liabilities etc.

It is therefore important when reading this report to be aware that it only covers some of the infrastructure capital cost elements that need to be considered, and that infrastructure capital cost is only one of a number of elements to evaluate with determining the role that hydrogen might play in a net zero energy system in 2050.

This report:

- Provides a high-level estimate of the transmission and distribution elements of the capital infrastructure costs, not production, storage etc.
- Makes recommendations on where further work is required to reduce cost uncertainty within the assessment parameters.
- Recommends the further work that is required to allow for a full comparative cost assessment of the scenarios developed in this report.

1 | Executive summary

Project methodology

A model was built for this study based on a review of the available literature and engagement with key stakeholders. The steps in the process are summarised below:

1. **Literature review:** Research into the conversion of gas networks to hydrogen and considerations for decommissioning. This provided an evidence base from studies within GB and international markets to inform the assumptions and boundary conditions for the study.

2. **Stakeholder engagement:** We spoke to key stakeholders in the GB gas industry, including the gas network operators and public sector institutions to gather insights and opinions to help shape the transition modelling and cost assumptions and constraints as well as technical data for the modelling. The stakeholder input was tested and assessed by Arup's own experts, with final decisions made by the Project team (Arup, NIC and Ofgem).

3. **Definition of scenarios:** Three scenarios were selected from National Grid ESO's Future Energy Scenarios (FES) report. The scenarios were chosen to represent the broad range of possibilities for the future of GB's gas networks, considering the many uncertainties that face the market. They were selected in consultation with stakeholders and are as follows:
   - "System Transformation" was selected as the High Case for hydrogen demand
   - "Consumer Transformation" was selected as the Low Case for hydrogen demand
   - "Leading the way" was selected as the Balanced Case, representing a reasonable middle ground

   These scenarios have been refined in some respects to align with the latest findings from the literature review, stakeholder engagement, and to meet the overall aims of this Project.

4. **Transition methodology:** It will be a complex task to transition the gas network to a future state with some combination of operating with hydrogen and decommissioning certain parts. Some components within the network can be used with hydrogen without needing any changes, others will need repurposing, while there will be some that need replacement. The task will also involve multiple stakeholders to ensure that customers are not adversely affected through the course of the transition. This study developed a transition methodology based on assumptions for all these aspects, drawing on the current understanding from the literature review (step 1) and stakeholder engagement (step 2), to feed into a model that will assess the activities required and sequencing of the activities, taking into account the operational limitations.

5. **Cost Assumptions:** Once the Transition Methodology was agreed with the Stakeholder Group, we proceeded to the development of a set of cost assumptions against each of the steps in the method. These cost assumptions are largely based on existing costs from similar activities, adjusted appropriately to reflect volume changes and other impacts. As an example, the cost of disconnecting a customer was taken from publicly available quotes from the networks, with a 20% discount applied in order to reflect the economies of scale associated with the methodology.

6. **Modelling the scenarios**: We developed a model to represent the transition methodology in step 4 and the costs assumptions in step 5 and applied this to the three scenarios defined in step 3 to estimate the costs that could be involved.

7. **Sensitivity analysis**: Several of the assumptions were subject to sensitivity analysis to understand the relative impact of the assumption and support identification of areas for future work to reduce uncertainty.

8. **Draw conclusions and make recommendations:** We have drawn both qualitative and quantitative conclusions from the work and made recommendations for next steps.

1 | Executive summary

Qualitative conclusions and observations

From the modelling and the sensitivity analyses, we have drawn the following observations:

The evidence that large amounts of the existing network is suitable for hydrogen is unequivocal

Polyethylene (PE) pipe and low strength steel are suitable for hydrogen. There is still some uncertainty over high strength steel used in parts of the high pressure network. The current assumption is that iron isn't suitable due to safety concerns (as per the HSE).

The network is sized appropriately with little need for reinforcement despite the lower energy density of hydrogen. Energy density is offset by a number of factors including lower overall gas demand in all scenarios, assumed higher throughput in hydrogen scenarios, assumed higher operating pressure as a result of a 100% PE distribution network.

This means 83% of the network today is considered suitable for hydrogen. By 2032 when the iron mains risk reduction programme is scheduled to be complete this will be 99%. In addition, there is an on-going programme of research determining the hydrogen suitability of a wide range of non-pipeline network assets and their suitability for hydrogen. This project has taken a conservative view on the outcome of this research programme, and our high-level sensitivity analysis shows that the outcome is not material to the conclusions of this report.

Transmission network build out between industrial clusters is needed early in all scenarios

The evidence indicates that a hydrogen backbone at transmission levels to be a crucial piece of infrastructure required early to enable the transition, under all scenarios, as a means of ensuring a competitive market for hydrogen, resilience of supply and enabling industrial switching. We have assumed that initially this will likely be a new build development as a conservative cost assumption with savings opportunities where re-purposing proves possible. This backbone forms a material part of the costs in all scenarios.

The costs and method for converting the network to hydrogen and transferring customers is relatively certain.

Since the method for conversion is very similar to the process that was followed in the 1960s when the network was converted from Towns Gas to Natural Gas there is less uncertainty over these costs than the decommissioning costs.

Optimised strategies and methods for decommissioning gas system assets and managing on-going liabilities is uncertain.

Limited work has been done to investigate the best way to decommission large portions of the gas network and hence the costs associated with disconnecting customers, removing the natural gas from the system, making the network safe and permanently decommissioning. This study has made assumptions based on the current approaches, but it is possible that other more cost-effective solutions can be found. As per the offshore industry, we would expect specific guidance on the regulatory and safety aspects to be issued for the onshore gas system. There is a balance to be struck between upfront investment and on-going expenditure and liability. Some assets will need to be removed and others made safe to avoid issues such as road subsidence whilst others could be transferred to a publicly owned body who will retain liability for the assets and incur operational expenditure ensuring on-going public safety.

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Qualitative conclusions and observations cont’d

The cost of disconnecting customers is a significant cost driver.

The estimated costs of disconnecting customers from the gas network has a large influence on the overall costs, especially in the Low and Balanced scenarios. This study assumed a 20% cost efficiency over current disconnection costs which are well understand but further cost reductions could be possible if customers are disconnected in large groups in a coordinated way. The implementation model and the consumer experience concerns could have a major impact on these disconnection and decommissioning costs. The lack of clarity on this has led to this being an area of significant cost uncertainty.

Timescales for implementation and delivery are already looking challenging.

This assessment has developed a high-level schedule for each scenario that has considered the key activities required for each one. Whilst a formal assessment of deliverability was not included, it is already clear from this work that the timescales for all the scenarios is challenging, given the necessary sequence of events, the volumes involved and the practical limitations such as street works disruption and summer working.

There is still a high degree of uncertainty about how decarbonisation of gas might progress

Whilst substantial investment has been made in reducing the uncertainty in the ability of assets to accept hydrogen and for the network to operate safely, there is a high degree of uncertainty regarding transition research to date, both in terms of technical assumptions and cost assumptions. This is reflected in the range of cost levels calculated across the three scenarios. Additionally, the mechanics of how the entire energy system transitions at a system level, the customer journey, experience and support in transition is largely unknown and is not considered in the current industry research.

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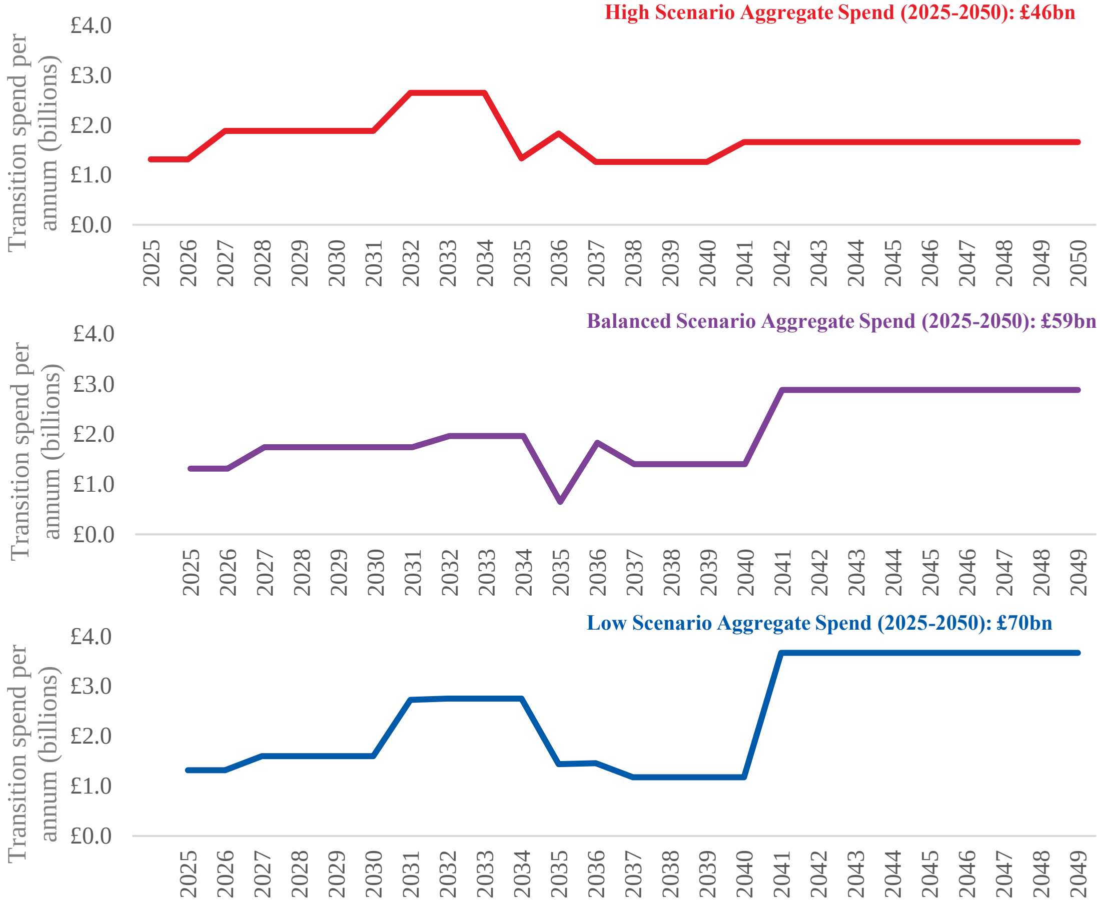
Quantitative outputs from the cost model

The charts show the estimated annual spend required to transition the gas network according to the three scenarios between 2025 and 2050. The annual spend is comprised of the following categories:

- **Direct investment in new infrastructure:** capital expenditure on new assets and repurposing of existing assets.
- **Network Transitioning:** Network costs associated with the switching from natural gas to hydrogen or permanently disconnecting them from the gas network.
- **Decommissioning:** Costs for permanently decommissioning parts of the network that are no longer required.

The key takeaways from the modelling include:

- Even though the High scenario requires the largest direct investment in new infrastructure (£37bn), it results in the lowest overall cost at £46bn.
- The Balanced scenario has an overall cost of £59bn with a relatively even split between direct investment (£20bn), network transitioning (£22bn) and decommissioning (£17bn).
- The Low scenario has the highest overall cost at £70bn, which is driven by the costs of network transitioning (£29bn) and decommissioning (£25bn).
- In terms of timing, the High scenario requires more spending prior to 2035 due to the required investment in infrastructure, whereas the other two scenarios incur higher costs post-2040 as customers are disconnected and parts of the network are decommissioned.



Comparison of annual spend between 2025 and 2050 for the three scenarios

Source: Arup analysis

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Sensitivity analysis

Following analysis on the uncertainty and materiality of the transition modelling for each scenario (see Section 7 for further details), two sensitivities were modelled.

Please refer to Section 7 for further details; both of these sensitivities assume significant changes to the existing legal / regulatory environment. This should be fully understood when referencing the outputs and impacts of this sensitivity analysis:

- A decommissioning sensitivity, applying a more considered methodology inspired by similar industry guidelines. This methodology was also applied to all aspects of the network, from NTS down to the LP distribution network.
- A customer gas disconnection sensitivity, applying a reduced unit cost on the basis of a series of assumptions that would simplify the process.

As evidenced on the charts to the right, the sensitivity analysis has the greatest impact on the Low and Balanced scenarios, with the decommissioning sensitivity increasing transition spend, and gas disconnection sensitivity reducing transition spend. High is largely unchanged and incurs the least spend across the basecase as well as the two sensitivities.

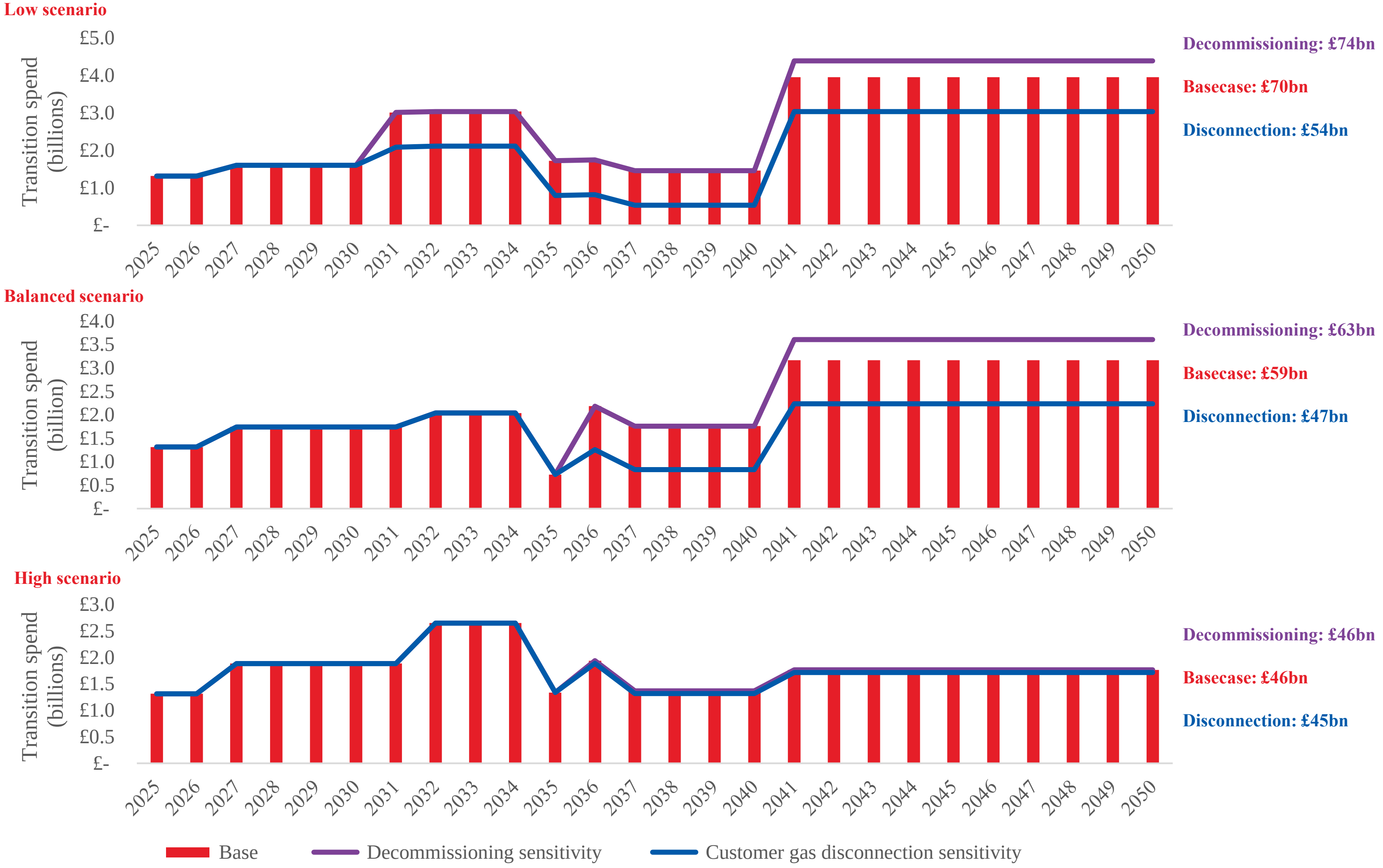

Figure 36. Comparison of annual spend between 2025 and 2050 for the three scenarios, incorporating sensitivity analysis

Source: Arup analysis

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Recommended next steps

As with any study like this, assumptions had to be made based on the best available information. The global evidence base for hydrogen conversion, transitioning and decommissioning is growing rapidly as we grapple with these important issues. During this study, we have identified a few themes that warrant further exploration.

Like for like full cost assessment of the three scenarios, considering all the costs.

No definite conclusions can be drawn from this report in isolation. Substantial areas of the overall cost of the three scenarios have not been included in the scope of this report. The future role of the gas network cannot be determined until a like for like full assessment is done across the whole energy sector using a consistent set of assumptions.

Implementation model and role of consumer choice

This project has made significant assumptions with regard to how these scenarios will be implemented, and the corresponding impact on customer choice. At a high level it is assumed that the transition, in whichever form, will be centrally mandated from Government. This brings with it fundamental changes to existing legislation around Customer's rights to a gas connection. Additionally, it is assumed that Customer choice is removed, both in terms of when they transition, and what they transition to.

These assumptions have been made with overall timelines in mind, with the 2050 deadline already considered challenging. There are a number of key issues that must be considered, primarily the inherent social obligations the gas networks have to customers; it would represent a significant shift in the social contract of the networks to allow them to forcibly disconnect customers. The recent initiatives deployed to customers in order to test the uptake of heat pumps has fallen very flat, despite significant financial incentives. Similarly, the issues seen in the hydrogen village trials have also hampered the rollout of hydrogen into the Customer home. In both instances Customers, and their inherent ability to choose, is causing problems in the rollout of the transition. Arup consider significant resource would be required in order to provide sufficient incentive, and to enforce the transition; Arup consider this is likely to add significant cost and potentially disrupt or delay the transition.

Deliverability and implementation

In conjunction with the like for like full cost assessment and the implementation model, a fully integrated schedule for all the activities across the three scenarios is required to ensure decision making is undertaken in a manner that minimises the overall system costs and enables the legally binding carbon budgets to be achieved. This will also enable a complete deliverability and supply chain readiness assessment to be undertaken.

Research is required to establish decommissioning guidelines for the transmission and distribution networks; a more refined bottom-up estimate can then be undertaken

More work is required to identify the best solution for each class of asset, and this will require negotiation and agreement between multiple stakeholders. Once this is done a bottom-up cost estimate can be undertaken to reduce the uncertainty on this cost element.

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Recommended next steps cont'd

A whole system plan for decarbonisation has yet to be developed

Although this project is focussed on hydrogen's role in the gas network, Government and industry stakeholders recognise that a whole system plan and planner is needed but this does not yet exist; we note the role of the future FSO in this regard The whole system plan should cover all energy vectors including electricity, gas, hydrogen, etc. as well as the interactions between them. Taking such an approach will provide better understanding of the potential overall costs of various pathways to net zero carbon emissions. In order to develop this plan, it is necessary to close the evidence gap that exists in how the transition could be implemented. Two areas in particular and how the consumer journey and experience can be optimised in a cost-effective way; and what level of future system resilience and reliability is required to ensure security of supply and how this is managed through the transition.

Urgent action is required to stay on track

This report had highlighted both substantial gaps in the evidence base for making an informed decision in 2026 (Government decision on whether hydrogen is part of the solution to decarbonising homes) and at a high-level identified that time for implementation from 2026 onwards is challenging. Urgent action is required to fully identify the substantive evidence gaps that are causing high levels of cost uncertainty in the like for like full cost assessment and close these evidence gaps. Without this, there can be no certainty that an informed decision can be made in 2026.

Additionally, the high level critical path analysis demonstrates the need for urgent decision making, particularly with regard to the build out of hydrogen backbone infrastructure at NTS and LTS level across all Scenarios.

The modelling will need to be refined as we learn more

Several research projects are investigating the remaining technical implications of converting the transmission and distribution networks for use with hydrogen. As further insights become available, these should be incorporated into the assumptions of future models. However, this report has high-lighted that the outcome of this research is not where the biggest areas of cost uncertainty are likely to be in a like for like full cost assessment.

2 | Project aims

2 | Project aims

The National Infrastructure Commission will publish its second National Infrastructure assessment in Autumn 2023, making recommendations to the Government that support the delivery of a 30 year plan for GB's economic infrastructure.

This study will also inform Ofgem's work on hydrogen and the future of natural gas network regulation. Ofgem will use the findings of this research to inform review of network companies' business planning submissions. This work will also support Ofgem engagement with government on the development of future regulatory frameworks for hydrogen transport.

This report provides technical information and insight from research and analysis to support considerations for GB's future gas networks.

Objectives

1. Build understanding of how strategic choices regarding the future of natural gas networks could impact the design and development of hydrogen networks in GB.
2. Assess the activities needed for decommissioning and the networks current potential for conversion to 100% hydrogen.
3. Build an understanding of the decision-making drivers (technical, operational and financial/economic) that could affect the rationale for different mixes of entirely new hydrogen infrastructure, natural gas infrastructure converted and a decommissioned infrastructure.

2 | Scope and underlying assumptions

Guiding principles

Outlined below are several supplemental guiding principles of the project that provide background context for this report:

- A scenario based ('top-down') approach was taken for this study, considering the relative immaturity of system-wide analysis and the high levels of uncertainty associated with the development of the future hydrogen economy in GB as well as the role that gas networks could play in its evolution. Hence, gas network data has been aggregated to a national system level for the analysis.
- Assets outside the current ownership boundary of the Gas Transmission and Gas Distribution Networks (GDNs) are not considered. For example, storage assets, customer meters, cost of new customer equipment (boilers and cooking appliances) are out of scope of the analysis.
- This report only covers the transition scenarios from the perspective of the gas infrastructure; any changes required to the electricity system, for example, have not been considered and is outside of scope.
- The literature review is intended to be a high-level summary of the key findings in the public domain as of March 2023, it is not intended to be an exhaustive review. The findings in this research have been summarised to support and supplement the high-level analysis undertaken in this project.
- This report uses a set of publicly available transition scenarios (National Grid ESO's Future Energy Scenarios) for the purposes of consistency and comparability with other existing and future work.
- The report does not assess the achievability of the transition pathways outlined in the model. Thus, considerations such as supply chain readiness, infrastructure for production, storage etc. of hydrogen are out of scope. Further, it has been assumed that the appropriate market framework will be established (including policy, regulatory and legal aspects) to remove barriers and enable the development of the scenarios as outlined. Additionally, it is assumed that all necessary support for the customer transition is provided through a centrally managed programme.
- Regional GDN cost data has been aggregated to a national system level.
- The scenarios will explore 100% hydrogen only, with interim hydrogen blending excluded from our analysis.
- In regard to how hydrogen is delivered to meet demand, the project team have considered a centralised transmission of hydrogen through a development of a hydrogen backbone. However, it should be noted that there are alternative approaches that reflect a more decentralised model of hydrogen distribution such as co-location of production and demand (utilising point-to-point networks) and vehicular-based transport such as trucks trailers, rail or ship [1]. It's likely that both centralised and decentralised modes for the supply of hydrogen will be developed concurrently.
- The adoption of these alternatives did not reflect the consensus established during our stakeholder engagement. The stakeholders involved provided detailed input in the merits of a network backbone from the perspective of market access and resilience to GB's security of supply.
- All pressures are presented in BAR (gauge), unless otherwise stated.

3| Stakeholder engagement

3 | Stakeholder engagement

Overview

This project adopted a consultative and collaborative approach to gain support and engagement, and ensure key stakeholder needs and challenges were addressed.

The table adjacent depicts the identified key stakeholders and groups to be involved at each step, their roles, needs and the value and outcome that the future of the network has to them.

Given the challenging project timescales, the project team relied on our collective existing connections into the identified stakeholder groups.

The objectives of the stakeholder engagement approach were:

1. Information sharing sessions to engage stakeholders, including technical network asset data.
2. Structured workshops to understand rationale behind key assumptions.
3. Dissemination of programme progress and outputs, including a workshop.

	Identify stakeholders	Identify assessment	Plan communication	Engage stakeholders
Task	Identify stakeholders group Identify individual stakeholders representatives Create initial stakeholder list	Conduct high-level stakeholder assessment Prioritise stakeholders and develop stakeholder map Develop stakeholder map	Create stakeholder planning sheet Identify engagement activities including scope for data requests Develop detailed engagement plan	Maintain plan to support ongoing engagement activities Execute stakeholder communication plan Monitor progress
Output	Stakeholders final list	Stakeholder map Engagement grid Updated stakeholder lists	Stakeholder communication planning sheet Stakeholder communications plan	Updated stakeholder communication plan Communication and engagement activities Feedback mechanisms implemented

Agile approach

Stakeholder Engagement

Knowledge sharing and Dissemination

Ongoing reporting and management

3 | Stakeholder engagement

Stakeholder groups

This project adopted a consultative and collaborative approach to gain support and engagement, and ensure key stakeholder needs and challenges were addressed.

Initially the project team identified the key stakeholders and groups to involve at each step, their roles, needs and the value and outcome that the future of the network has to them.

Given the challenging project timescales, the project team relied on our collective existing connections into the identified stakeholder groups.

The objectives of the stakeholder engagement approach were:

1. Information sharing sessions to engage stakeholders, including technical network asset data.
2. Structured workshops to capture rationale behind key network considerations and decision points.
3. Dissemination of programme progress and outputs, including a workshop.

The project team identified the following groups of stakeholders, according to their scope of input to the project:

Gas networks

All of the gas networks in GB were consulted, with assistance from the Energy Networks Association (ENA):

- Cadent
- National Gas Transmission
- Northern Gas Networks
- Scotia Gas Networks
- Wales & West Utilities

These stakeholders provided the following inputs to the project:

- Technical considerations regarding the hydrogen readiness of the existing gas system.
- Technical considerations with regard to customer transition.
- Technical considerations with regard to decommissioning.
- Operational considerations regarding the proposed transition methodologies.
- Technical asset data, in the form of the 2022 Regulatory Reporting Packs (RRPs).
- Unit cost data, aligned to the RRP under Ofgem's Modern Equivalent Asset Value (MEAV).

Government, Regulatory, Market stakeholders

This Stakeholder group were engaged towards the end of the project to gather wider views and commentary on the findings of the project. stakeholders included:

- HSE (Health and Safety Executive)
- DESNZ (Department of Energy Security and Net Zero)
- CCC (Climate Change Committee)

Other

Additionally, the project team engaged a variety of additional stakeholder inputs for review and challenge of the transition methodology and modelling assumptions including:

- Internal Arup domain expertise
- Arup's wider network including European GDN operators (e.g. OGE), equipment manufacturers (e.g. Siemens) etc.

3 | Stakeholder engagement

Stakeholder Sessions

As part of this project, Arup conducted extensive Stakeholder engagement, in the form of data requests, structured interviews and group workshops.

The table opposite presents a summary of the Stakeholder engagement. In addition, Arup requested Regulatory Reporting packs from each of the networks, alongside corresponding Modern Equivalent Asset Value (MEAV) data from which forms the detailed network data for the analysis. Note this data was collected under Non-Disclosure Agreements (NDAs), hence the anonymised data presented in this report.

Session	Date	Stakeholder	Participants
1. Stakeholder interview NGG	20/01/2023	NGG	NGG – 1, Arup – 2
2. Stakeholder interview WWU	24/01/2023	WWU	WWU – 1, Arup – 3
3. Stakeholder interview SGN	13/02/2023	SGN	SGN – 3, Arup – 3
4. Stakeholder interview Cadent Gas	14/02/2023	Cadent Gas	CG – 3, Arup – 3
5. Stakeholder interview NGN	15/02/2023	NGN	NGN – 1, Arup – 3
6. Stakeholder interview NGG	20/02/2023	NGG	NGG – 3, Arup – 3
7. Stakeholder interview WWU	24/02/2023	WWU	WWU – 3, Arup – 4
8. Stakeholder Workshop 1	03/03/2023	Group Workshop	NGG – 4, WWU – 3, SGN – 3, Cadent Gas – 3, NGN – 4, Ofgem – 1, NIC – 1, Arup – 5
9. Stakeholder Workshop 2	09/03/2023	Group Workshop	Ofgem – 2, NIC – 2, DSNZ – 6, Arup – 5
10. Stakeholder Workshop 3	15/03/2023	Group Workshop	Ofgem – 2, NIC – 2, NGG – 2, WWU – 2, SGN – 3, Cadent Gas – 2, NGN – 3, Arup – 5

4 | Literature review

4 | Literature review

Section overview

This section of the report provides a summary literature review of the existing hydrogen transition landscape, as well as signposting to key pieces of ongoing research.

A significant amount of work has been carried out across the sector, both on the supply and demand side of hydrogen, as well as by the networks on how to adapt the existing methane system to accommodate the new hydrogen gas. This section will help to provide the reader with a summary of said developments, as well as identify which pieces of research provide the basis for key assumptions in this project.

Section Navigation

- Technical considerations for hydrogen and its use in the existing gas system:
  - Characteristics of hydrogen vs natural gas; how both gasses differ and the impact these differences have on the network and customer appliances.
  - Impact of hydrogen on network assets; a detailed commentary on how hydrogen will impact the various component asset types of the network, and the likely implications.
  - Operational impacts of hydrogen; the operational implications of the differences in characteristics of hydrogen and natural gas, mainly the variance in volumetric density.
- Development of Hydrogen Clusters and the potential hydrogen backbone; a summary of the various hydrogen cluster developments, as well as the potential development of a hydrogen backbone as proposed by National Gas Transmission.
- Customer transition (to hydrogen or permanent disconnection from the network); a description of the likely customer experience and the changes required to the customer infrastructure and equipment.
- Decommissioning the network; the process of decommissioning under the current regulatory framework, and the implications for the network.

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4.1 | Technical considerations

GB gas system overview – network boundaries

The diagram opposite presents a simplified illustration of the GB gas system.

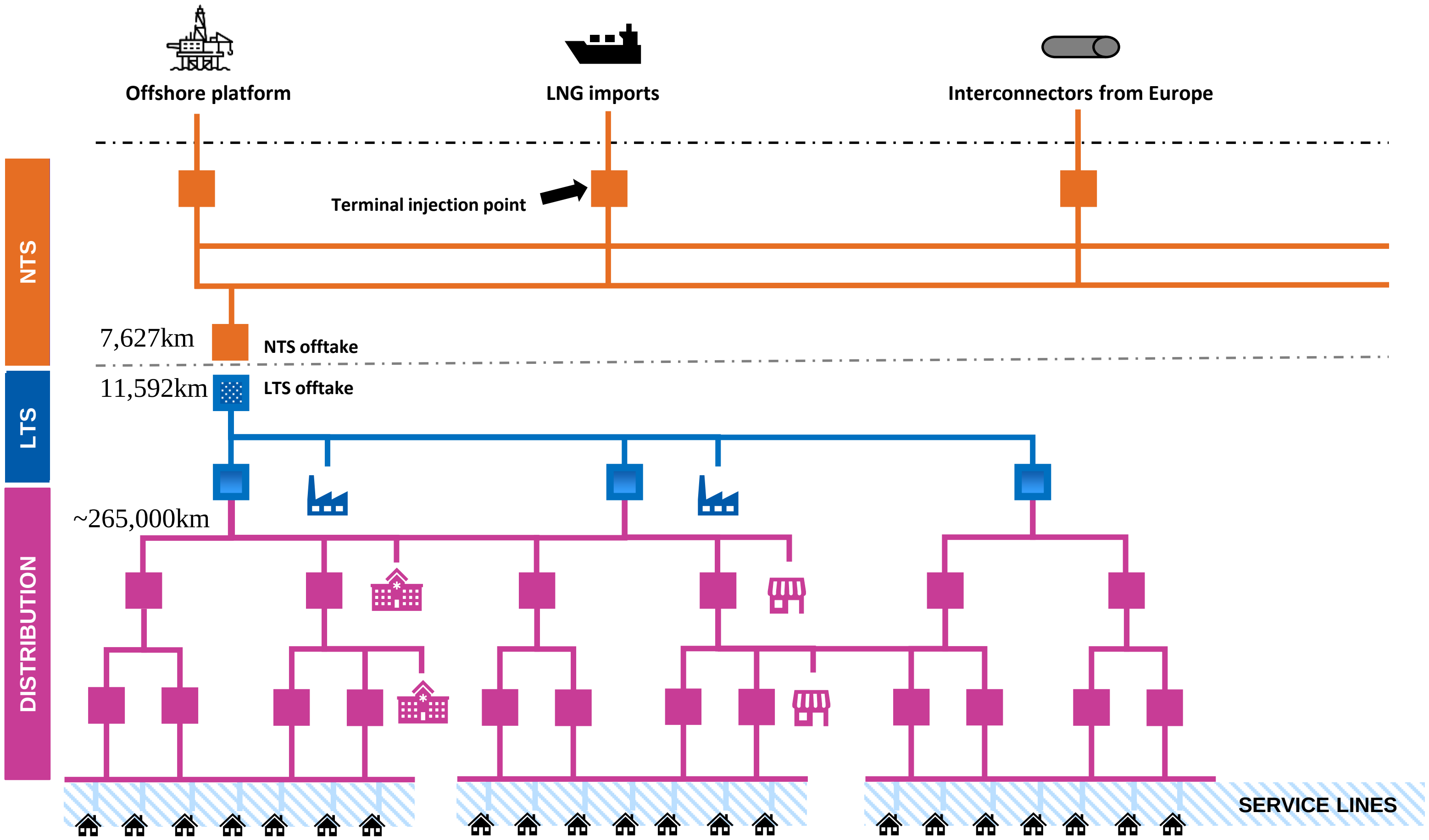
National Gas Transmission (NGT) operates the National Transmission System (NTS), a high pressure pipeline responsible for the transport of gas at a national level. This NTS is effectively also a storage asset given the large volumes of gas that are contained within the system.

Gas comes off the NTS at an offtake site. Such sites also represent the ownership boundary between NGT and the 8 Gas Distribution Networks (GDNs) among 4 ownership groups:

- Cadent
- Northern Gas Networks (NGN)
- Scotia Gas Network (SGN)
- Wales & West Utilities (WWU)

Within the GDNs there are 2 main tiers within the system:

- The Local Transmission System (LTS); a high pressure network responsible for the transport of gas within a region.
- The Distribution Network; a lower pressure system responsible for distributing gas around cities, towns and villages. This is the part of the network that connects the majority of customers.

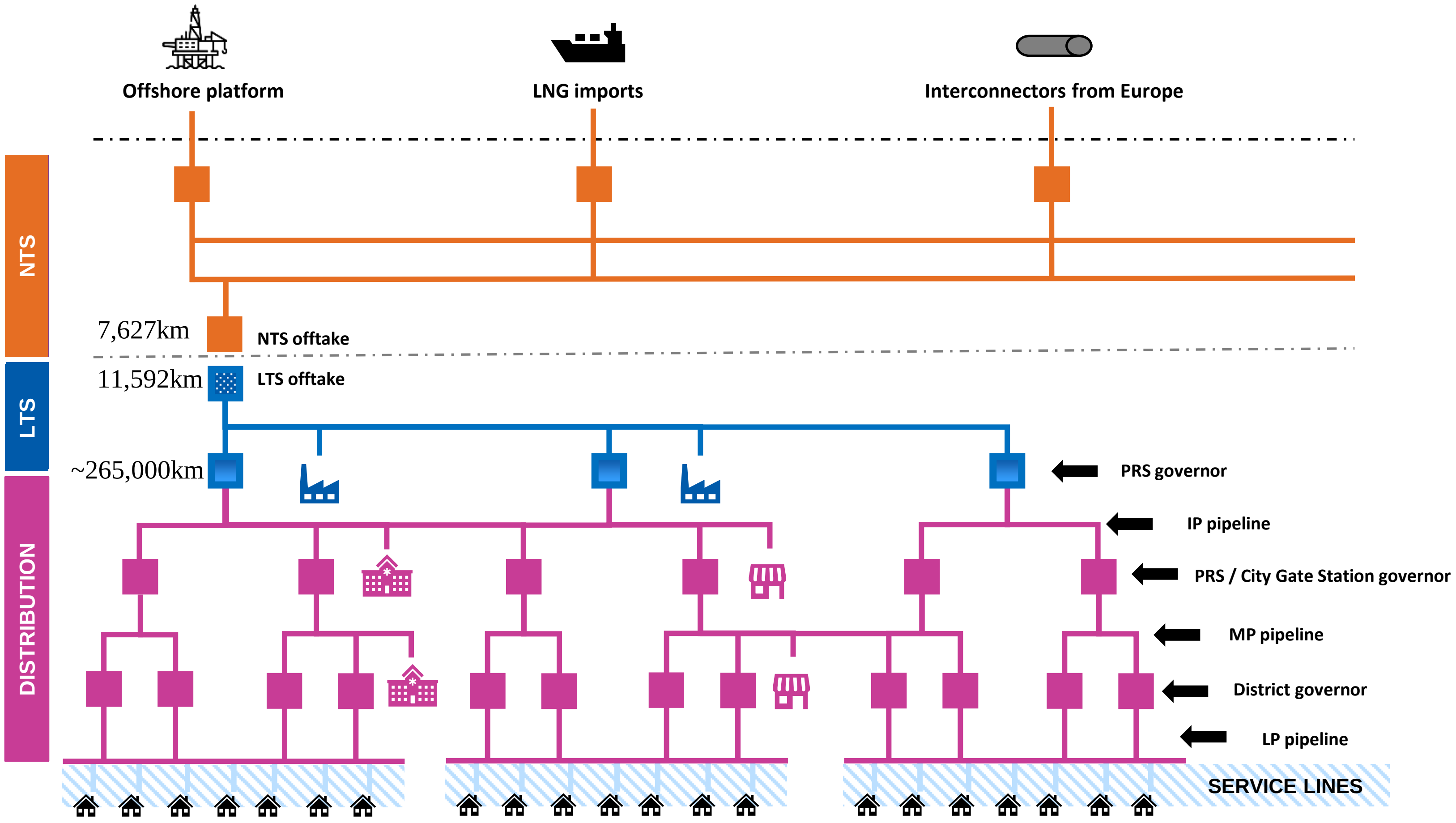


4.1 | Technical considerations

GB gas system overview - pressure tiers and pipeline materials

Each tier of the network has a different operating pressure:

- The NTS is the highest pressure within the network, operating at c. 75 bar. Due to the high operating pressures and volumes transported, the NTS is made from large diameter steel pipes.
- Similarly, the LTS also operates at high pressure using large diameter steel pipeline.
- The distribution network is comprised of up to 3 additional pressure tiers of between 7 and 0.075 bar - intermediate pressure (IP) medium pressure (MP), low pressure (LP), and- with pressure reduction equipment (governors) between each pressure tier.
  - The distribution network is typically comprised of polyethylene (PE) pipes such as high density polyethylene (HDPE) and medium density polyethylene (MDPE), however there are some legacy iron mains in the network. This iron is being phased out over time under a risk based framework, the Iron Mains Risk Reduction Programme (IMRRP).
  - The IP networks also contain steel or HDPE to manage the higher pressure.
  - MP networks predominately consist of MDPE.
  - Service pipes are what connect customers to the network. Whilst the majority of these are PE, there are some legacy steel and iron services in operation today. These legacy assets are also being phased out of the network when encountered as part of the IMRRP.



4.1 | Technical considerations

Hydrogen's impact on pipelines

Hydrogen has been demonstrated to cause integrity issues to metallic pipelines, known as hydrogen embrittlement which occurs during internal high pressure. Hydrogen embrittlement is a reduction in the ductility of the metal due to absorbed hydrogen; once absorbed, hydrogen lowers the stress required for cracks in the metal to initiate and propagate, resulting in embrittlement.

The steel and iron pipelines comprising the gas networks are affected by hydrogen embrittlement in different ways:

- High strength steel pipelines, typically found in newer lengths of the NTS, are not considered suitable for hydrogen given the operating pressure, molecular structure of the material and the relatively small thickness of the pipeline walls. NGT have identified that this comprises c.11% of its network.
  - Significant work is currently being undertaken to develop mitigations for high strength steel pipes, particularly in Europe where this material type represents a more significant portion of the total asset base. Some such innovations are graphene liners, or injection of water or oxygen into the gas mix; whilst significant research is underway, no verified solution is currently available.
- Lower strength steel pipelines, comprising the majority of the steel portions of the networks at NTS, LTS and distribution levels, is considered suitable for hydrogen as a result of a slightly different molecular structure and much thicker pipeline walls.
- The low pressure distribution networks contain a small percentage of legacy iron pipelines. As discussed with the Health and Safety Executive (HSE), iron is not deemed suitable for hydrogen, particularly given the age profile of the assets in the system (typically 50+ years old).
- The majority of the low pressure system is comprised of PE; PE is considered hydrogen ready, requiring no modification. It also has an advantage in that it has an extremely long asset life, with construction techniques that minimise the potential for leaks.
- Service pipes, connecting the customer home to the low pressure network, are typically either PE, or steel. In line with the rationale for material-based replacements further up the network, all non-PE services would be replaced. Note this is currently done in conjunction with the IMRRP.

In addition to pipeline material, pipeline condition must also be considered for the steel pipelines that are technically able to accept hydrogen:

- Whilst all networks operate appropriate integrity management systems, the age profile of these assets (some of these pipes are more than 50 years old) means some are unlikely to be suitable for hydrogen due to condition.
- NGT has identified that c. 9% of its asset base would not be suitable due to condition, with a similar figure expected for the LTS.

4.1 | Technical considerations

Hydrogen's impact on pressure equipment (compressors, governors)

Compressors

- Compressors are designed to operate under specific conditions, termed an 'operational envelope'. Given the difference in properties and resulting fluid dynamics, a natural gas compressor has a different specification to a hydrogen compressor.
- Whilst some of the Original Equipment Manufacturers (OEMs) such as Siemens, GE etc. are trialing hydrogen blends in legacy compressors with some promising initial results, the study assumed that NGT's compressor fleet would not be suitable for hydrogen conversion:
  - Whilst there is potential to modify the operational envelopes of compressors, the age profile of the existing fleet would likely be near end of life at the time of conversion. Therefore, there is an assumption that this will need to be fully replaced.
- The properties of hydrogen could also impact the compression design on the current system, as a result of increased pressure drop between compressor stations.
  - As a result, additional compressor stations may be required to maintain pressure and flow rates in the network.

Pressure reduction equipment (PRS, governors etc.)

- The following factors are considered to impact the suitability of pressure reduction equipment for hydrogen:
  - Materials; some equipment may contain high grade steels or legacy iron valves which are unsuitable for hydrogen.
  - Pre-heating equipment: hydrogen has a negative Joules-Thompson coefficient so the need for pre-heat can be removed (rather than dramatically cooling, like natural gas, hydrogen gets warmer during pressure reduction)
  - Flow rates; given the likely different flow rates, instrumentation etc. will likely need recalibrating to manage hydrogen. This would likely require new metering equipment, given the characteristics of the gas.
  - Valve seats: existing perishable parts (rubber) may not provide an adequate seal.

- Some OEMs have trialed hydrogen in modern pressure reduction equipment with no issues. Whilst this has yet to be confirmed and approved by the HSE, this study considers newer equipment could be modified to adapt to hydrogen, whereas older equipment would likely need replacing.

4.1 | Technical considerations

Logistical challenges created with pipeline replacement / new build

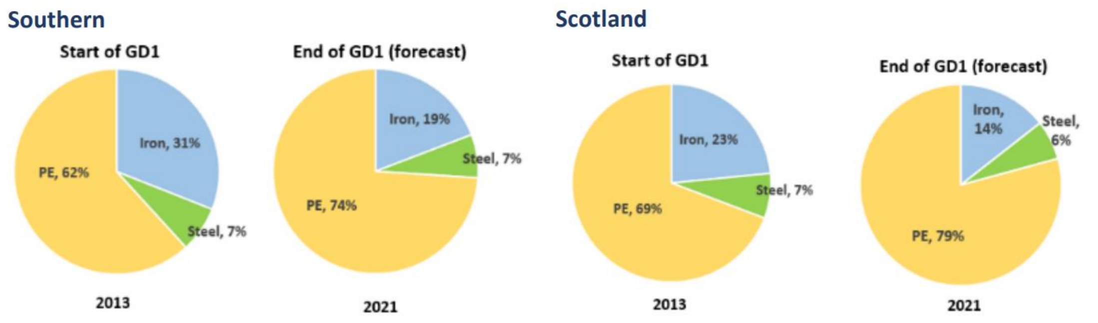
Context

- The current gas transmission and distribution network in GB is constructed from a number of different materials. These materials can broadly be split into iron, steel, and polyethylene (PE), with the majority of new pipes being PE.
- These materials have different technical characteristics and are able to transport hydrogen to varying degrees of effectiveness, with PE pipes considered to be more effective than metallic pipes.
- The older irons mains pipes are at a higher risk of failure through corrosion and fracture, and in 1996, the HSE mandated that all irons mains within 30m of buildings are to be replaced by 2032. These requirements were set on a safety case basis, and not for hydrogen operability reasons.

Iron mains and services replacement

The requirement to remove all of the iron from the distribution networks presents an equally, if not more significant challenge:

- IMRRP has been running since 2002/03, with the current programme of works committed until 2032. As per stakeholder discussions, the pace of the programme is largely dictated by access restrictions:
  - Given the gas mains are c.1m deep and run down the road network, towns and cities will restrict the number of works that can be carried out at any one time, to limit the impact on the residents. Furthermore, excavations are restricted to 100m in length also reducing efficiency and speed.
  - The networks consider it would take until 2040 to replace just 9,400 km under the current restrictions – an average rate of just 1,175 km per year [9 and 10]. The current IMRRP annual workload will aim to deliver more than this, see Ofgem GD1 annual reports/GD2 final determinations).



% of PE mains in gas networks at start and end of GD1 (SGN Network)

Source: SGN GD2 Business Plan, Repex Appendix, December 2019 [11]

4.1 | Technical considerations

Operational impact of hydrogen – dealing with volumetric density

In order to deliver the same amount of energy to customers, the network will have to throughput three times more gas by volume. This is either achieved by increasing the flow rate of the gas in the system, by increasing the pressure in the system or by installing more network to reinforce the system.

As discussed later in section 5.1, even under the high hydrogen scenario, the network is forecast to transport less energy in future. This is primarily driven by customers transitioning to electrification, and by an overarching trend of energy efficiency i.e. customers using less energy.

In the distribution network, the same volumetric density issues exist, however we consider them to be offset by making the entire network PE, and replacing the legacy iron:

- At the high pressure tiers in the network, mainly the NTS and LTS, it is considered that some additional network required to increase the network capability in order to offset the volumetric density issues.
- Due to how the iron mains were constructed, the joints between the pipes are prone to leakage. In order to reduce the incidence of leaks in the network, the GDNs typically operate the network at a pressure of 30mbar.
- The operating pressure could be increased to 75mbar which can be done in HDPE and MDPE pipes, thus mitigating the impact of volumetric density, as demonstrated by the H100 project.

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4.2 | Hydrogen clusters

Development of Hydrogen clusters around key industrial locations

Overview

As illustrated in the diagram opposite, at least 7 locations are current under consideration for development of hydrogen clusters. This section provides a summary of the existing developments as described by the Cluster stakeholders [19-28].

Acorn

The Acorn Project plans to build a CCS-enabled hydrogen plant at St Fergus in North East Scotland [28] which has an NTS entry point that could facilitate blending of hydrogen at low percentages and at scale. The project plans to use legacy infrastructure to transport captured emissions for storage under the North Sea.

Grangemouth

In North East Network & Industrial Cluster Development Summary Report, published in November 2021 [3], SGN investigated the potential to develop its gas networks to distribute hydrogen at scale in the North East and South Scotland.

Teesside and Humber

East Coast Hydrogen Feasibility Report, published in 2021, NGN, Cadent and National Gas Transmission investigated the feasibility of the conversion of the grid in the east coast region to distribute hydrogen [17].

Merseyside

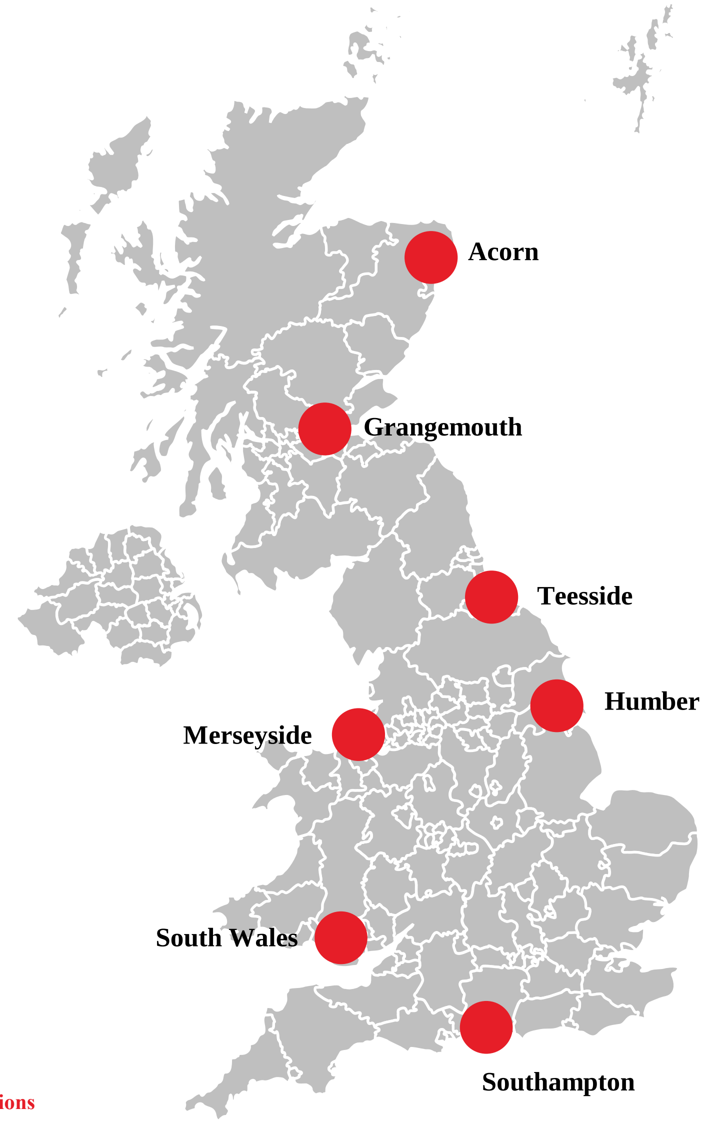
In HyNet North West From Vision to Reality Report, Cadent sets out its vision for its HyNet project which is an integrated low carbon hydrogen production, distribution and CCUS project which will run through Liverpool, Manchester and parts of Cheshire [18].

South Wales

South Wales has not yet published a cohesive plan for hydrogen uptake in the region however studies are in flight. For example, Wales and West Utilities have begun conducting a feasibility study on the development of a hydrogen backbone in the region. (SWIC plan will be published after the data gathering phase of this study).

Southampton

SGN and Macquarie's Green Investment Group commissioned WSP to conduct a feasibility study of hydrogen and CCUS uptake in the Solent area around Southampton.



Hydrogen cluster locations

Source: Arup analysis

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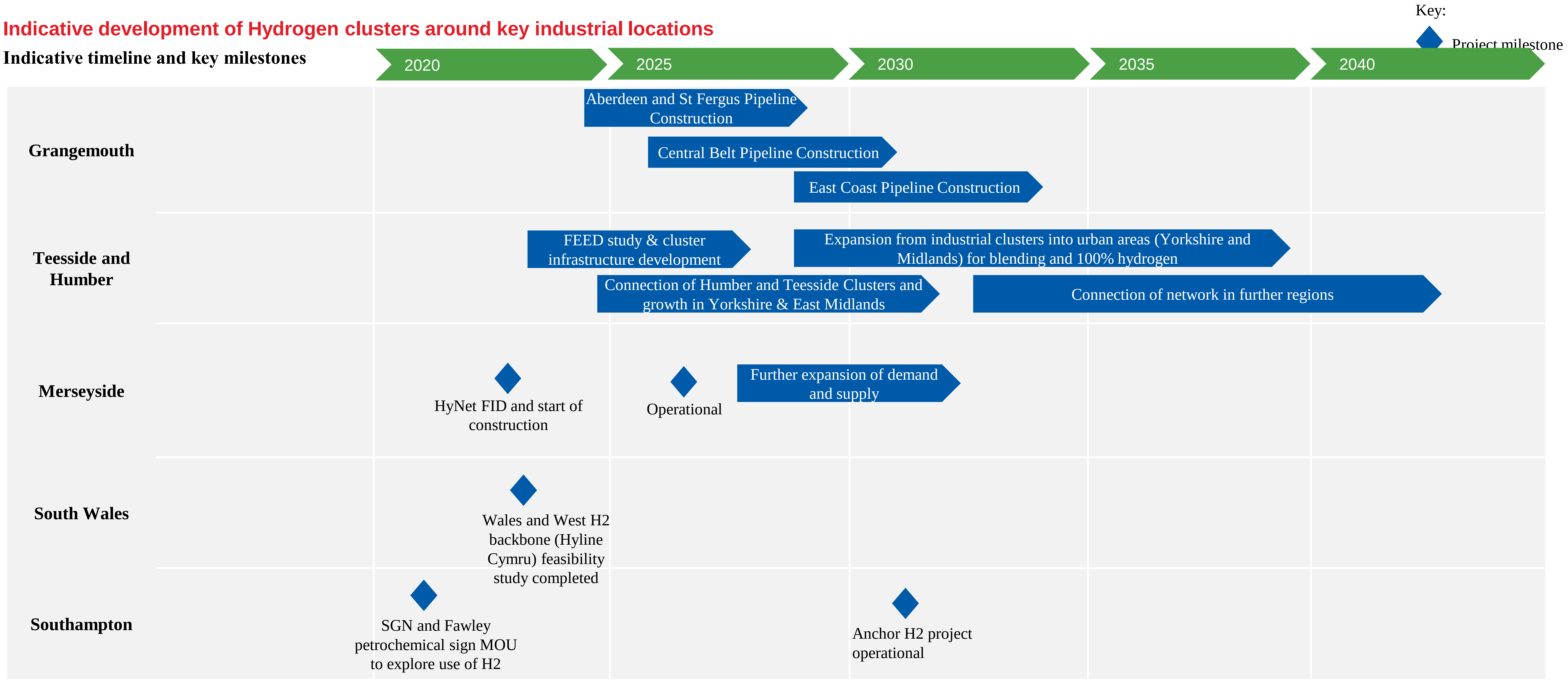
4.2 | Hydrogen clusters

Indicative development of Hydrogen clusters around key industrial locations

Indicative timeline and key milestones



Indicative timeline as of January 2023

4.2 | Hydrogen backbone

Development of a Hydrogen backbone

Overview

As the hydrogen supply and demand picture develops across the UK and Europe, Transmission network operators, interconnector operators etc. have been developing their thinking around build a hydrogen backbone, this is a series of high pressure pipelines to transport 100% hydrogen. This network will enable greater security of supply and additional market access to hydrogen.

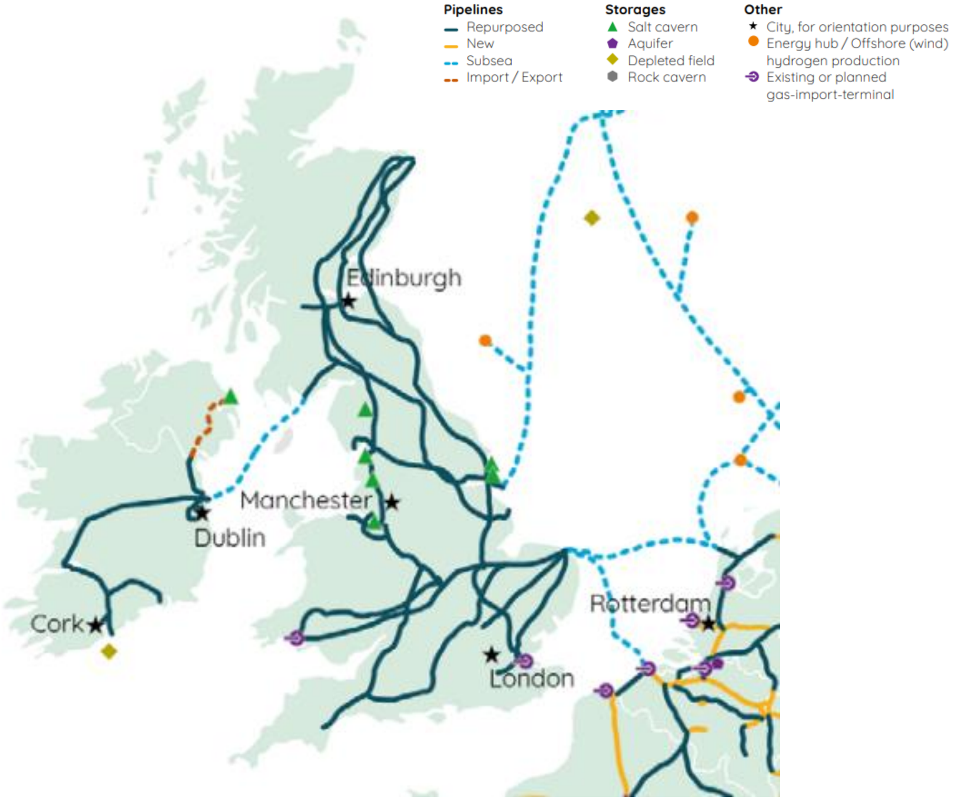
European Hydrogen Backbone

In April 2022, European Hydrogen Backbone (EHB) initiative, a group of 31 energy infrastructure operatives including National Gas Transmission, published its latest view of the European Hydrogen Backbone [13].

As presented in the map to right, the proposed European Hydrogen backbone in 2040 with European interconnection to GB at Bacton, Moffat and at Hull as well as the LNG terminal at Grain. It also indicates that the onshore network is fully repurposed with no new areas covered by the transmission network.

The initiative has also published five hydrogen supply corridors to support the delivery of the 2030 targets and hydrogen markets: North Africa & Southern Europe, South-west Europe & North Africa, North Sea, Nordic and Baltic regions and East and South East Europe [14].

These corridors will connect local supply and demand before then expanding to include export potential and joining up the corridors. In the North Sea this will connect blue and green hydrogen projects to support UK, Netherlands, Belgium and Germany. This is further discussed on the next slide.



2040 GB links to European Backbone

Source: European Hydrogen Backbone, April 2022

4.2 | Hydrogen backbone

Development of a Hydrogen backbone

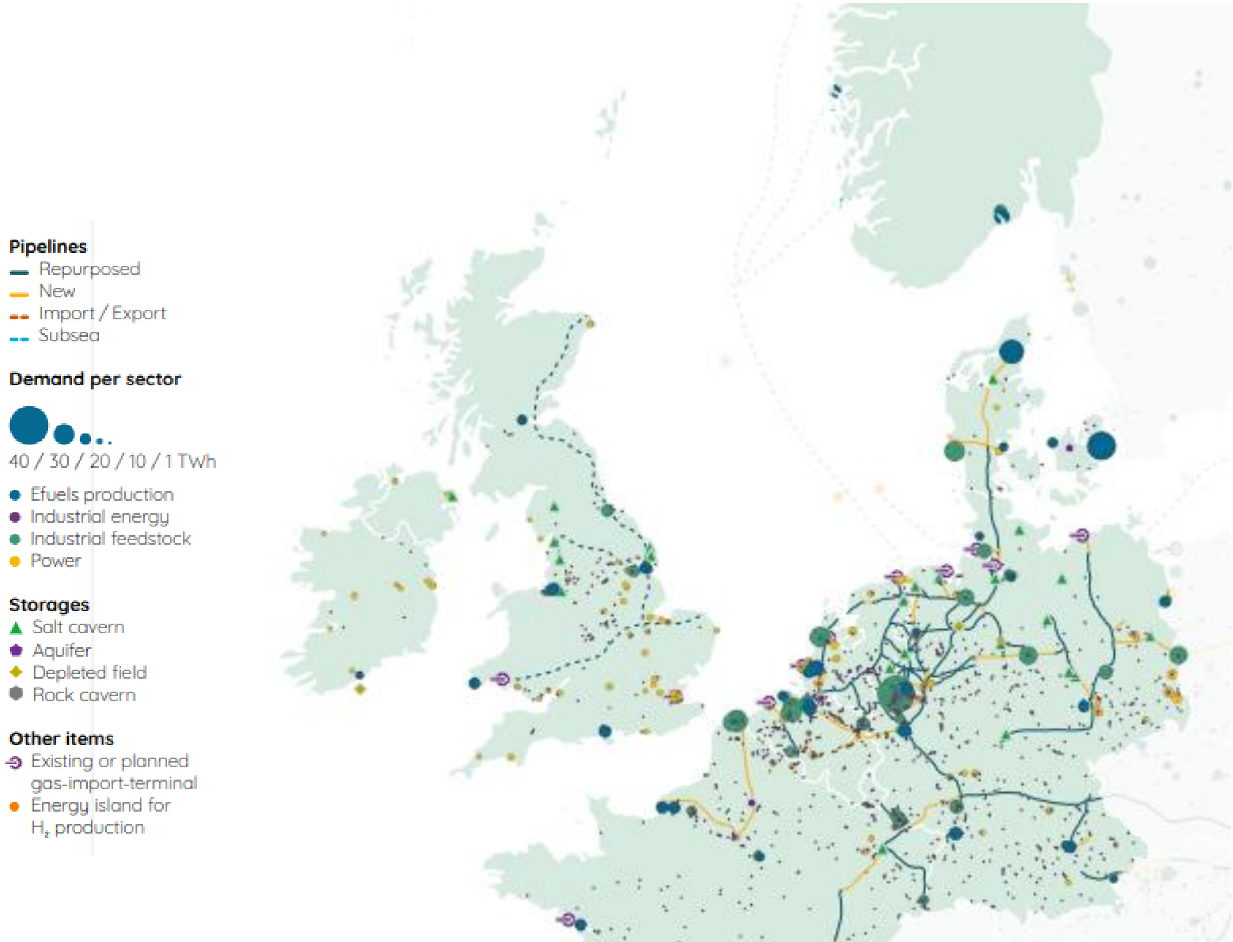
North Sea Hydrogen Corridor

The 2030 indicative maps detailing the supply corridors shows that the network will develop to connected the Northern clusters plus South Wales as well as Bacton on the East Coast.

For the North East Corridor the hydrogen network by 2030 would be 12,000km with 30% of those new pipelines.

This is based on a hydrogen supply of 250TWh of which 40% is blue hydrogen and the remaining split between grid based electrolysers and dedicated green (e.g. offshore windfarms). In the UK, the demand is 27TWh, with this predominately driven by demand from the industrial clusters.

In comparison to the FES scenarios demand, this expected demand is higher as Consumer Transformation (low hydrogen scenario) has a total hydrogen demand (excluding blending) of 2.8TWh, Leading the Way (balanced hydrogen scenario) of 16.2TWh and 14.36TWh in System Transformation (high hydrogen scenario).



2030 North Sea Corridor

Source: European Hydrogen Backbone, May 2022

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4.2 | Hydrogen backbone

Project Union

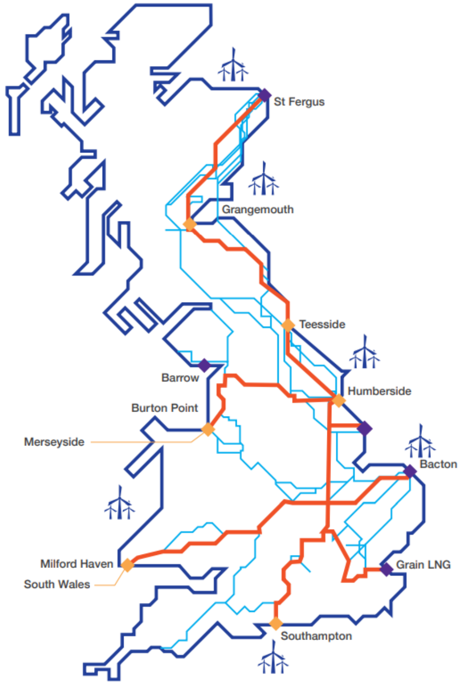
National Gas Transmission (NGT) are currently exploring a transition to 100% hydrogen via Project Union [12].

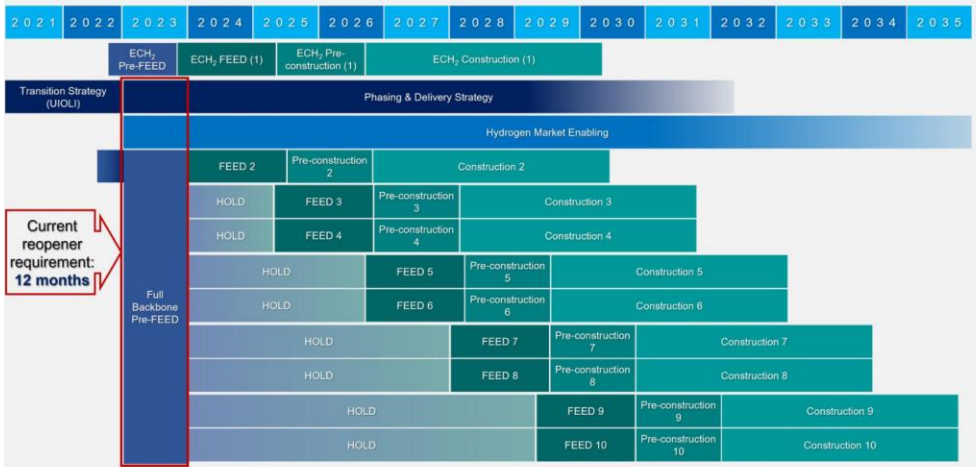
The backbone intends to connect hydrogen production, demand including the industrial clusters, storage and export centres. The routing described by NGT is defined as illustrative but is expected to capture the clusters (Grangemouth, Teesside, Merseyside, Humberside, South Wales and Southampton) as well as the strategic production sites of St Fergus, Barrow, Bacton, Theddlethorpe, Burton Point and Grain

NGT submitted a reopener to Ofgem to undertake a full backbone pre-front end engineering design which will then provide a proposed plan and detailed timelines for how the backbone should be developed. Ofgem have now responded to this and part funded. National Gas's pre-FEED study will focus in on specific sections of the hydrogen backbone and consider which pipelines can be repurposed and if any new assets are needed. A provisional roadmap for delivery is indicated opposite with first construction commencing in 2026 and continuing for a ten-year period. Based on the East Coast Hydrogen project, NGT expect East Coast to be the first area to convert.

Initial plans published by NGT suggest that the backbone would comprise 1,500 – 2,000km, which is approximately 20-25% of their existing network (7,660km). Public domain information does not indicate the demand capacity that will be supported by this hydrogen backbone.

In parallel, FutureGrid is undertaking the safety case for 2% blend, 5% blend, 20% blend and 100% hydrogen to inform an updated QRA and Safety Case. Having completed construction in 2022, the testing and updated safety case will be finalised by November 2023.





Project Union

Source: National Gas Webinar, December 2022

4.3 | Customer transition

Customer transition off natural gas

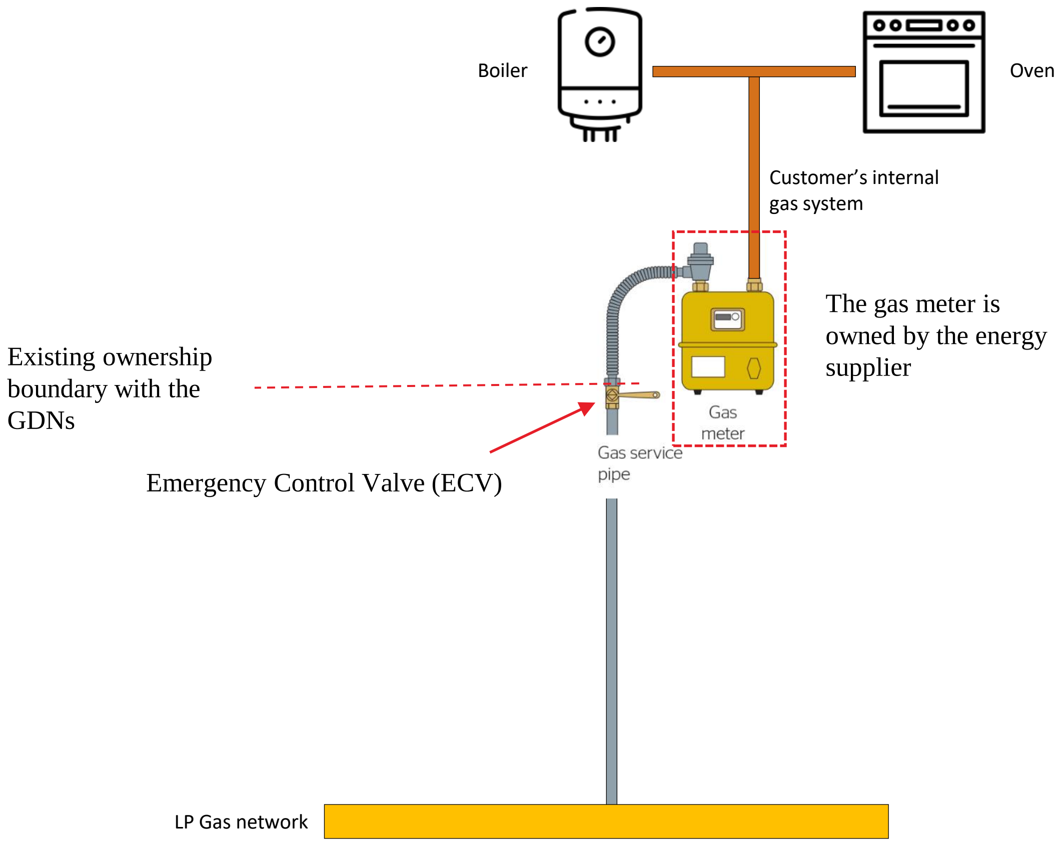
Overview

The customer experience is considered one of the key factors in this project, regardless of whether they use hydrogen or transition to another energy source. Given the importance of heating to a customer's welfare, conversion must be done with minimal disruption to the customer, with the potential for a customer to be without heating, hot water and an oven restricted to as little time as possible. The two options this report considers are the adoption of hydrogen and electrification.

Customer gas equipment

The diagram opposite shows the customer connection to the gas network and the various ownership boundaries for the key equipment:

- Customers are connected to the low pressure distribution network via a service pipe.
- An Emergency Control Valve (ECV) is located at the end of the service pipe, just in front of the gas meter. The ECV is owned by the GDNs and represents the ownership boundary between the GDN and the Customer.
- Immediately after the ECV, the gas meter is connected in order to accurately bill the Customer for their gas consumption. The gas meter is owned by the Customer's energy supplier.
- The Customer's internal gas system is then connected to the meter, transporting gas to the customer appliances e.g. boiler and oven.



Gas infrastructure around the customer premises

Source: Arup analysis

4.3 | Customer transition

Customer transition to hydrogen

Transitioning a customer to hydrogen

A safety evidence for hydrogen within detached, semi-detached and terraced homes has been generated by the Hy4Heat programme and several demonstration projects such as H100 and NGN's hydrogen homes [5]. SGN are currently undertaking a project to develop the safety case associated with multiple occupancy buildings.

Conversion process

The conversion process would typically involve the following steps:

1. Customer taken off gas by closing the ECV.
2. Customer system is purged to remove the residual gas in the customer system.
3. The Customer equipment is made hydrogen ready or replaced (boiler, cooker, meter) and tested.
4. The Customer is then reconnected to a hydrogen supply and their appliances relit.

There are a number of technical and logistical challenges associated with this process, which have significant implications for the speed of transition:

Customer appliances

- Existing customer appliances are not hydrogen ready, given they are designed to burn natural gas which has significantly different properties to hydrogen.
- Hydrogen ready appliance technology is currently in existence in order to support various hydrogen trials, however these are not currently available, nor in use in customers' homes today.
  - Via its Hy4Heat programme, Frazer Nash tested and developed domestic appliances which can safely use hydrogen as a fuel in providing heating, hot water and cooking requirements. Several boiler manufacturers such as Baxi and Worcester Bosch have developed prototype hydrogen boilers which have been installed in a testing facility in Spadeadam as well as a hydrogen site near Gateshead.
  - Some progress has been made for other domestic appliances. For example, Consortia is in the process of developing prototype hydrogen cookers and gas fires while Clean Burner Systems have demonstrated that hydrogen is a viable fuel for domestic fires.
- In order to transition to hydrogen, the appliances in the customer home would have to be replaced. This would either need to happen during the transition, or potentially ahead of time.
- If installed ahead of time, the equipment would need to be able to operate on natural gas in the meantime and then be able to switch to hydrogen in the transition process, either via swapping out some components e.g. the burners, or by having hydrogen compatible parts ready built in with a different set of connections.
- Note the marketplace for such equipment is in its infancy, with very little standardisation in approach. The project team see the strategic standardisation of this market as a key success factor in enabling the transition.

4.3 | Customer transition

The customer transition will be a phased approach

Hydrogen supply

- As outlined in the overview to this section, a transition must be done with minimal disruption to the customer with minimal time off gas supply.
- In order to be able to reconnect the customer in as short a timeframe as possible, the hydrogen supply is critical. The two options for this are either to build a brand new hydrogen system, or to re-use the existing gas system.
- In order to re-use the existing system and minimise the economic impact of the transition, the natural gas would have to be removed from parts of the existing system and replaced with hydrogen gas in very short timeframes.

New network needed for domestic conversion

- Several reports published by the network companies have discussed network conversion and how this will be delivered to ensure safe and secure supplies of natural gas and hydrogen in parallel.
- Similar conclusions have been reached by all the projects, that whilst further FEED studies are required to understand the detailed approach, new LTS network build out is required.
- The H21 North of England Report which considered the conversion of West Yorkshire concluded that the existing HP network would not be converted to hydrogen and the pressure reduction stations would be connected to a new hydrogen system [8]. The existing MP and IP network would be connected to the new hydrogen system.
  - For this to be possible, they state that some network engineering modifications would be needed to the pressure reduction stations with the design for this is likely to be site specific.
  - In terms of conversion, the MP network is separated into sectors and gradually converted from the natural gas network to the new hydrogen system.
- The North East Network and Industrial Cluster report which considered the conversion of Aberdeen, as detailed within the image, concluded that for the conversion to be possible the construction of a new 7 bar hydrogen pipeline would be needed to run in parallel to the existing 7 bar natural gas pipeline [3 and 16].
- Finally, the Wales and West Utilities Regional Decarbonisation Pathways has estimated the amount of new network that would be required is 600km of new LTS [7]. For the HP network, they estimate 60% new hydrogen assets will be required, approximately 30% for IP and then 10% for MP in a high hydrogen scenario.
  - WWU consider some of the existing network can be converted however further detailed modelling is required to understand the natural gas demand that will be required during the transition.

4.3 | Customer transition

Customer transition off natural gas to either hydrogen, or to electrification/other

Customer disconnection from the gas system and conversion to electrification

In the event that a customer is transitioning away from gas e.g. to a heat pump, their connection to the gas network will need to be made safe, and the associated equipment removed from their premises [4].

This process is currently well established for normal operations for the gas networks, as customers voluntarily transition away from gas to heat pumps or other alternative means. The typical process is as follows:

- The customer notifies their energy provider that they no longer require a gas connection. Note a standing charge is applicable for a gas connection, even if no gas is being used; hence customers are financially incentivised to disconnect from the network as soon as is practicably possible in the event they are transitioning.
- The energy provider would arrange for the customer to be non-permanently disconnected from the gas network, either using their own field force, or a sub contracted personnel.
- Using the ECV valve, the customer would be disconnected from the network, the meter removed and the ECV valve capped with a plastic screw cap.
- Under the current Pipeline Safety Regulation, the GDN has 12 months to come and make the disconnection permanent:
  - The GDN would cut and cap at the customer end of the service pipe, usually in the pavement or the driveway of the customer premises, with the service pipe left in situ.
  - The ECV and meter box would be removed (either from the outside of the customer premises or from inside the customer premises depending on the location of the meter).
  - The customer site would be remediated including reinstatement of the driveway / pavement from the capping, with any additional remedial works to the customer premise carried out (e.g. filling of holes, painting etc.)

Similarly, to the hydrogen conversion, there are a number of key challenges associated with this process in the context of this project:

Customer equipment;

- Given the social responsibility of the GDNs, a customer couldn't be disconnected from the gas network unless an alternative source of heating was available. This would require the customer to have pre-installed a heat pump and associated equipment.
- Whilst a detailed analysis was not part of this project's scope, energy efficiency standards would need to be addressed if heat pumps were deployed at scale. Most dwellings would also require new or alternative heating systems.
- In addition, any other gas-fed appliances e.g. ovens and hobs would also have to be replaced as part of this transition.

4.4 | Decommissioning the gas network

Decommissioning

Overview

In the event that Great Britain transitions away from gas to electricity, the existing gas system will become surplus to requirements.

Whilst there are a number of potential use cases to re-use lengths of pipe e.g. fibre ducting, conversion to water transport etc., this project considers the scenario that the network would require widespread decommissioning.

The Health and Safety Executive (HSE) oversee and regulate such activities in the UK, providing a framework to manage the risks associated with such an activity [15]. Considerations include the associated safety and environmental risks, as well as any legal and financial liabilities.

Whilst there is no specific guidance for decommissioning the entire gas system, the project team has drawn on its prior experience of such works in the UK, as well as engaged the HSE directly on the matter.

HSE guidance on decommissioning; Regulation 14 of the Pipeline Safety Regulations (PSR)

Regulation 14.1: “The operator shall ensure that a pipeline which has ceased to be used for the conveyance of any fluid is left in a safe condition.”

HSE’s corresponding guidance notes:

64. Pipelines should be decommissioned in a manner so as not to become a source of danger. Once a pipeline has come to the end of its useful life, it should be either dismantled and removed or left in a safe condition. Consideration should be given to the physical separation and isolation of the pipeline. It may be necessary to purge or clean the pipeline; due consideration should be given to the hazardous properties of any fluid conveyed in the pipeline or introduced during the decommissioning.
65. Depending on the physical dimensions of an onshore pipeline and its location, under the general provisions of the HSW Act, it may be necessary to consider the risk of the pipeline corroding and causing subsidence or acting as a channel for water or gases.

Conclusions

Whilst the HSE and PSR outline regulations to cover decommissioning, the decommissioning outcome is a broad spectrum – ref: guidance note 64 “Once a pipeline has come to the end of its useful life, it should be either dismantled and removed or left in a safe condition”.

Given the scale to decommission the whole network of the undertaking, the project team consider Government would likely issue a specific set of guidance notes, accounting for context. A similar approach has been taken with regard to the decommissioning of Offshore Oil and Gas Installations and Pipelines.

The project team also consider that in the event the networks are decommissioned, there is likely a need for an entity to remain in order to maintain site security and hold the ongoing legal liability associated with the remains of the network. An example of this is the Coal Authority.

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4.4 | Removal of natural gas from the system

Removing the natural gas from the system

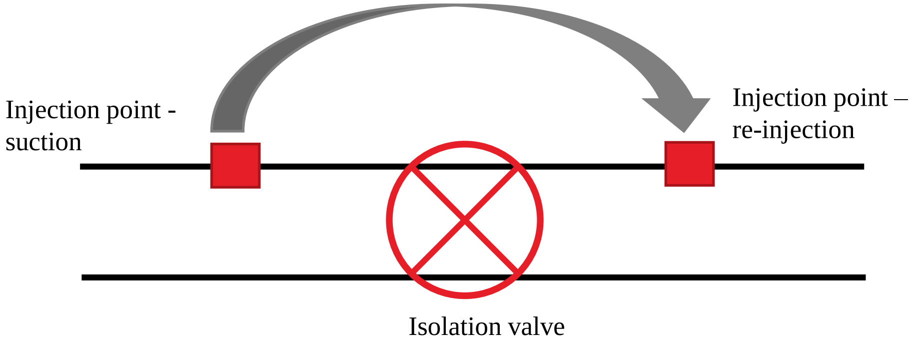
In any future scenario, natural gas must be removed from the system before either injecting hydrogen or decommissioning the network. Current convention is to flare residual gas when purging the system, however for the scale of this exercise, the value of the residual gas and the carbon impact of flaring drives a requirement for an alternative solution.

The project team and stakeholder group considered that the most efficient way of achieving de-energisation would be to 'push' the gas back up the pressure tiers i.e. out of the low pressure, up through any medium and intermediate pressure to the LTS and then eventually into the NTS. The group asserted this was likely to be achieved using similar techniques to current live works, using gas recompression rigs:

- Identify strategic points in the network to achieve deenergising with the fewest possible interventions; PRSs and District governors are likely such places, because they can be easily isolated and link the lower pressure network.
- If required, install an isolation valve and 2 injection points, one for suction, the other for injection, as per the diagram opposite, bottom.
- Use recompression rigs to withdraw gas from one side of the valve and reinject into the network the other side of the isolation valve, thus removing the natural gas from the downstream network and pushing it back up the pressure tiers.

Mobile recompression equipment

Source: National Gas Transmission, PMC



Mobile recompression explanation

Source: Arup

5 | Scenarios

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5 | Scenarios

Section overview

This section of the report details the project's approach to developing the scenarios that describe the possible future state of the energy market in Great Britain.

As part of this project's core aims, the outputs of our work was intended to be easily digestible, thus steering the project team towards using scenarios that were available in the public domain, with a good degree of industry understanding and stakeholder recognition.

Once a set of scenarios were chosen, the project team verified the key assumptions within, in order to align to the overall aims and objectives of the project.

Section Navigation

- Review of publicly available scenarios
- A detailed description of the Future Energy Scenarios (FES)
- Summary

5.1 | Publicly available scenarios

Energy scenarios

In the UK, there are a range of public bodies and private companies that develop and publish energy scenarios. These energy scenarios are intended to model the future demand for various energy types including natural gas, hydrogen, electricity etc. as well as the future supply side and electrical generation technologies.

The project team considered three possible scenarios sets that already existed in the public domain and had a good degree of industry support. These scenarios are as follows:

- As part of its Sixth Carbon Budget, the Climate Change Committee (CCC) published a range of possible pathways or scenarios.
  - In the time period between publishing (December 2020), industry views have evolved. This is because industry views are constantly evolving as new evidence becomes available e.g. Hy4Heat report [3]. The project team have used information gathered from the stakeholder period during Q1 2023.
- In 2020, Arup undertook a study for the Scottish Government where we developed a range of possible hydrogen deployment scenarios for Scotland.
  - These scenarios were not developed at a National level, hence considered inappropriate for this study.
- In Great Britain, National Grid's FES (Future Energy Scenarios) are often the most widely referred to and are generally considered to provide a holistic view of energy system pathways.
  - The FES is published on an annual basis, with significant industry stakeholder engagement and buy in.
  - The FES is used by many network operators as the basis for their forecasting models.

In summary the project team consider the FES to be the most appropriate set of scenarios for use in this project.

Publicly available energy scenarios

Source: National Grid, Scottish Government, Climate Change Committee

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5.2 | The FES in detail

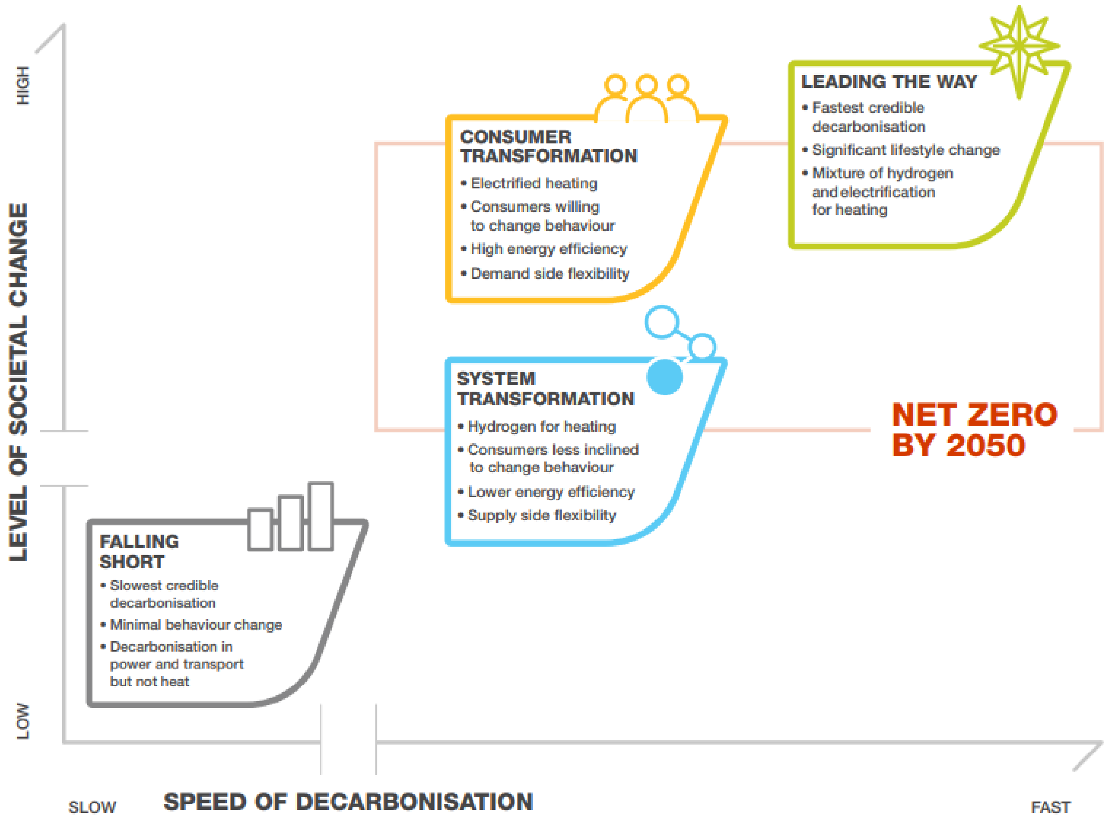
National Grid FES 2022

Every year, National Grid ESO publishes its Future Energy Scenarios, which set out four potential pathways for how the energy system could evolve, looking at both consumer led and system led drivers.

In developing the scenarios, the ESO engages with over 1,000 stakeholders across the industry, with the outputs used for a whole range of regulated activities, e.g. Network Options Assessment (NOA), Electricity and Gas Ten Year Statements, price controls etc.

The modelling results in four credible scenarios:

- "Leading the Way" is the most ambitious pathway, meeting net zero by 2047, with high levels of consumer engagement and decarbonisation from electrification and a shift to hydrogen.
- "System Transformation" which achieves net zero by 2050, via a different technology and change driven by the system vectors.
- "Consumer Transformation" achieves net zero by 2050, via different technology, and change driven by consumer vectors.
- "Falling Short" is the least ambitious scenario, and does not meet net zero 2050, with a heavy reliance on natural gas.
- As the scenarios for the project were required to meet net zero 'falling short' is not considered further.



National Grid ESO Future Energy Scenarios

Source: FES [29]

5.2 | The FES in detail

National Grid FES 2022

“Leading the Way”

- Under the Leading the Way scenario, Net Zero is driven through high levels of consumer engagement.
- This is assumed to be the fastest credible pathway to net zero, achieving it in 2047.
- This results in significant lifestyle changes for consumers, with a mixture of hydrogen and electrification for heating.
- Energy efficiency initiatives drive down demand, with significant retrofitting (insulation and double grazing) of housing stock.
- Combination of green and blue hydrogen is used to decarbonise some of the more challenging sectors, for example industrial processes. Hydrogen production develops initially in and around the clusters, with hydrogen boilers focussed around those areas.
- Some small natural gas demand for methane reformation in the industrial clusters.

“System Transformation”

- Under the System Transformation scenario, Net Zero is achieved through significant changes on the supply side, with consumers experiencing more limited change than CT.
- Hydrogen is widely used for heating homes and in industrial processes, but also aviation and shipping, transport, export.
- Areas closer to current natural gas network are likely to have higher concentrations of hydrogen boilers.
- Majority of the hydrogen produced from natural gas with CCUS, however a considerable amount of green hydrogen also produced through electrolysis.
- Under this scenario, significant levels of hydrogen storage required by 2050, with over 40GW of network connected electrolysers.
- Considerable demand for natural gas remains for use in methane reformation processes.

“Consumer Transformation”

- Under the Consumer Transformation scenario, Net Zero is driven through high levels of consumer engagement.
- This is seen as a high electricity scenario with high levels of energy efficiency and demand side flexibility, with a smaller role for hydrogen.
- Electrified heating with consumers providing flexibility to the grid through demand side response and smart energy management.
- High levels of grid storage, combined with demand side response reduces peak demand.
- Hydrogen production develops around industrial clusters, with industrial users unable to electrify moving to clusters.
- No further hydrogen distribution network.
- Some small natural gas demand for methane reformation in industrial clusters.

“Leading the Way” Hydrogen supply and demand

2050 Hydrogen Demand	Blue Hydrogen Production	Green Hydrogen Production
244 TWh	26 TWh	179 TWh

“System Transformation” Hydrogen supply and demand

2050 Hydrogen Demand	Blue Hydrogen Production	Green Hydrogen Production
431 TWh	218 TWh	160 TWh

“Consumer Transformation” Hydrogen supply and demand

2050 Hydrogen Demand	Blue Hydrogen Production	Green Hydrogen Production
114 TWh	1 TWh	104 TWh

Source: FES [29]

5.2 | The FES in detail

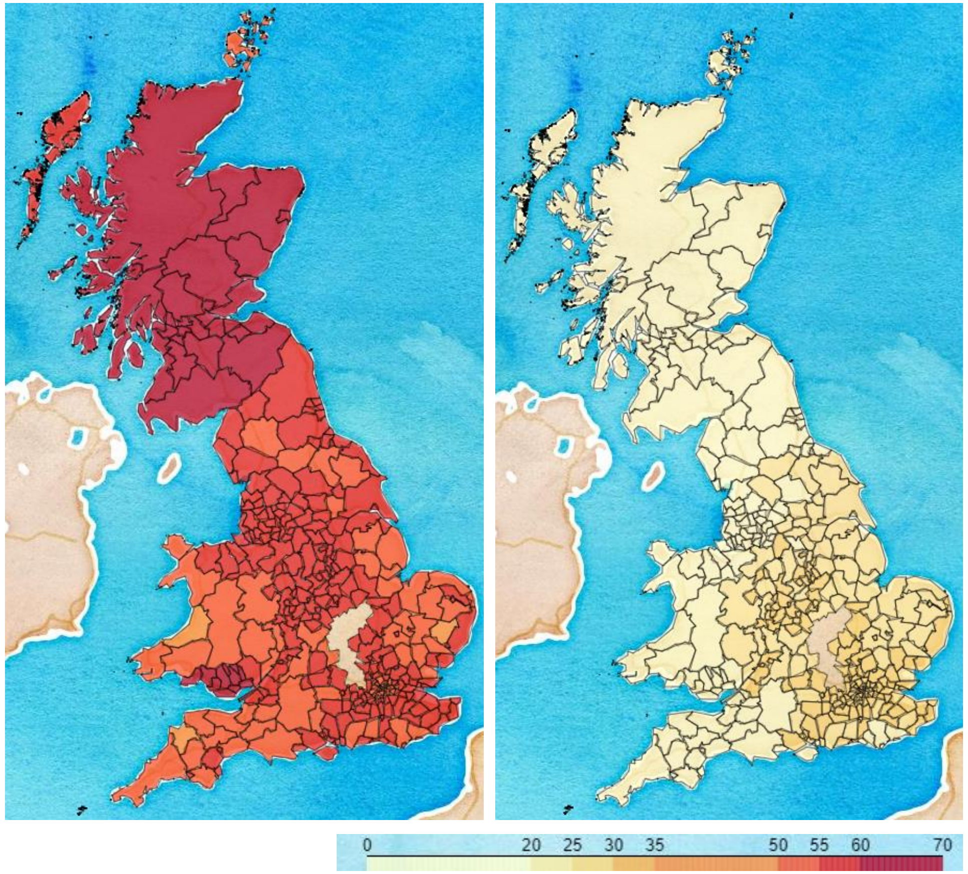
2050 end states

FES provides an indication of the deployment of hydrogen technologies in 2050. The far-right map is provided for context as to where there are currently homes connected to the gas network as it is unlikely that homes that are not currently connected to the gas network would convert to hydrogen.

As indicated by the maps, System Transformation has significant deployment of hydrogen boilers and hydrogen hybrid heat pumps with on average over 50% of homes having hydrogen solutions. In particular, Scotland has on average over 65% deployment and Wales over 58%.

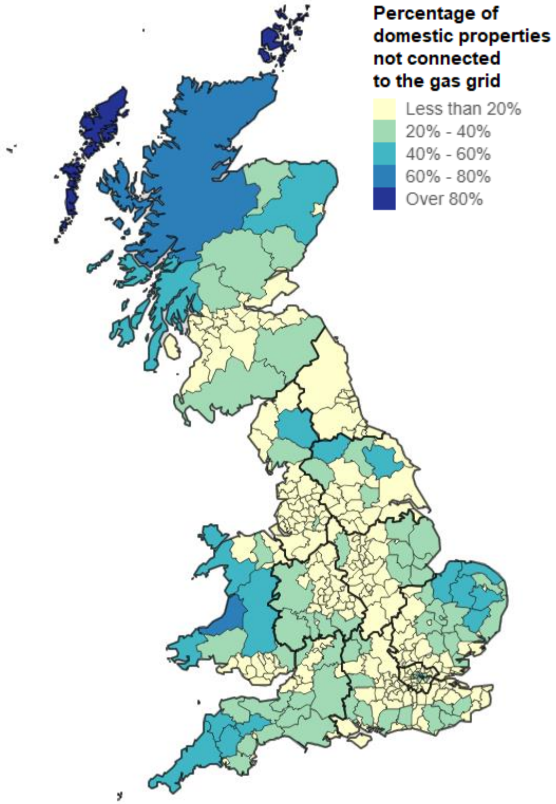
In the Leading the Way Scenario, Scotland has 1% deployment of hydrogen appliances and Wales on average has 5%. Highest deployment is in the Midlands and South East (including London). The top 5 highest deployment areas: City of London, Southampton, Slough, Hammersmith and Fulham and Reading. Noticeably, this demand is, with exception of Southampton, further away from the industrial clusters.

The FES scenarios assume an even penetration of hydrogen domestic heating demand across GB in the scenarios i.e., they have not made any significant regional variation in where hydrogen is deployed. For the purposes of the network modelling scenarios, this assumption was modified to reflect that in the Balanced and Low scenarios, a widespread network would not remain, and that demand would be concentrated near the industrial clusters. See Section 6.3 for more details.



Percentage of homes with hydrogen in 2050 in System Transformation (left) and Leading the Way (right)

Source: FES & Arup Analysis



Percentage of domestic properties not connected to the gas grid

Source: BEIS Subnational Consumption Data

5.3 | Summary

Conclusions

The FES scenarios closely align with the project team's views on the current trajectory of the Great Britain energy industry. With strong stakeholder support, our own stakeholder engagement has been supportive of our choice of scenarios.

This project aims to provide a range of potential outcomes that explore how the gas system could look by 2050. To this end the project team has decided to adopt a high, medium and low scenario, aligning to the FES as follows:

- High – System Transformation.
- Balanced – Leading the Way.
- Low – Consumer Transformation.

Assumptions and caveats

As per the project scope, this study is intended to be a top down view of gas system transition scenarios, rather than a detailed review of associated challenges. As a result the following assumptions and caveats have been made:

- Affordability implications of the scenarios will not be considered; a technical methodology was developed and tested the stakeholder group, before being costed. This project aims to be technically-led rather than affordability-led.
- All scenarios achieve Net Zero (hence the exclusion of "Falling Short")
- The project assumes a highly-enabled market context, where the energy networks are able to efficiently carry out the transition under the challenging timeframes. Hence, it has not considered the extent to which the scenarios are achievable within the context of technology readiness, supply chain and skill constraints.
- The scenarios explore 100% hydrogen only, with interim hydrogen blending excluded from our analysis.
- The FES scenarios achieve an even penetration of hydrogen domestic heating demand across GB i.e. they have not made any significant regional variation in where hydrogen is deployed. For the purposes of the network modelling scenarios, this assumption was modified to reflect that in the Balanced scenario, a widespread network would not remain, and that demand would be concentrated near the industrial clusters.

6 | Transition methodology and modelling

6 | Transition methodology

Overview

This section details the Transition methodology chosen for this project. The methodology builds on the established evidence base, as well as reflecting discussion held with industry stakeholders.

Note a transition methodology was developed in line with the aims and scope of this project, resulting in a top down approach. With support from the stakeholders, the project team have sought to characterise the networks at a National system level, and apply assumptions accordingly.

As per our stakeholder engagement, the project team anticipate there will be discrete parts of the network that would likely challenge aspects of our proposed methodology from a bottom-up perspective.

However, given the project's scope and timelines, the project team consider the top down approach justified given the parameters; this project is intended to provide a view of the transition scenarios, that can be applied in a top down transition methodology.

Section navigation

- Technical network assumptions; summary of the conclusions and assumptions regarding the hydrogen readiness of the individual network assets, as well as any operational assumptions made.
- Customer transition approach; detailed description of the approach taken to transitioning customers either to hydrogen or disconnecting customers from the network.
- Network decommissioning assumptions; detailed description of the likely scope and approach decommissioning.
- Scenario-specific transition methodology for each of the high, balanced and low scenarios:
    - High-level description of the scenario assumptions and assumed timeframes
    - Key transition decisions / assumptions that were made by the project team
    - Visual step-by-step guide to the transition

6.1 | Technical assumptions

Assumptions made regarding the hydrogen readiness of network components

Overview

As detailed in Section 4 of this report, the degree to which hydrogen will impact various network components is uncertain. Furthermore, very little of this theory has been applied practically to the existing network components, therefore has not yet been approved by the HSE.

As a result the project team have had to make a number of assumptions; the project team anticipate the findings and conclusions of this work was determined based on best available evidence at the time of writing and can be updated by the reader to incorporate the latest evidence from the industry.

Pipeline

The base for pipeline readiness is relatively well advanced:

NTS:

- As per discussions with NGT, and their preliminary work carried out to date, and the wider findings across Europe, the majority of the NTS (80%) is considered suitable for hydrogen, given the grade of steel used (various steel grades).
- Therefore, 20% of the network is assumed to be unsuitable for hydrogen; 11% as a result of the higher grade steels used in construction, and 9% as a result of existing condition defects.

LTS:

- All of the LTS is constructed in steel grades that are compatible with hydrogen.
- Given the comparable age, integrity management systems and operations of the LTS with the NTS, it was considered prudent to assume there would be a comparable portion of this network with existing condition defects. Therefore 9% of the LTS is assumed to be unsuitable as a result of condition defects.

Distribution pipelines:

- PE pipelines are considered to be hydrogen ready, as demonstrated by various studies to date.
- Iron (spun, ductile etc.) is considered to be unsuitable for hydrogen, as per discussions with the HSE.
- Low pressure steel is constructed from low grade steel and therefore considered to be hydrogen ready.
- Services; any non-PE services are considered unsuitable for hydrogen.

Compressor

Given the different characteristics of natural gas and hydrogen, it is widely accepted that existing compressors are not suitable for 100% hydrogen. There is some discussion regarding the modification of compressors to accept hydrogen, however very little evidence is in the public domain.

As a result, the project team have assumed that all of the existing compressor fleet is unsuitable for hydrogen. Given the known age profile of the existing compressor fleet (with 5% currently under 10 years of age), modification is not considered economically sensible.

Pressure reduction equipment

There is very little evidence base regarding the hydrogen readiness of existing pressure reduction assets, however some OEMs assert that newer equipment is compatible. Whilst these assertions have not been verified, the project team's technical understanding of the likely challenges have resulted in the following assumptions being made:

- All PRSs, Governors etc. with a build date from 2020 onwards are assumed to be hydrogen ready with minor modifications (assumed to include removal of heating equipment, recalibration of instrumentation, replacement of non hydrogen ready soft parts, valve seats etc.)
- Equipment with a build date earlier than 2020 are considered unsuitable for hydrogen.

For modelling purposes, the project team has used an assumed asset life of 30 years to calculate the proportion of equipment that would either need to be modified or replaced.

6.1 | Technical assumptions

Operational considerations for hydrogen

Requirement for a Hydrogen backbone

In all the FES scenarios, an underlying assumption is that industrial demand for hydrogen starts in the early 2030s in clusters, before spreading beyond the clusters from 2035 onwards. In order to provide security of supply to these industrial customers, accommodate larger energy demands and reduce the barriers to entry for hydrogen production, a hydrogen backbone is likely to be required.

- Given the requirement to link the industrial clusters, the project team have assumed the scale of the backbone to represent 20% of the existing NTS, in order to provide the necessary geographical coverage.

Furthermore, the project team understand that this backbone will need to extend down into the ownership boundary of the GDNs as a hydrogen LTS backbone in order to facilitate a transition to hydrogen with a time period of parallel high pressure hydrogen and natural gas networks. This will enable major industrial customers to connect to hydrogen and facilitate the overall transition. This is supported by many other studies, most notably Wales and West Utilities (WWU) Regional Decarbonisation Pathways [7].

- The scale of this backbone is considered to vary amongst the scenarios, with the High scenario requiring the largest LTS backbone, and the Low scenario requiring the smallest.
- The project team have assumed LTS backbone requirements of 40%, 30% and 20% of the length of the existing LTS for the High, Balanced and Low scenarios respectively.
- Given the existing configuration of the NTS, and the existing network capability of the NTS (including capacity), it is not considered possible to create a hydrogen backbone of sufficient geographical coverage, with the existing asset in the required timeframes (2035) for the following reasons:
  - Hydrogen and natural gas systems would need to be independent i.e. no co-mingling;
  - Both systems would be required to meet the 1 in 20 peak demand and provide security of supply to customers;
  - The hydrogen system would need to have significant coverage of GB, in order to transition industry; and,
  - NGT's plans for a hydrogen backbone are to connect industrial clusters and industry outside of clusters.
  - Natural gas demand is not forecast to reduce sufficiently in the short term, to increase network capability of the NTS to the point that it can be split into 2 independent systems, both of which are capable of meeting the 1 in 20 peak demand.

Hydrogen backbone – conversion or new build?

A key factor in this determination is the need to provide a resilient security of supply to customers. The NTS is sized to meet the 1 in 20 peak day demand and ensures the security of supply for gas demand (including gas fired electrical generation).

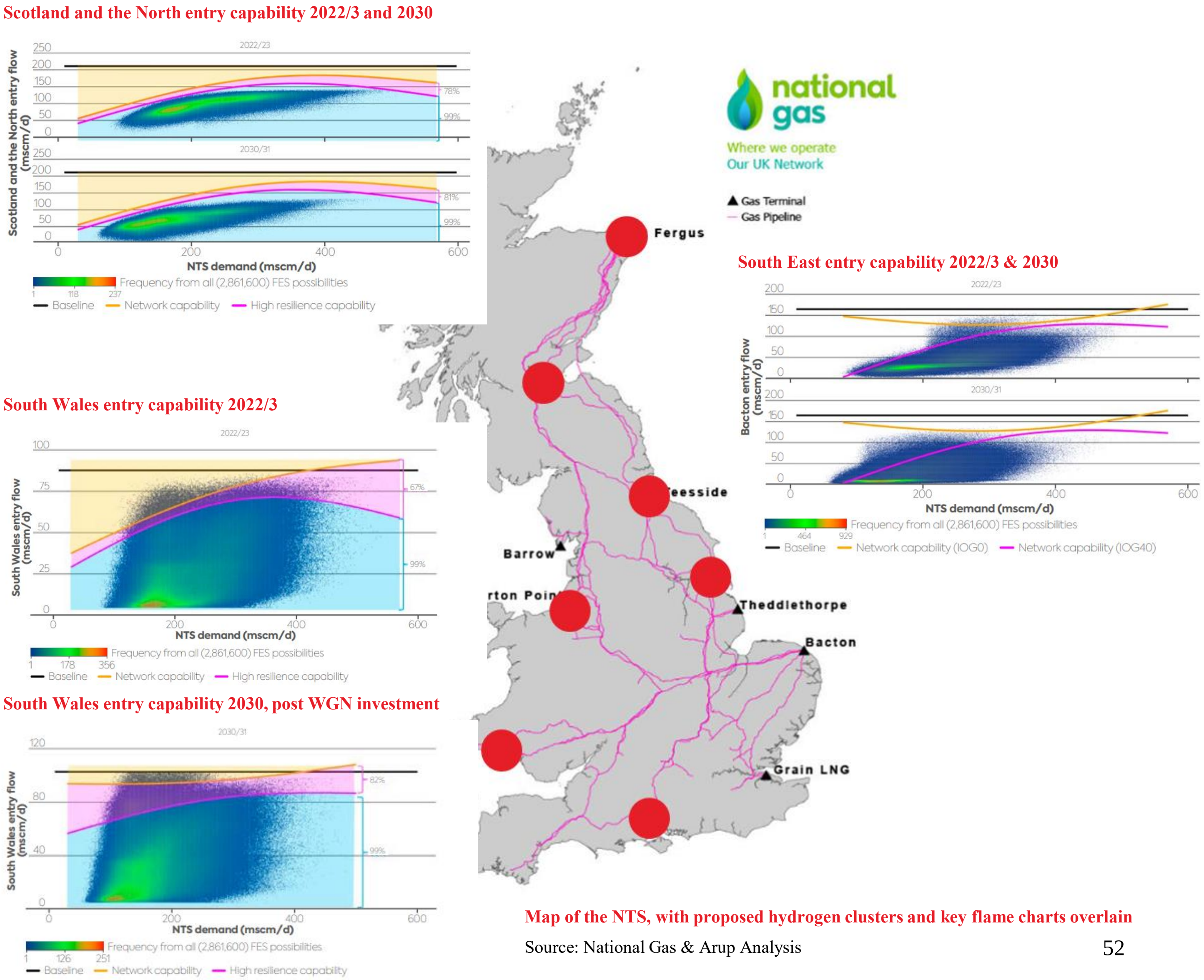
- The 1 in 20 peak demand is a statistical forecast of demand that could be expected for the whole country on a very cold day; it would be exceeded in one out of 20 winters.
- In order to ensure the ability of the NTS to meet this peak demand, NG apply a resilience standard that ensures their Peak supply (n-1 largest loss), exceeds the 1 in 20 peak demand. This peak supply (n-1 largest loss) assumes the loss of the single largest piece of NTS infrastructure.
- Additionally NG calculate their 'network capability', a function of the volumetric capacity of the network, the compression design and entry and exit flows. This capability is then compared to FES gas flows to ensure the NTS continues to be fit for purpose. The results of this analysis are published annually in the Annual Network capability Assessment Reports (ANCAR) [32].

6.1 | Technical assumptions

Operational considerations for hydrogen

Hydrogen backbone – conversion or new build? Cont'd

- The diagram opposite presents a diagram of the NTS, with the proposed hydrogen cluster locations overlain. As seen in the diagram, the NTS is a relatively simple network, designed to move gas around GB from the 7 injection points / gas terminals from North to South, East to West.
- Given its nature as a trunk line asset, the NTS is relatively linear with minimal meshing. In some instances, multiple runs of pipeline have been lain to increase network capacity e.g. from St Fergus down the East coast of Scotland, to increase the network capability.
- The ANCAR reports use flame chart analysis to compare the network capability of the NTS with the current and forecast energy flows. Given where the majority of gas enters the system, the St Fergus, Milford Haven (Herbrandston) and Bacton / Isle of Grain gas terminals are of particular importance.
    - The flame chart for Scotland and the North, presented opposite, demonstrates the high resilience capability is just above the flame in both 2022/3 and 2030.
    - The flame chart for South Wales significantly exceeds both the network capability, indicating that despite the double run of pipeline, demand exceeds network capability. In 2030, despite upgrade investment, the flame still exceeds the network capability.
    - The flame chart for South East is slightly more complex given how flows from Bacton and Isle of Grain impact each other however the ANCAR report summarises that there is sufficient entry capability for flows only from Bacton; if Isle of Grain flows are also high, it is not possible to maintain Bacton flows.



Map of the NTS, with proposed hydrogen clusters and key flame charts overlain

Source: National Gas & Arup Analysis

6.1 | Technical assumptions

Operational considerations for hydrogen

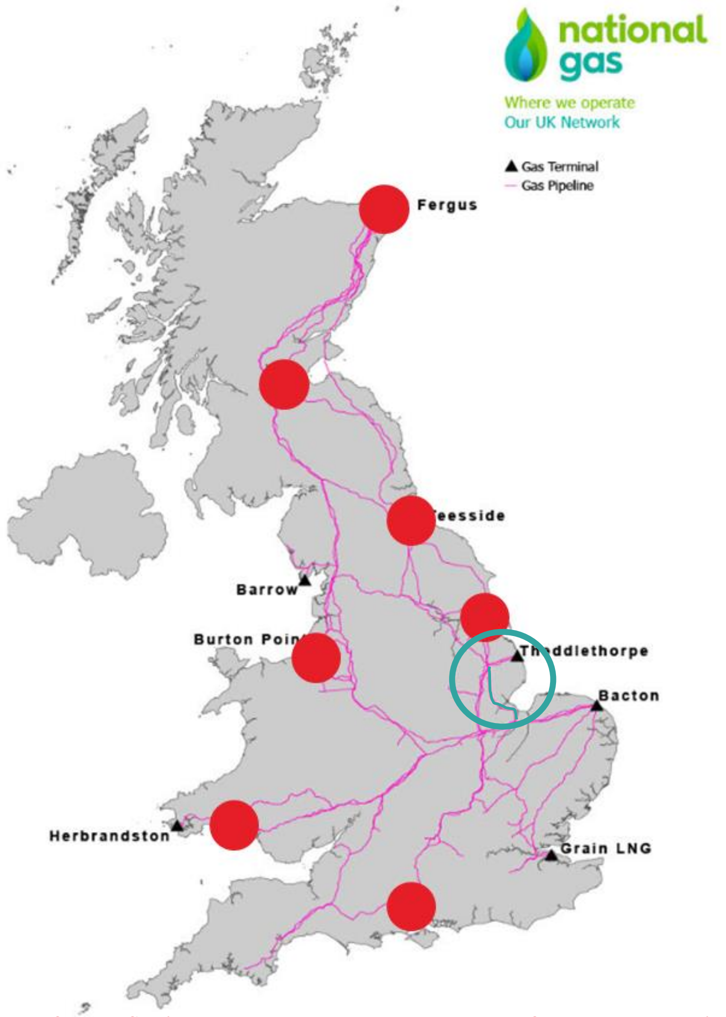
Hydrogen backbone – conversion or new build? Cont'd

In summary the ANCAR report analysis demonstrates that even with the forecast reduction in gas flows by 2030, forecast gas demand closely matches or exceeds network capability for the three key parts of the network.

In consideration of this, and the overall trunk line design, this Project considers that there is insufficient network capability in 2030 to allow the NTS to remove 2,000km or c. 25% from the natural gas system, and create the initial hydrogen backbone from repurposed NTS.

This project considers the initial hydrogen backbone would need to be a new build asset, that could then integrate sections of the NTS as and when the network capability allowed. This new build asset would allow for security of supply across both gas systems. Once major industry is transitioned in the mid 2030s, this will free up significant capacity on the natural gas system, enabling greater network flexibility to either transition customers onto hydrogen, or decommission areas of the network.

Whilst we are aware of the work currently being carried out by NGN and the potential repurposing of NTS's Feeder 7 (existing NTS natural gas pipeline, highlighted in blue on the diagram opposite), the project team consider that at a system level, a new build hydrogen backbone at both NTS and LTS levels is required to kickstart the transition. Once major industry is transitioned in the mid 2030s, this will free up significant capacity on the natural gas system, enabling greater network flexibility to either transition customers onto hydrogen, or decommission areas of the network.



Map of the NTS, with proposed hydrogen clusters and key flame charts overlain

Source: National Gas & Arup Analysis

ARUP

6.1 | Technical assumptions

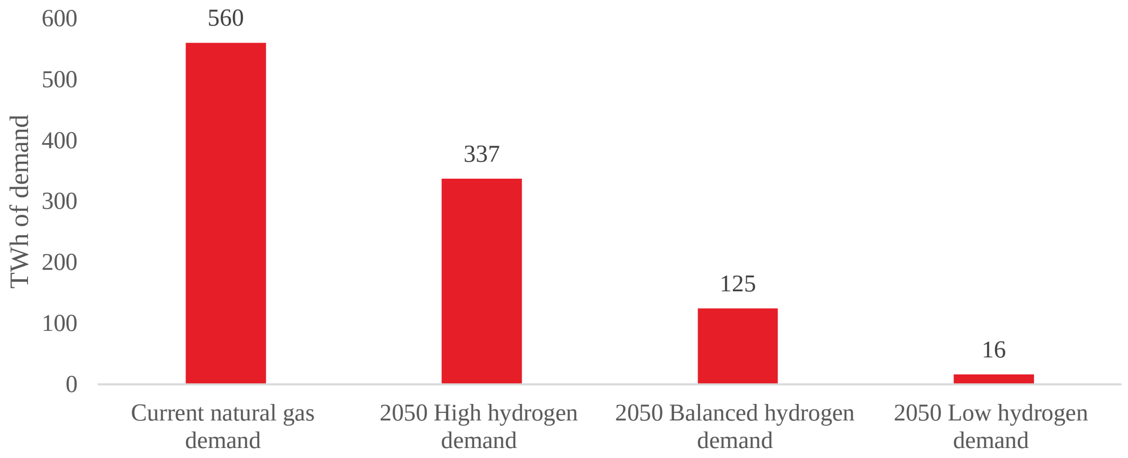
Operational considerations for hydrogen

Managing the difference in volumetric density of hydrogen

As described in Section 4 of this report, hydrogen's volumetric density means that in order to deliver the same amount of energy as natural gas, the network will need to deliver approximately three times by volume. However, because hydrogen has a lower viscosity than methane, the pressure drop for hydrogen is less than for methane. This means that substantial parts of the current network is broadly sized appropriately for hydrogen, although the gas moves more quickly in it.

The project team aim to mitigate this issue using a combination of factors, as discussed below:

- As per the chart opposite, in all of the scenarios considered, 2050 hydrogen demand is lower than the current natural gas demand, driven by energy efficiency measures and electrification.
- As described earlier in this section, the project team have assumed that new build hydrogen backbones will be installed at the NTS and LTS levels, thereby increasing the capacity of the network.
- As per Section 4 of this report, additional compression is assumed to be required at the NTS level, in order to mitigate pressure drop and maintain NTS pressure and flow rates. For the purposes of this study, an additional 50% of the existing number of compressor stations; one new station built between 2 existing stations.
- In the distribution layer of the network, all of the iron mains will need to be removed and replaced with PE, as per HSE's guidance. This will allow the GDNs to raise the operating pressure of the LP network.



Comparison of current vs future energy demand on the gas system

Source: National Grid ESO, Future Energy Scenarios

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6.2 | Customer transition

Network segmentation

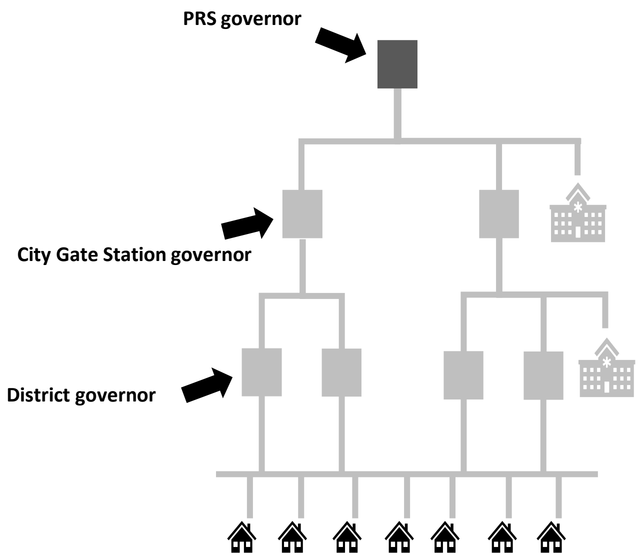
In any scenario, the gas network will have to be segmented in order to facilitate a transition to hydrogen, or decommissioning. Network studies to date have considered a variety of options including the specific conversion of Aberdeen (by North East Network and Industrial Cluster) and the conversion of West Yorkshire (H21 study [8]).

Driven by our top down approach, the project team have used network equipment as a proxy for segmentation in reality these will vary in size, and then assumed remaining network infrastructure which results in the below averages for GB:

- Using PRS infrastructure as a proxy for a network segment, the project team have identified 1,380 network segments in total (1 per PRS).
- Per segment there are 16 district governors and 59 service governors for further pressure reduction and management.
- Each segment contains 193 km of distribution main (a mix of IP, MP and LP), with 303 valves – this is equivalent to a valve every c. 600 m.
- Per segment there are 17,600 customers, equivalent to a small to medium sized town. This will be used as a 'typical stack' for the purpose of modelling.

The project team consider this approach enables the entire GB gas system to be modelled effectively from a top down perspective. Additionally, the segment size in terms of customer numbers, draws parallels to the Town Gas conversion, which achieved a similar pace of transition to what is described in the FES. In the event that a smaller segment size was required, it is likely that additional new build infrastructure would be required to take the hydrogen down a layer in the distribution network.

This network segmentation is used to drive our transition methodology across all scenarios, as well as enable a uniform way to model the cost implications. This will be referred to in some parts as 'de-meshing'.



Network segment illustration

Source: Arup

6.2 | Customer transition

Customer transition assumptions

In developing the transition assumptions, the project team has imagined a highly-enabled, centrally led approach to transition, with the necessary financial support to customers. Given the scale of the challenge, and the timescales required, the approach needs to draw heavily on the learnings from the Town Gas transition.

Conversion to hydrogen

The transition works will occur in the summer months (defined as April to September) when demand for gas is much lower (providing greater network flexibility), and the materiality of customers going off gas is lower (customers may have to forgo a shower on a hot day, as opposed to heating on a cold day).

The project team has assumed customers are off gas for a maximum of 48 hours. As the transition is occurring in the summer months, it is not anticipated that heating will be an issue for customers, however many will be without hot water and cooking appliances.

- 48 hours is considered the minimum time required to transition network segments in this methodology.
- The provision of welfare facilities, whilst not considered to be a mandatory requirement by the project team (given the time of year, short duration off gas and likely availability of alternative options), should be considered as part of ongoing research.
- Given the scope of this project, provision of welfare facilities has not been modelled, given it is not covered under the current obligations of the GDNs.

Prior to any works beginning, all customers in the segment will be screened to confirm their appliances are hydrogen ready. Note this is to be carried out by a centrally led organisation rather than the GDNs given the staffing requirements and the ownership boundary of the GDNs. The series of works required will include the following steps:

- 24 hours prior to the transition, GDNs will set up recompression equipment at the PRS and the 16 district governors (see page overleaf for a detailed explanation).
- Next the GDNs will take all the customers in the segment off gas (the assumption is that the GDNs own this part of the process from a control perspective).
- Once all the customers are confirmed off gas, the GDNs will use the recompression equipment to remove all the natural gas from the system and reinject the network with hydrogen.
- Simultaneously all the customer equipment is made hydrogen ready. Note this could be done outside the ownership boundary of the GDNs.
- Once all the customers are hydrogen ready, and the network filled with hydrogen, the GDNs will put the customers back on gas.
- There will be other costs and requirements around customer welfare etc which may lead to additional costs outside the scope of this work.

6.2 | Customer transition

Customer transition assumptions

Removing the natural gas from the system during transition

As described in previous sections of this report, stakeholder engagement identified the use of recompression equipment to ‘push’ the natural gas back up the pressure tiers is likely to be the most cost effective and environmentally friendly way to deal with residual natural gas.

As detailed on the previous page, transition timeframes need to be carefully managed to ensure minimum disruption.

Given the high-level nature of this project, detailed analysis was not undertaken to inform how many recompression units would be required, with the following assumptions made:

- Existing recompression equipment, as per the picture opposite, is designed for use at higher pressure tiers e.g. NTS, and is capable of recompression large volumes of gas.
- The use of multiple, equivalent units is considered necessary in order to remove the residual gas in the segment in the short timeframe allowed.
- The project team have assumed that 1 recompression unit would be required at the PRS level (in order to push the gas back into the methane LTS), with additional units located at each of the 16 district governors (removing the gas from the LP network into the MP/IP tier before the PRS).

Note for simplicity and consistency these assumptions are applied across the high, balanced and low scenarios and whether the segment transitions to hydrogen or is decommissioned. We have accounted for the need of sectorisation valves within the modelling.

Mobile recompression equipment

Source: PMC

6.2 | Customer transition

Customer transition assumptions

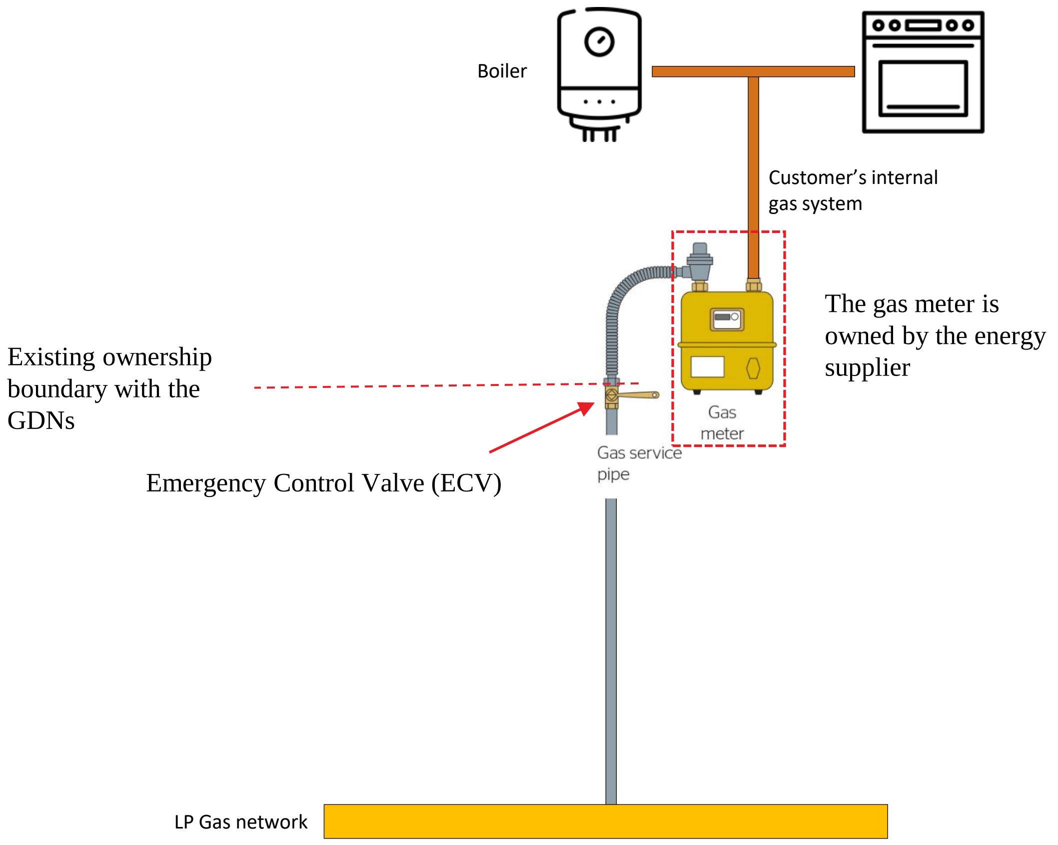
Disconnecting customers from the gas system

The customer disconnection process is described in detail in Section 4 of this report. This page identifies the transition approach taken, as well as identifying which parts of the process would fall under the remit of the GDNs.

Whilst the GDNs provide public quotations for carrying out this process today (as customers voluntarily transition off gas), the project team has imagined a highly-enabled, centrally led approach:

- It is assumed that entire network segments will be transitioned off gas in one go, allowing the gas disconnection process to transition from ad hoc work, to a more formal programme of work.
- It is assumed that the customer's energy supplier will have closed the ECV and temporarily capped it, as well as removed the meter. They would also purge the customer system of residual gas. The customer would then remove the internal gas system and appliances.
- The GDN would then permanently disconnect the customer by capping the service pipe outside of the customer premises, remove the ECV and remediate the customer premises.

By envisioning this as a formal programme of works, the project team anticipate the cost attributed to work carried out by the GDNs could be reduced.



Customer gas connection

Source: Arup

6.2 | Customer transition

Customer transition assumptions

Modelling assumptions

In order to model all three scenarios, Arup have adopted the following modelling approach, common to all scenarios:

Segments transition per year

- 92 segments deenergised per year across all scenarios to meet the customer transition forecasts

Methane removal works (required for either hydrogen conversion or decommissioning)

- 17 recompression rigs required per segment, with an associated capital cost over a 15-year lifetime of £250,000 per unit
- 27-full time equivalent (FTE) days of work per recompression rig including transport, set up, operations, tear down, maintenance and relocation
- Assume £60/hr for field force

Customer works – hydrogen conversion

- 30 mins per customer to take customers off methane
- 30 mins per customer to reconnect customers with hydrogen
- 1,351 FTEs of field force required per segment, assuming the above works and methane removal will be required to take place within 48hrs
- Assume £60/hr for field force

Customer works – gas disconnection

- As described on the previous page this would include disconnecting the customer from gas, making safe and then removing equipment from the customers' premises
- Each GDN provides public quotations for this work which have been averaged at £1,450 per customer in Arup's modelling

6.2 | Decommissioning

Gas network deenergising and decommissioning

Decommissioning assumptions

As per Section 4 of this report, there are a number of potential use cases for the gas system is deemed surplus to requirements, however this project does not seek to consider such options as per the project scope.

The following decommissioning treatment has been made per asset type, in order to understand the potential implications:

- NTS and LTS being of steel construction and large diameter would present a long term safety risk of asset degradation and potential subsidence. As per existing convention these assets would either be removed, or alternatively grouted to mitigate subsidence risk.
    - Grouting is an existing technique for decommissioning. The pipe will be prepped for decommissioning, with all valves etc removed. It is then split up into c. 400m lengths and filled with an aerated grout mix. The ends are then capped and reburied.

- PE pipes avoid hydrogen gas embrittlement and are typically smaller in diameter. This poses a minimal safety risk, and with appropriate subdivision and capping to prevent environmental risks, would be left in situ.

- Metallic pipes would be suspect to significant hydrogen gas embrittlement, but due to the smaller diameter presents less of a safety risk. As per current convention in the IMRRP, with appropriate subdivision and capping to prevent environmental risks, these pipes can be left in situ.

- Above ground equipment (compressors, pressure reduction stations etc.) would likely be removed. The cost of removal and disassembly is typically considered to be offset by the scrap value of the steel.

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6.3 | The GB Gas Network As Is – 2023 Part A

GB gas system overview – network boundaries

The diagram opposite presents a simplified illustration of the GB gas system.

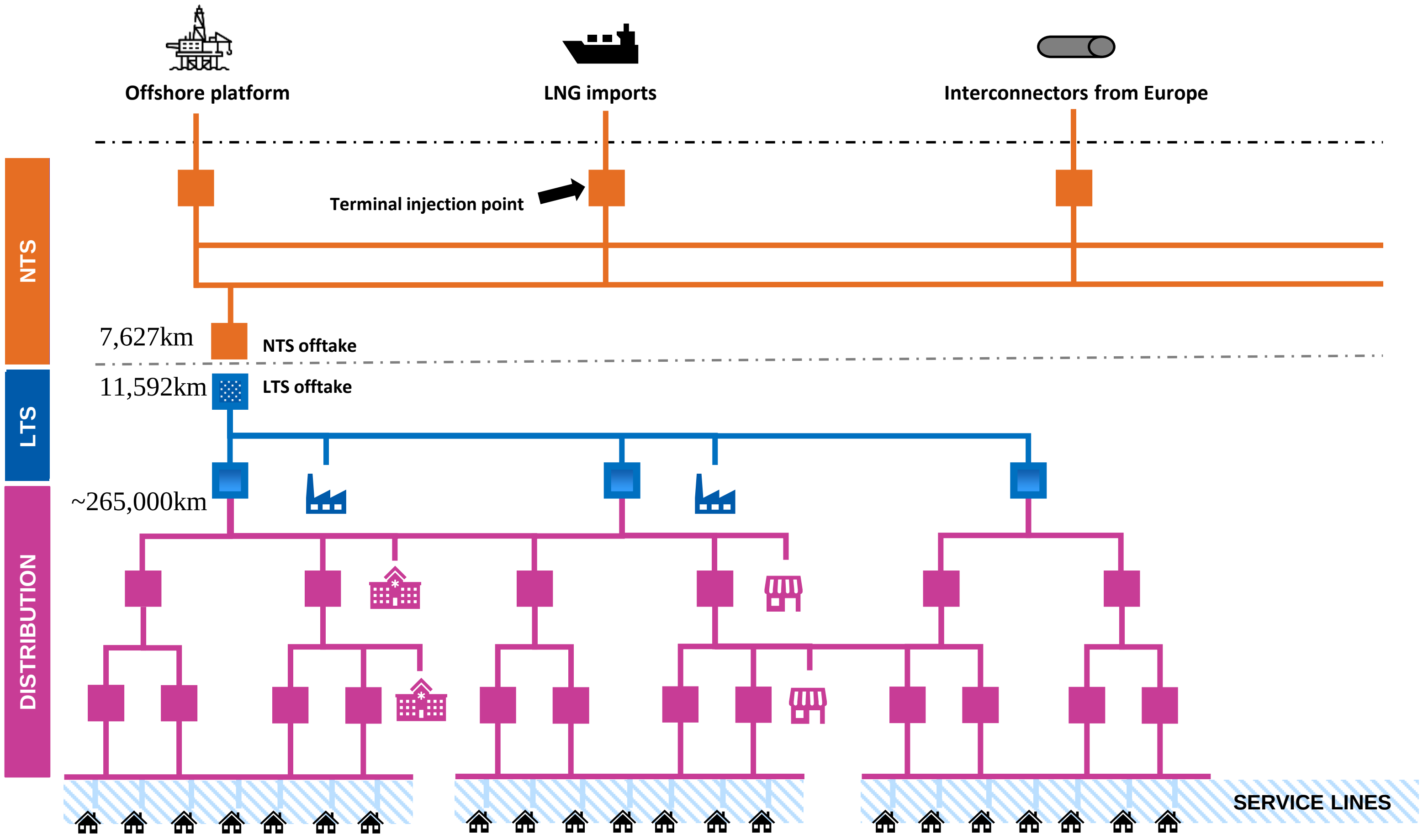
National Gas Transmission (NGT) operates the National Transmission System (NTS), a high pressure pipeline responsible for the transport of gas at a national level. This NTS is effectively also a storage asset given the large volumes of gas that are contained within the system.

Gas comes off the NTS at an offtake site. Such sites also represent the ownership boundary between NGT and the 4 gas Distribution Networks (GDNs):

- Cadent
- Northern Gas Networks (NGN)
- Scotia Gas Network (SGN)
- Wales and West Utilities (WWU)

Within the GDNs there are 2 main tiers within the system:

- The Local Transmission System (LTS); a high pressure network responsible for the transport of gas within a region.
- The Distribution network; a lower pressure system responsible for distributing gas around cities, towns and villages. This is the part of the network that connects the majority of customers.

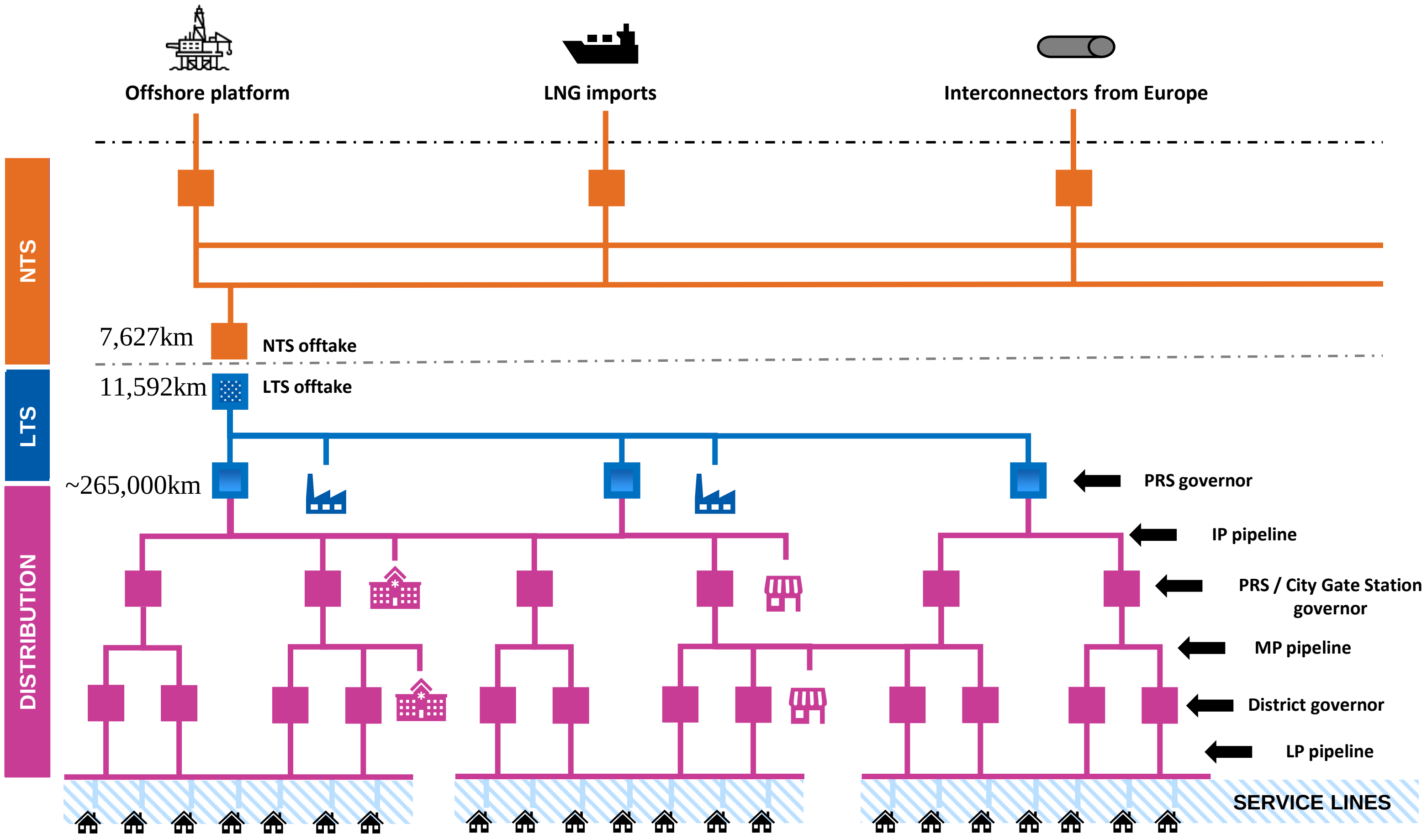


6.3 | The GB Gas Network As Is – 2023 Part B

GB gas system overview - pressure tiers and pipeline materials

Each tier of the network has a different operating pressure:

- The NTS is the highest pressure within the network, operating at c. 75 bar. Due to the high operating pressures and volumes transported, the NTS is made from large diameter steel pipes.
- Similarly the LTS also operates at high pressure using large diameter steel pipeline.
- The distribution network is comprised of up to 3 additional pressure tiers of between 0.075 and 7 bar - intermediate pressure (IP) medium pressure (MP), low pressure (LP), and- with pressure reduction equipment (governors) between each pressure tier.
  - The distribution network is typically comprised of polyethylene (PE) pipes such as high density Polyethylene (HDPE), however there are some legacy iron mains in the network. This iron is being phased out over time under a risk based framework, the Iron Mains Risk Reduction Programme (IMRRP).
  - The IP And MP networks also contain steel or (HDPE) to manage the higher pressure.
  - Service pipes are what connect customers to the network. Whilst the majority of these are PE, there are some legacy steel and iron services in operation today. These legacy assets are also being opportunistically phased out of the network when encountered as part of the IMRRP.



6.3 | Modelling approach

Overview

This section of the report details the exact modelling approach taken to cost the chosen scenarios. Using the methodology defined in the previous section, the transition scenarios can be modelled using the various technical and unit cost data.

Given the high-level nature of the project, and for consistency, Arup have used the technical network data found in the network’s regulatory reporting packs, as well as the corresponding Minimum Economic Asset Value (MEAV) cost as defined under Ofgem’s cost framework. The project team consider the use of these data is suited to the overall approach and methodology of this project, and provides transparency over the modelling carried out. Note in order to preserve the confidentiality of individual network data, the modelling is carried out at a system level, using weighted average MEAV costs from each of the distribution networks.

The model structure speaks to the scenario methodologies, detailed earlier in this report. Given all of the scenario methodologies are slightly different, Arup have adopted the following modelling hierarchy layout:

- Hydrogen NTS backbone; cost breakdown includes pipeline, compressors and injection point infrastructure costs to enable a hydrogen NTS backbone.
- Hydrogen LTS backbone; costs breakdown includes pipeline, NTS exit and LTS entry infrastructure costs to enable a hydrogen LTS backbone.
- Distribution network enabling works; costs include the replacement of non-PE pipes and services, as well as any replacement or modification works to pressure reduction infrastructure.
- Industrial customer transition; costs associated with transitioning industrial customers including any dedicated pressure reduction equipment.
- Domestic customer transition; costs associated with customer transition (either to hydrogen, or disconnected from the gas system), as well as the costs associated with the removal of methane from the distribution layer.
- Repurposing (NTS and LTS); costs associated with any of the NTS or LTS for hydrogen use as required by the scenario.
- Decommissioning; costs associated with decommissioning the gas system.

Section navigation

- Scenario modelling; each scenario will be discussed individually, with the specific assumptions made under each modelling block:
  - High scenario modelling
  - Balanced Scenario modelling
  - Low scenario modelling

6.4 | Scenario-specific transition methodology

High hydrogen scenario

6.4 | High Hydrogen scenario

Scenario description (2022 FES System Transformation)

2020s

- Industrial demand for hydrogen begins to emerge in the clusters. This sees the development of direct pipelines within the clusters from production to end use and commencement of work on a hydrogen backbone.
- There is small demand for hydrogen, but this is limited to a hydrogen town.

2030s

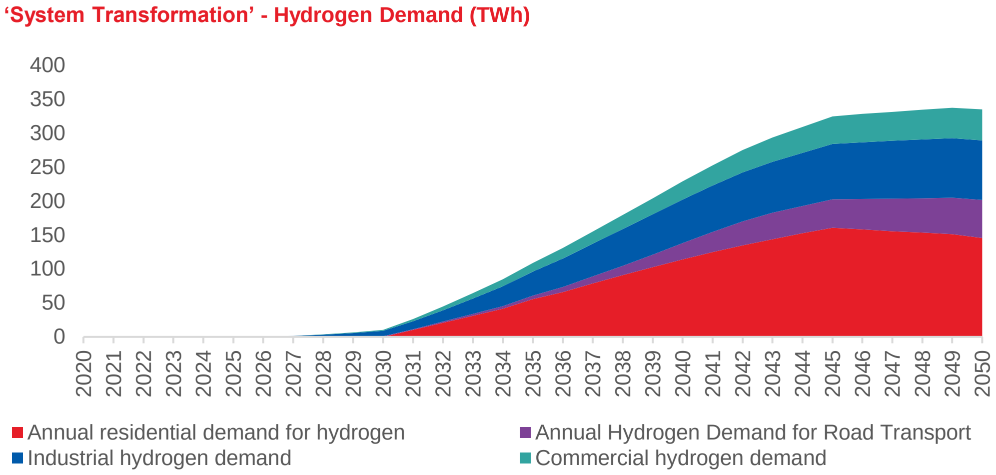
- Steady growth of industrial demand in the clusters at the start of the 2030s. Users that are located outside of the clusters convert when hydrogen for heating occurs in their area.
- First demand for hydrogen for heating in 2031, this demand is around the Northern clusters. This gradually increases and then ramps up from 2034/2035 at a consistent pace to the mid 2040s. Small industrial & commercial users convert to 100% hydrogen in line with domestic demand.

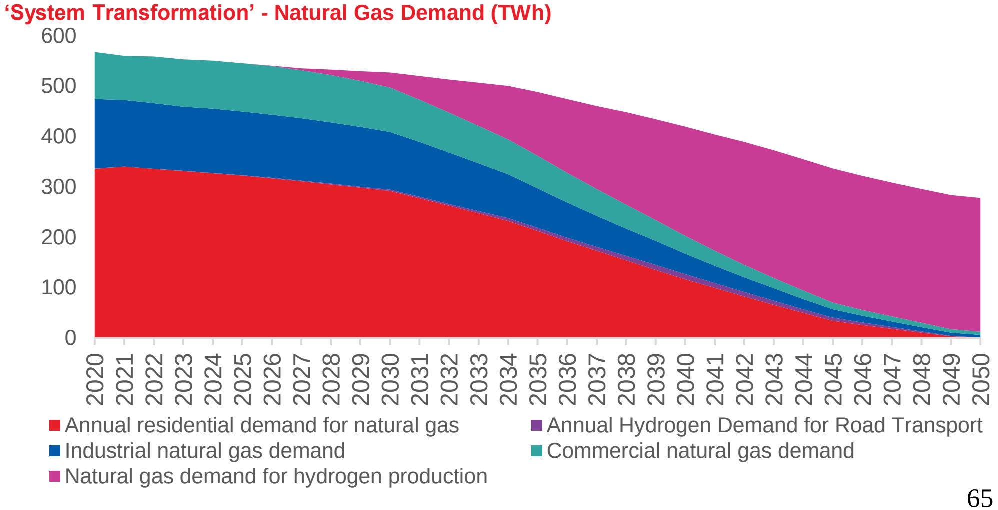
2040s

- Overall demand continues to grow in the first half of the decade, levelling off from 2045-2050.
- Residential demand continues to grow until circa 2045 when it begins to drop off slightly. The drop in residential demand is netted off with some small continued growth in demand from road transport and industrial hydrogen.

2050

- Hydrogen is used in the majority of homes, resulting in a widespread hydrogen network. Hydrogen is also used widely in industrial and commercial usages and for non-personal transport solutions.





Source: National Grid, Future Energy Scenarios [29]

6.4 | High Hydrogen scenario

Translating the scenario into an end state for the gas transmission network

Size of the transmission network in this scenario

- In the scenario industrial and commercial hydrogen demand develops in the 2020s and 2030s, with domestic demand and transport from 2035 onwards.
- By 2030s the hydrogen system will need to be capable of meeting 1 in 20 demand for industry, with the capability of transitioning to domestic demand by 2035.
- An independent hydrogen backbone is considered necessary, in order to meet the terms of the scenario. Given the geographical coverage requirements, a backbone equivalent to 20% of the existing NTS system is considered necessary.
- Once this hydrogen backbone is developed and industrial customers connected, it is anticipated that the NTS's network capability will increase to the point that discrete sections can be re-purposed, depending on technical suitability.
- As more customers transition to the hydrogen system, natural gas demand reduces on the NTS, improving the network capability. With improved network capability, more sections of the NTS can be repurposed for hydrogen and integrated into the hydrogen backbone.
- Note as per the natural gas demand chart on the previous page, by 2050 there is a significant demand for natural gas to make hydrogen via methane reformation (c. 265 TWh). Methane reformation at this scale is anticipated to be located on the sites of existing NTS entry points and will therefore not require any network assets.

Timing impact of transmission network development on the scenario demand and production

- Timings of large-scale industrial demands due to connect in the late 2020s/early 2030s are unchanged in the scenarios.

Size of the distribution network in this scenario

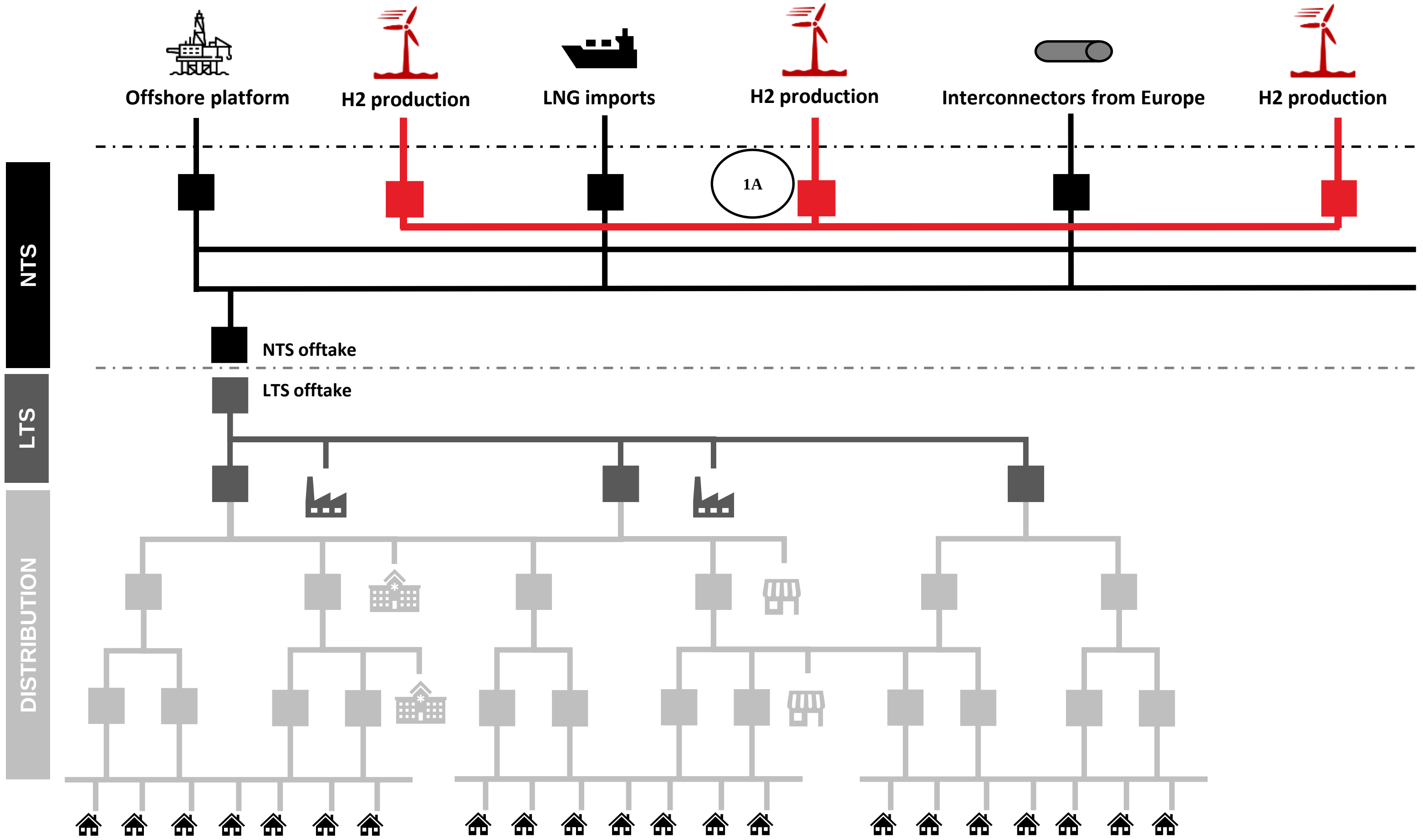
- In the scenario industrial and commercial hydrogen demand develops in the 2020s and 2030s, with domestic demand and transport from 2035 onwards.
- The scenario assumes that more than 50% of homes either have a hydrogen boiler or a hybrid heat pump with a hydrogen boiler. This results in a widespread GB hydrogen network by 2050.

Timing impact of distribution network development on the scenario demand and production

- The hydrogen backbone is developed by 2035, however, extensive works to the distribution network continue into the 2040s. This is because of:
  - The need to remove the remaining iron is removed from the gas network post the completion of the IMRRP before hydrogen is deployed,
  - The need for the hydrogen backbone to connect sufficient levels of hydrogen production to meet demand,
  - Based on the Towns Gas conversion, the domestic gas conversion will be restricted to summer months, and this combined with the level of sufficiently developed supply chains and trained resources to undertake the annual conversions process, will limit the number of homes that can be converted on an annual basis.
- Based on this, the uptake of domestic and transport demands is not assumed to start at mass scale until after the hydrogen backbone is developed in 2035 and results in the demands for these scenarios materializing later such that conversion commences in 2035 until 2050. Some demands near to the clusters that have been converted can be connected earlier than 2035 where there is excess hydrogen created that is not consumed by industrial demands and the IMRRP have been sufficiently deployed.

6.4 | High Hydrogen scenario

Step 1. Hydrogen NTS Backbone



1a New hydrogen gas NTS build

1a New hydrogen ready compressors built for the hydrogen backbone

1a New injection points to support the new hydrogen backbone.

6.4 | High Hydrogen scenario

Hydrogen NTS backbone capex

Assumptions

As per the methodology, a hydrogen backbone equivalent to 20% of the existing NTS is required. Modelling assumptions include:

- 1,525 km of new pipeline, assumed to be laid in parallel to the existing NTS, equivalent to 20% of the existing NTS.
- 14 compressor units, assumed to be constructed at existing compressor stations, equivalent to 20% of the existing compressor fleet.
- 7 NTS injection points, one assumed for each of the clusters and an additional one at Bacton for European interconnectivity.

Timing

- As per the scenario, industrial demand in the clusters rapidly develops in the early 2030s, with a backbone required by 2035.
- Given the scale of this infrastructure deployment, the project team assumed a period of 10 years is required, resulting in spend starting in 2025.

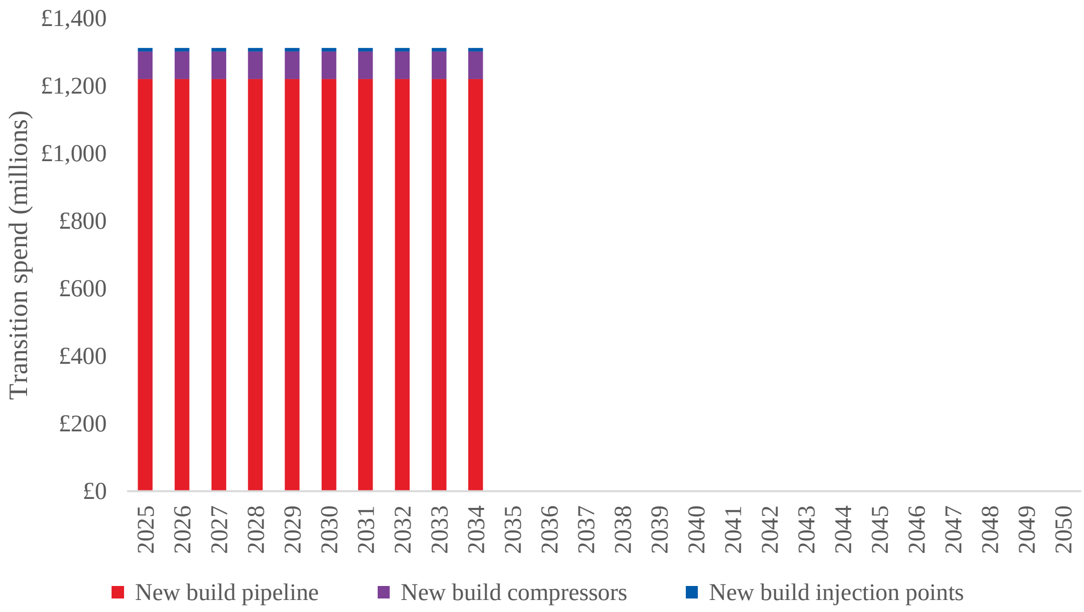
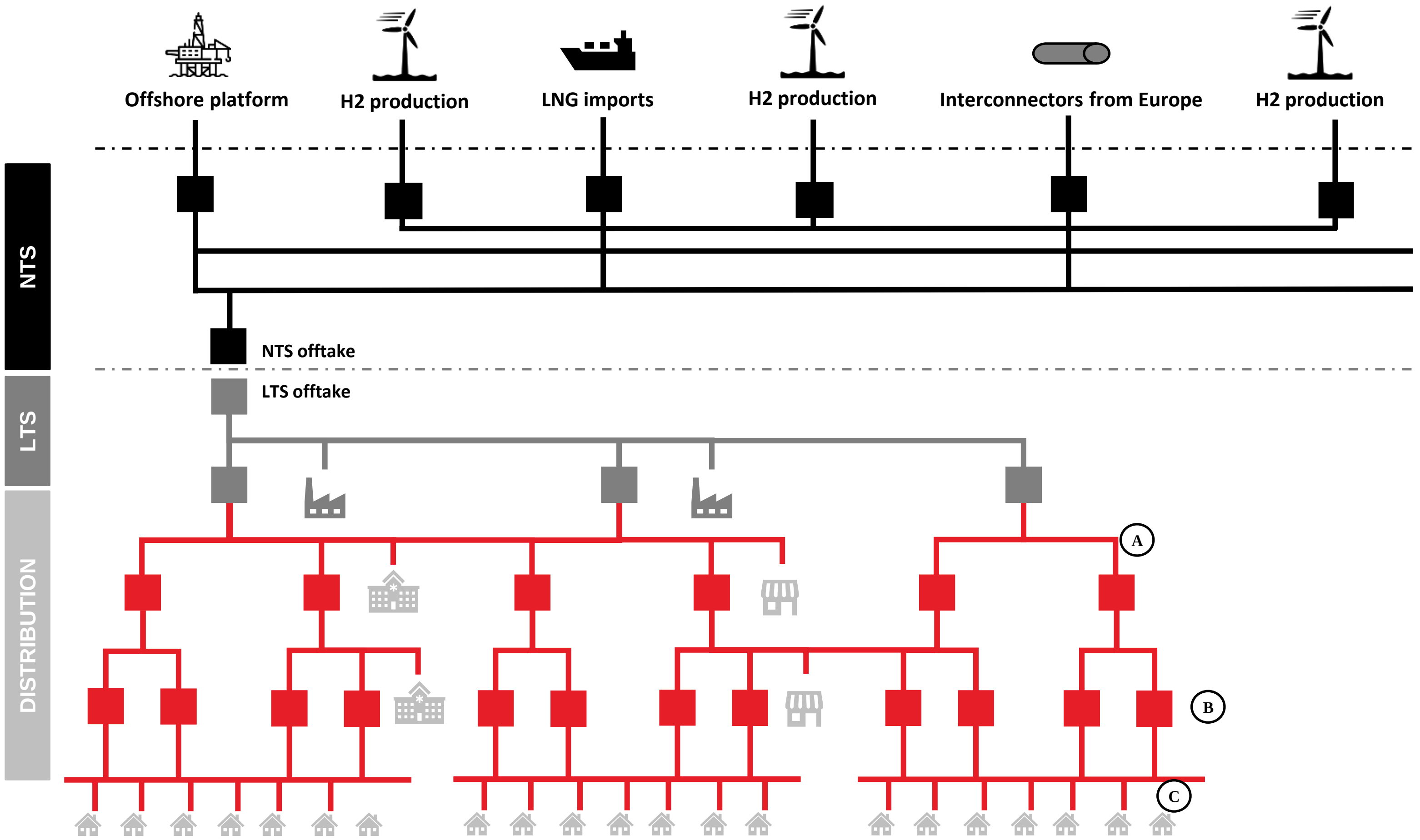


Figure 1. NTS hydrogen backbone

Source: Arup analysis

6.4 | High Hydrogen scenario

Step 2. GDN enabling works



2a

Non-PE mains replacement (as per HSE guidance at the time of this studies modelling phase.)

2b

Governor modification/replacement to make hydrogen ready

2c

Non- PE Service Lines pipeline replacement (as per HSE guidance)

ARUP

6.4 | High Hydrogen scenario

Distribution network enabling works capex

Assumptions

As per the methodology, domestic demand for hydrogen is expected to start in 2036, requiring all the distribution networks to be made fully ready by 2040. Modelling assumptions include:

- 100% of the remaining, non-PE mains are replaced, equivalent to 9,392km.
- 100% of the remaining non-PE services are replaced, equivalent to 655,654 services.
- Pressure reduction equipment is deemed to be hydrogen ready (with light modification) beyond 2020. By 2032, 40% of all pressure reduction equipment in circulation will need modification, with 60% requiring replacement:
    - PRSs; 828 units replaced, 552 units modified
    - District governors; 12,905 units replaced, 8,603 units modified
    - Service governors; 48,842 units replaced, 32,562 units modified

Timing

- As per the scenario, domestic transition happens from late 2030s onwards.
- This work is assumed to happen post 2032 (when the existing mains replacement programme has finished).
- The GDNs are assumed to take a targeted approach to these works, enabling some segments to be ready for hydrogen from 2036 onwards.

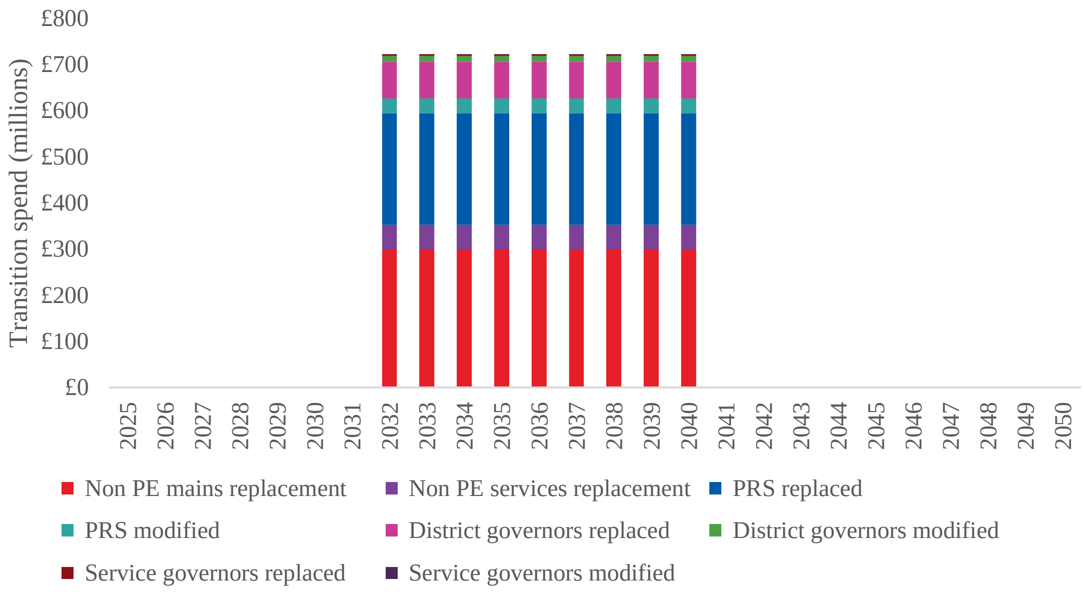


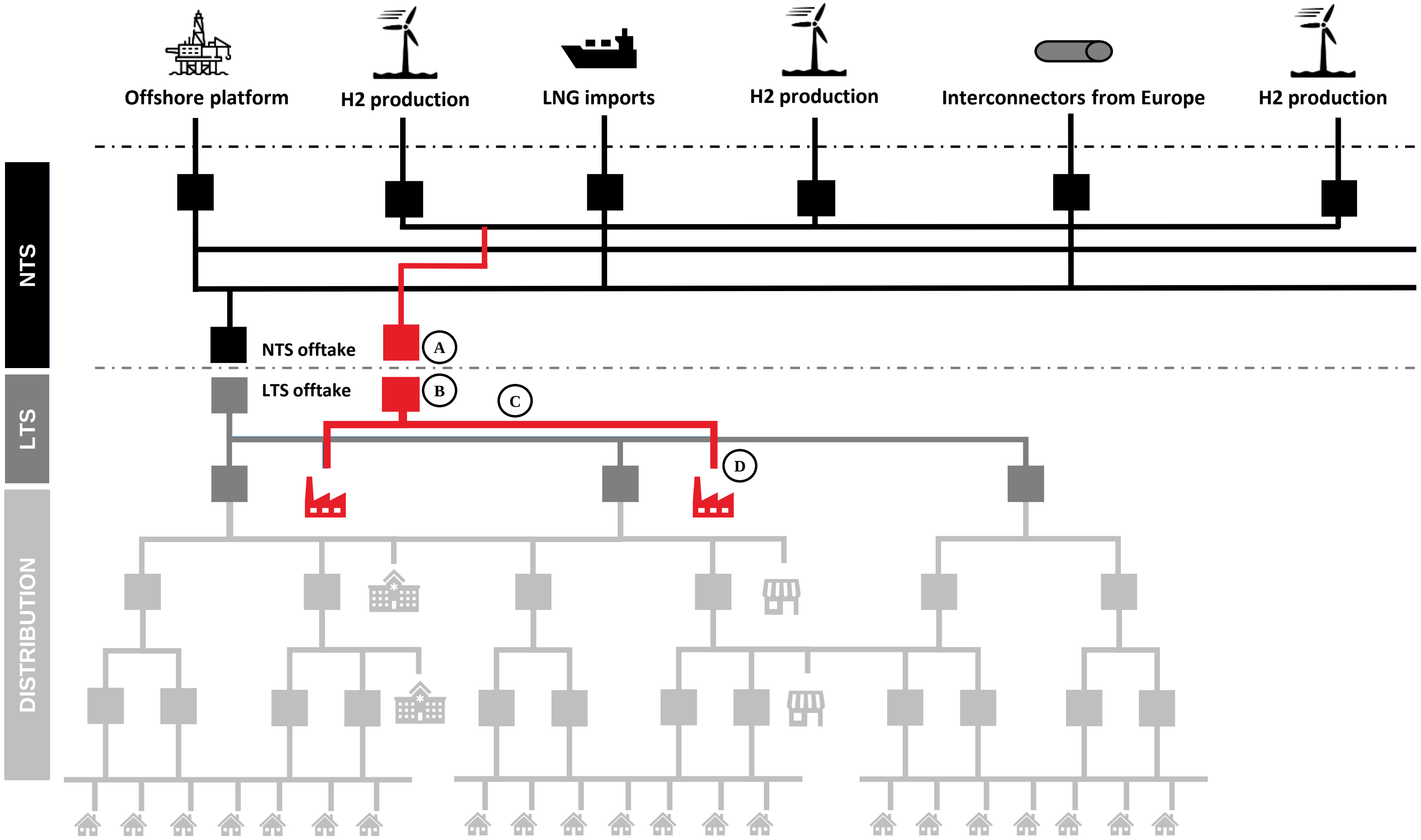
Figure 2. Distribution network enabling works

Source: Arup analysis

ARUP

6.4 | High Hydrogen scenario

Step 3. H2 backbone into the distribution layer to convert major industry



- **3a** New NTS offtake
- **3b** New gas entry points (LTS Offtakes)
- **3c** LTS new build to extend the hydrogen backbone into the distribution layer to connect major industrial customers
- **3d** Industrial customer transition (including modification / replacement of associated governor)

ARUP

6.4 | High Hydrogen scenario

Hydrogen LTS backbone capex

Assumptions

As per the methodology, a hydrogen backbone equivalent to 40% of the existing LTS is required in order to transition industrial customers and enable the domestic transition at scale. Modelling assumptions include:

- 4,637 km of pipeline, assumed to be laid in parallel to the existing LTS.
- 47 new NTS offtakes, assumed to be constructed adjacent to existing offtakes, equivalent to 40% of the existing fleet.
- 52 new LTS gas entry points, assumed to be constructed adjacent to existing entry points, equivalent to 40% of the existing fleet.

Timing

- As per the scenario, industrial demand outside of the clusters is expected to develop in the mid 2030s, with a backbone required by mid 2030s to transition industrial customers and enable domestic conversion.
- Given the scale of this infrastructure deployment, the project team assumed a period of 10 years is required, resulting in spend starting in 2027.

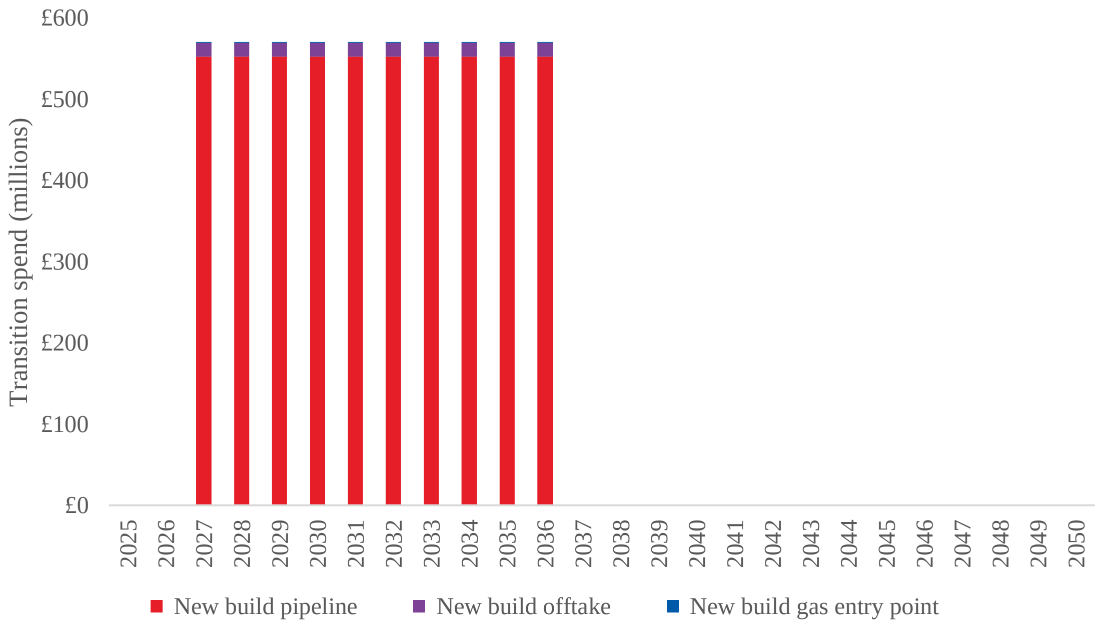


Figure 3. LTS hydrogen backbone

Source: Arup analysis

6.4 | High Hydrogen scenario

Industrial customer transition capex

Assumptions

As per the methodology, industrial demand for hydrogen starts in the 2030s. Modelling assumptions include:

- 100% of the industrial customers transition to hydrogen.
- As per section 6 of this report, pressure reduction equipment is deemed to be hydrogen ready (with light modification) beyond 2020. By 2032, 40% of all pressure reduction equipment in circulation will need modification, with 60% requiring replacement:
  - Non domestic governors; 5,911 units replaced, 3,941 units modified .

Timing

- As per the scenario, industrial transition happens from early 2030s onwards.

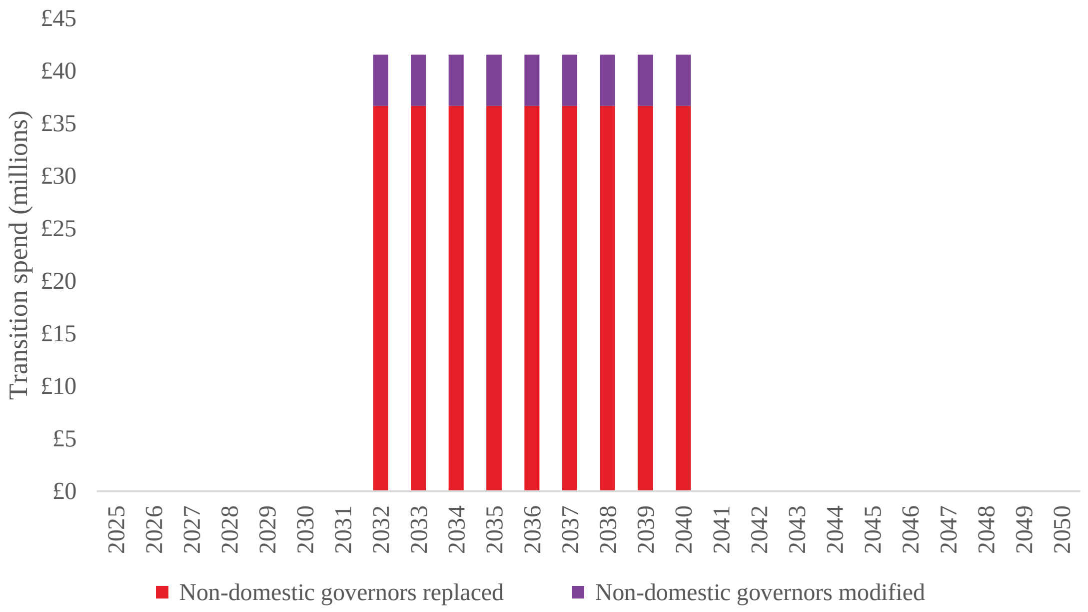


Figure 4. Industrial customer transition

Source: Arup analysis

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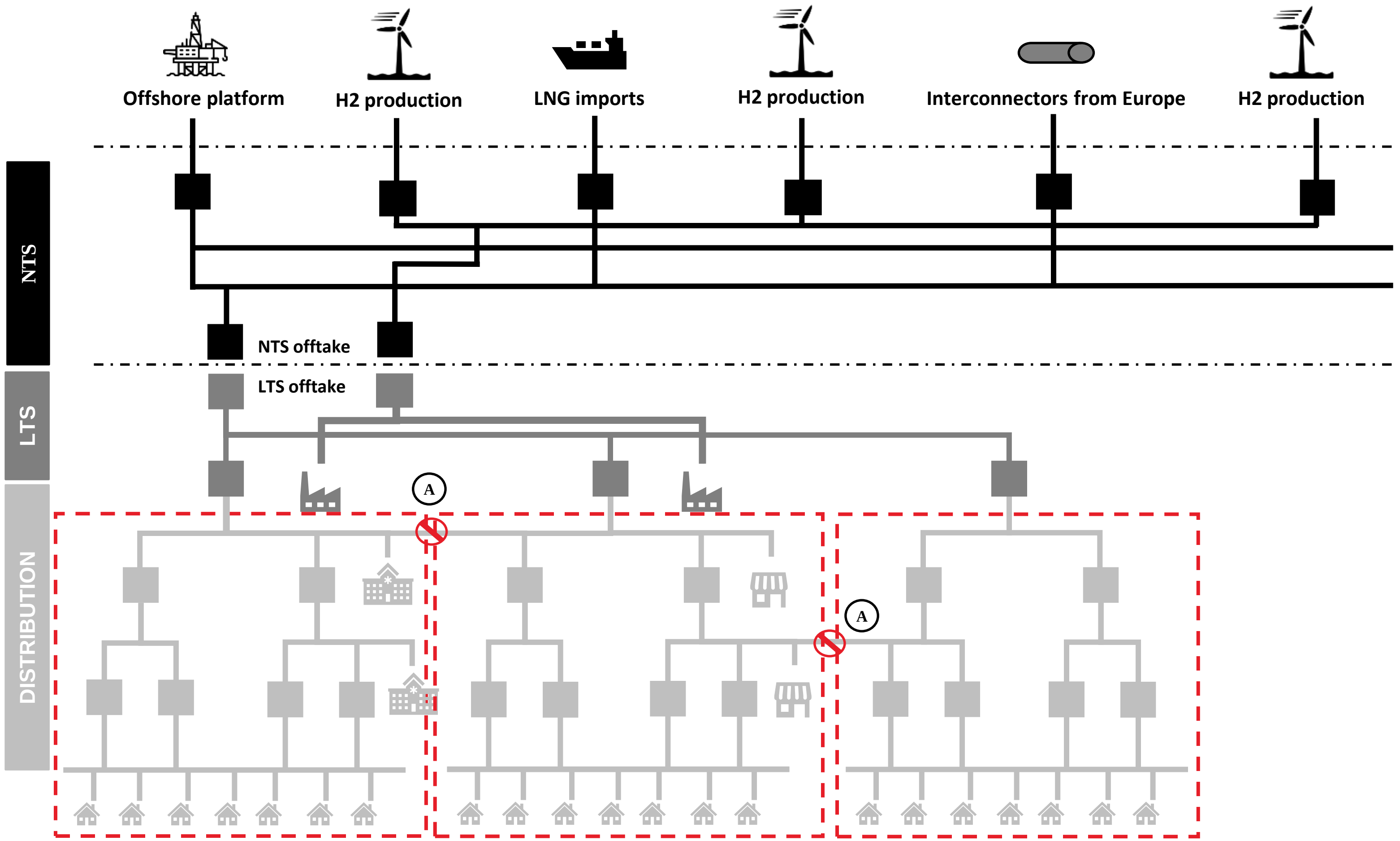
6.4 | High Hydrogen scenario

Step 4. Network segmentation

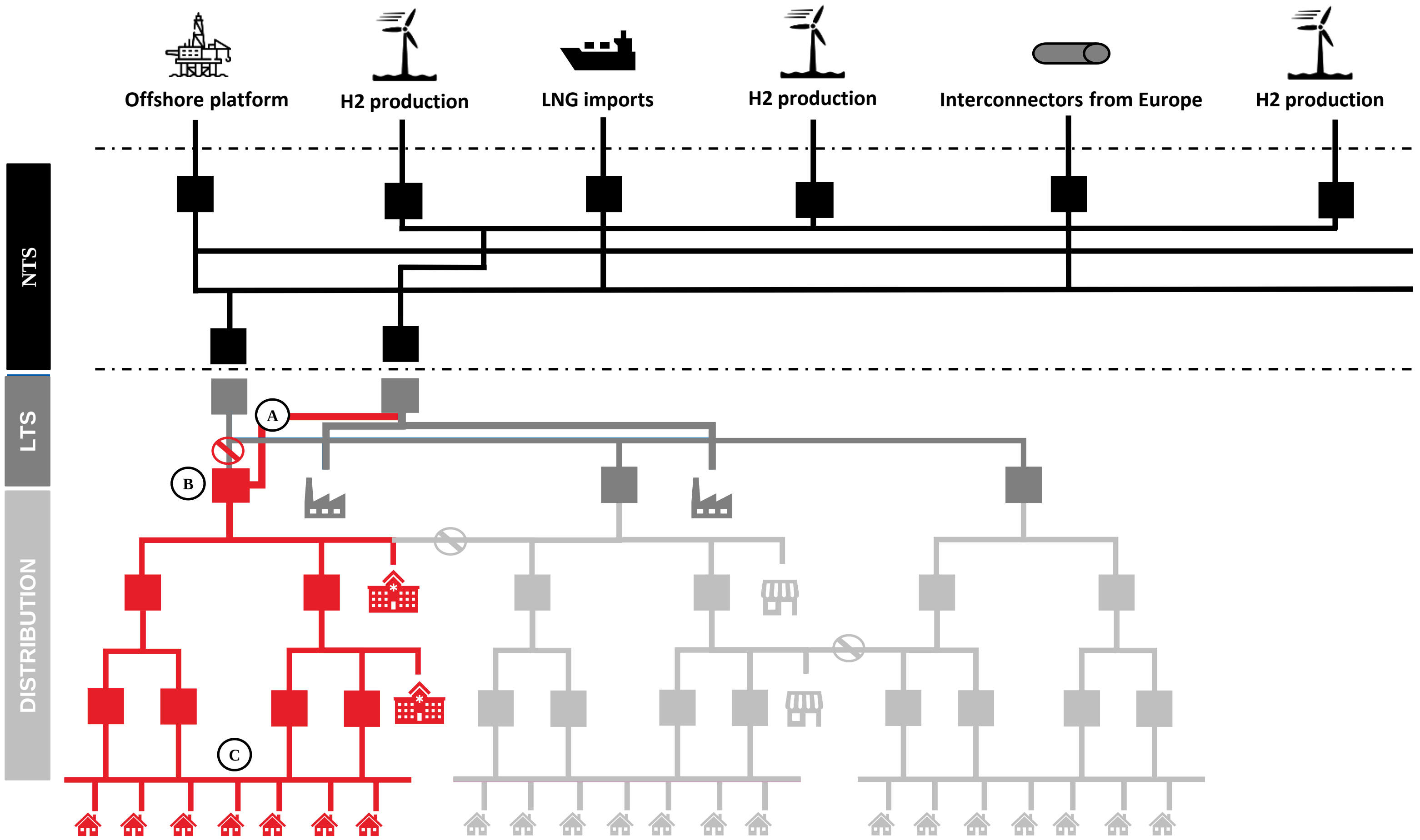


4a

Temporary de-meshing of the distribution network using sectorisation valves

6.4 | High Hydrogen scenario

Step 5. H2 for domestic heat in segments



5a New LTS spur into the PRS to allow the unmeshing and remeshing of the old methane and new hydrogen gas network respectively.

5b Modification / replacement of PRS to make hydrogen ready

5c Network segment transitioned to hydrogen; this will involve created a hydrogen ready section to be converted to hydrogen gas whilst maintaining adjacent the methane gas network.

ARUP

6.4 | High Hydrogen scenario

Domestic customer transition capex

Assumptions

As per the scenario, the majority of customer transition to hydrogen. Modelling assumptions include:

- 100% of the distribution network has the methane removed and replaced with hydrogen
- c. 5m customers choose to disconnect from the gas system
- c. 19m customers transition to hydrogen

Network transition costs include the labour and equipment required to remove the residual methane in the network.

Timing

- As per the scenario, customer transition occurs from 2036 onwards

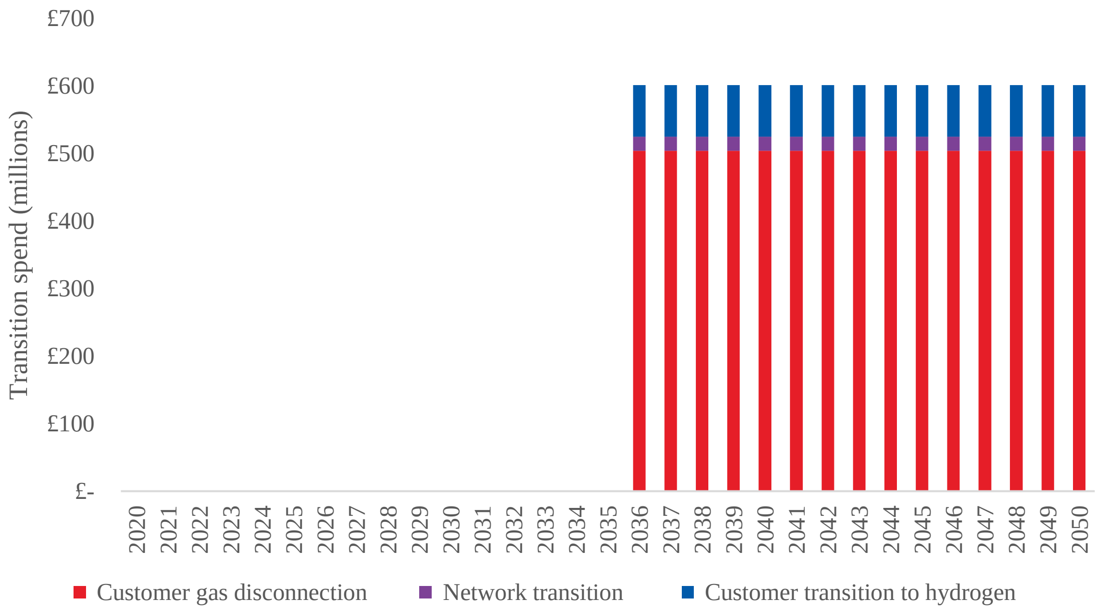
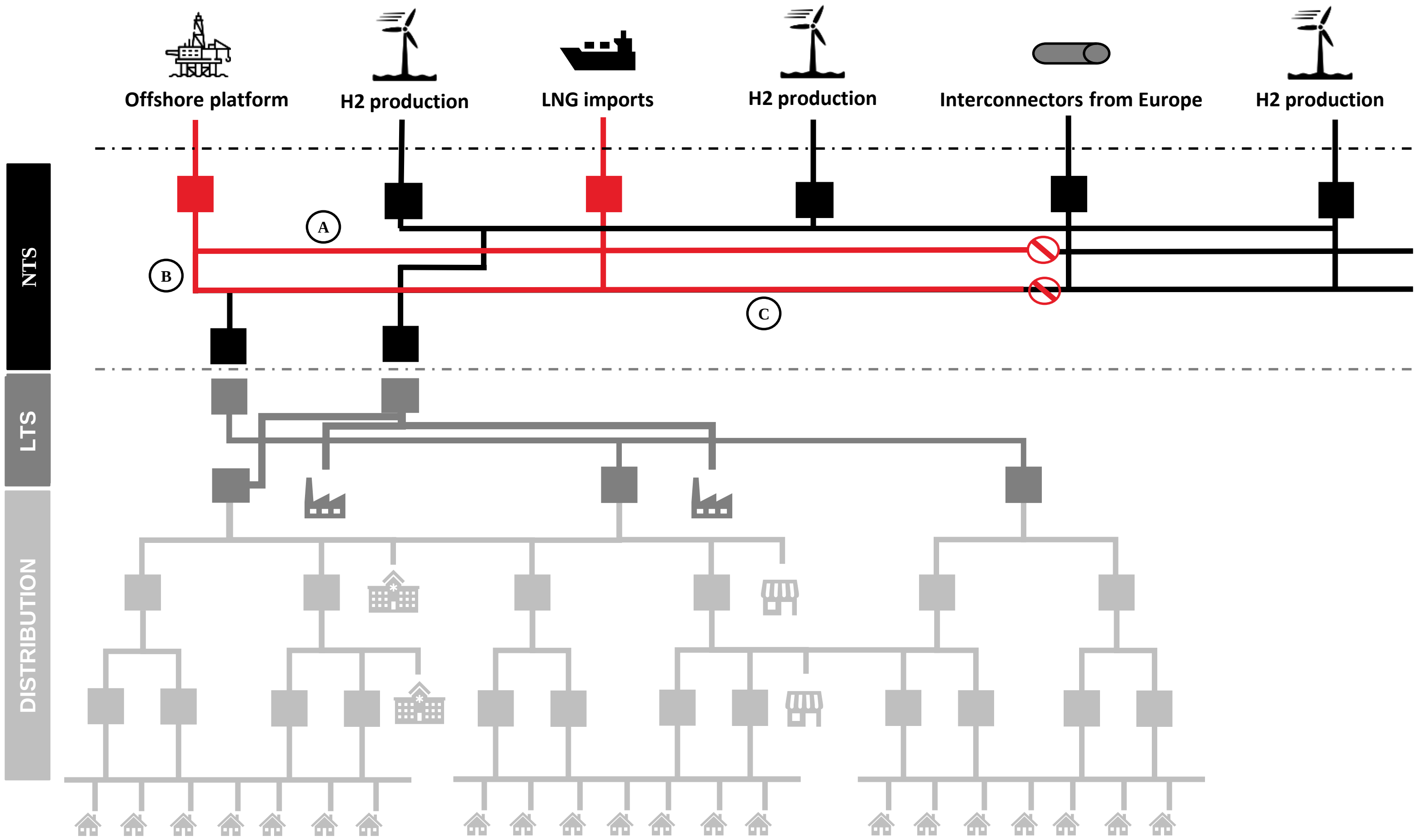


Figure 5. Domestic customer transition

Source: Arup analysis

6.4 | High Hydrogen scenario

Step 6i. Widespread H2 rollout in line with increased production – NTS level



6a Driven by increasing network capability, NTS repurposed and integrated into the hydrogen backbone

6b Existing compressors replaced with hydrogen compliant units

6c Additional compressors required (due to different characteristics of hydrogen vs natural gas)

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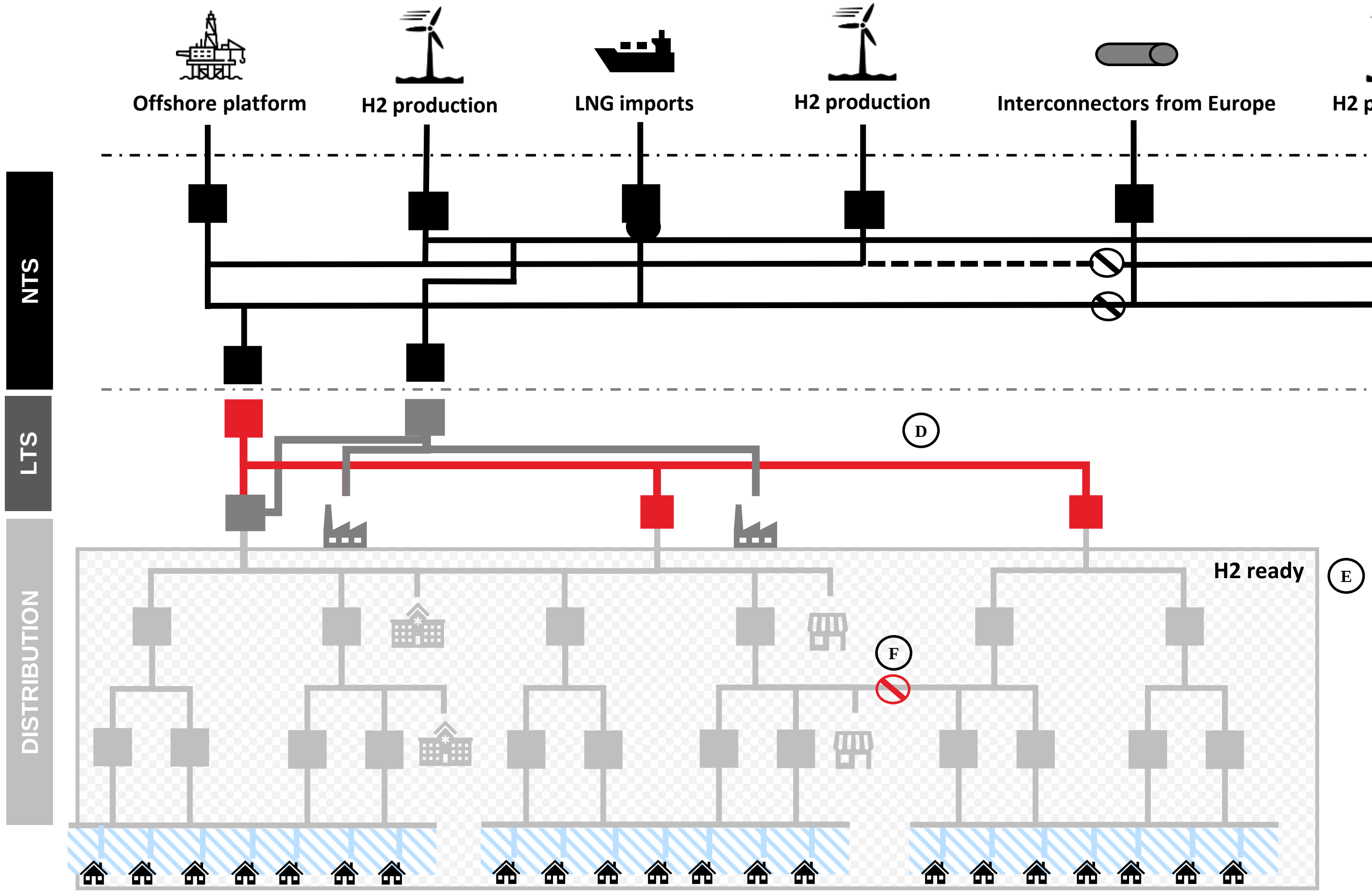
6.4 | High Hydrogen scenario

Step 6ii. Widespread H2 rollout in line with increased production – Distribution network



6d Repurposing of the LTS

6e All network segments transitioned to hydrogen

6f Re-meshing of the distribution network

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6.4 | High Hydrogen scenario

Repurposing (NTS and LTS) capex

Assumptions

As per the methodology, the NTS and LTS are repurposed as soon as is practicably possible. Assumptions include:

- 11% NTS converted due to metallurgy, equivalent to 839km
- 9% NTS replaced due to condition, equivalent to 686km
- 9% LTS replaced due to condition, equivalent to 1,043km
- 50% additional compressor stations required, equivalent to 12 new sites. 19 new compressors required at these stations, using the existing average of 1.5 units per station.

No NTS or LTS is assumed to be required for natural gas.

Timing

- Repurposing is assumed to be carried out as the domestic and industrial conversion frees up capacity on the natural gas system, from 2040 onwards.

Decommissioning

Assumptions

As per the methodology, no decommissioning of the NTS and LTS is forecast.

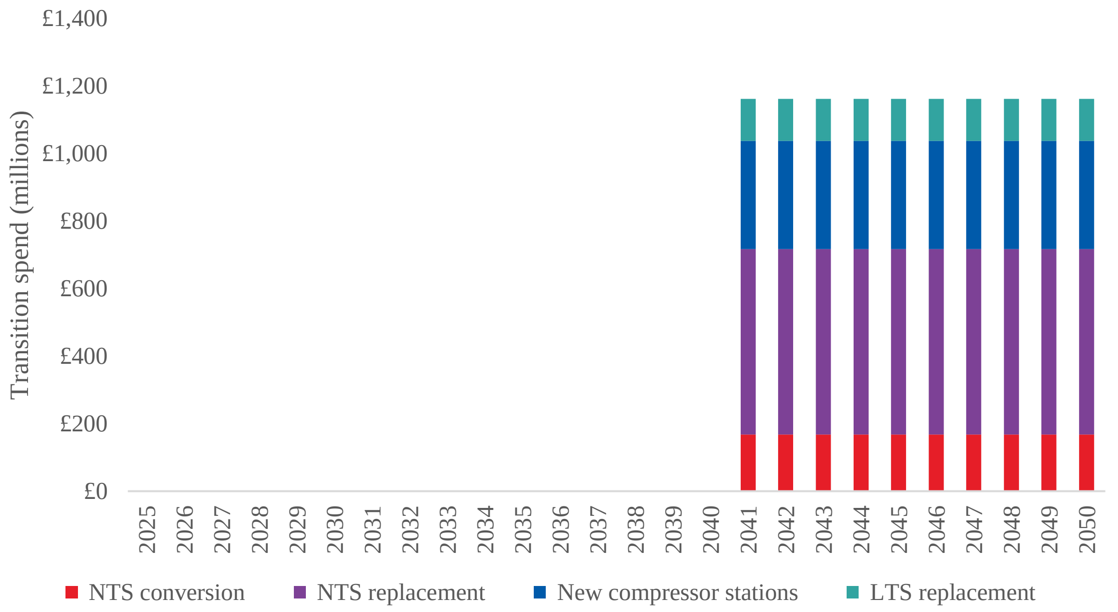


Figure 6. Repurposing (NTS and LTS)

Source: Arup analysis

ARUP

6.4 | High Hydrogen scenario

Overall Cost Summary

Figure 8. Summary of annual spend by category

Figure 7. Summary of total capex spend by category (£m)

Hydrogen NTS backbone	£	13,119	28%
Hydrogen LTS backbone	£	5,704	12%
Distribution enabling works	£	6,501	14%
Industrial customer transition	£	374	1%
Domestic customer transition	£	9,017	19%
Repurposing (NTS and LTS)	£	11,612	25%
Decommissioning	£	-	-
TOTAL	**£**	**46,328**	**100%**

Source: Arup analysis

ARUP

6.4 | High Hydrogen scenario

Summary of customer transition

The charts opposite present the domestic and minor Industrial and Commercial (I&C) customer transition (opposite, top) and the Major I&C customer transition (opposite, bottom) in the High scenario:

- Major I&C customers are defined by the need for a non domestic governor less than 200scm/h, as identified in the Regulatory Reporting Packs. Such customers would likely include major industrial users of energy that are likely hard to abate e.g. glass manufacturing and would likely be connected higher up the pressure tiers of the distribution network.
- Domestic and Minor I&C customers include all other customers such as homes, small industrial and commercial units, shops, warehouses etc. and would likely be connected lower down the pressure tiers of the distribution network.
- Domestic and Minor I&C transition; of the existing c. 24m natural gas customers today, c. 19m transition to hydrogen with c. 5.2m transitioning off the gas network on to alternative energy solutions.
- Major I&C transition; of the existing c. 9,800 natural gas customers today, 100% transition to hydrogen.

Figure 8. Domestic and Minor I&C customer transition

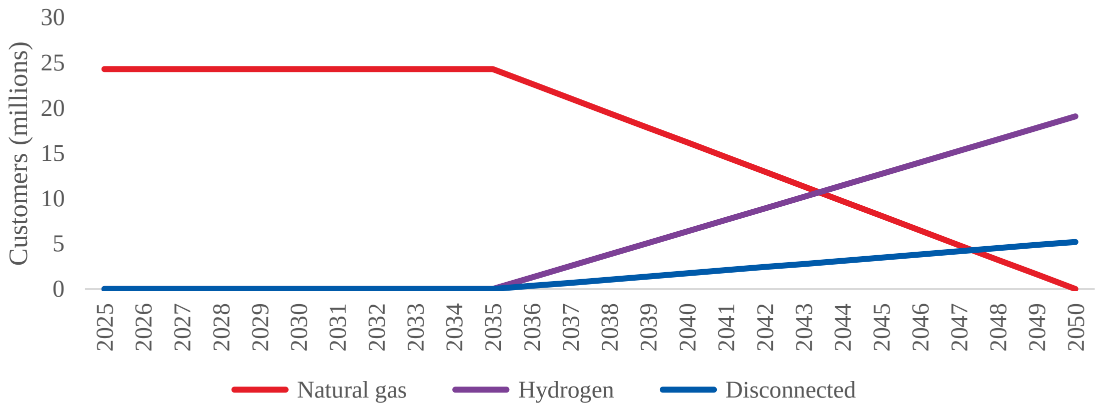
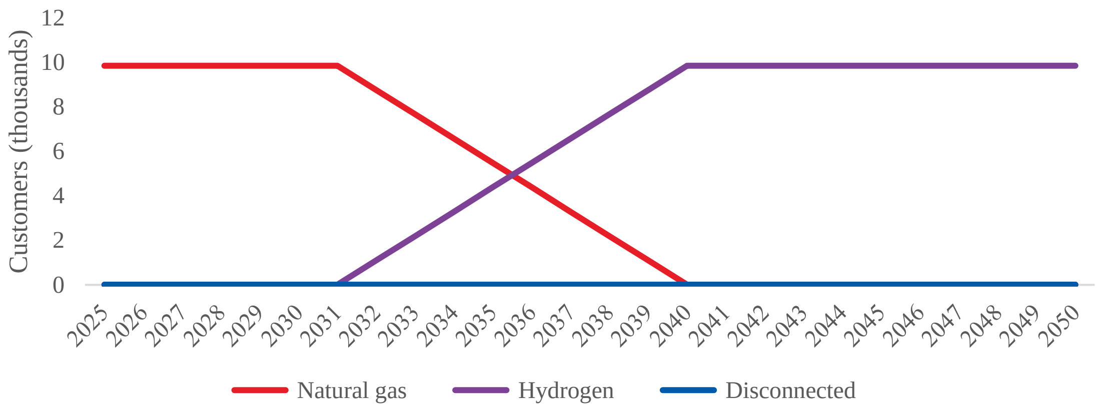


Figure 9. Major I&C customer transition



Source: Arup analysis

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6.5 | Scenario-specific transition methodology

Balanced hydrogen scenario

ARUP

6.5 | Balanced Hydrogen scenario

Scenario description (FES Leading the Way)

2020s

- Latter half of the 2020's sees some industrial demand grow around clusters driven by hard to decarbonise processes.
- At this stage, demand for hydrogen for heating is limited, because of alternative such as heat pumps.

2030s

- Growth in hydrogen demand driven by industrial and residential demand. Industrial demand remains focused around the clusters with Northern clusters first to establish. Residential demand emerging within the vicinity of the industrial clusters.

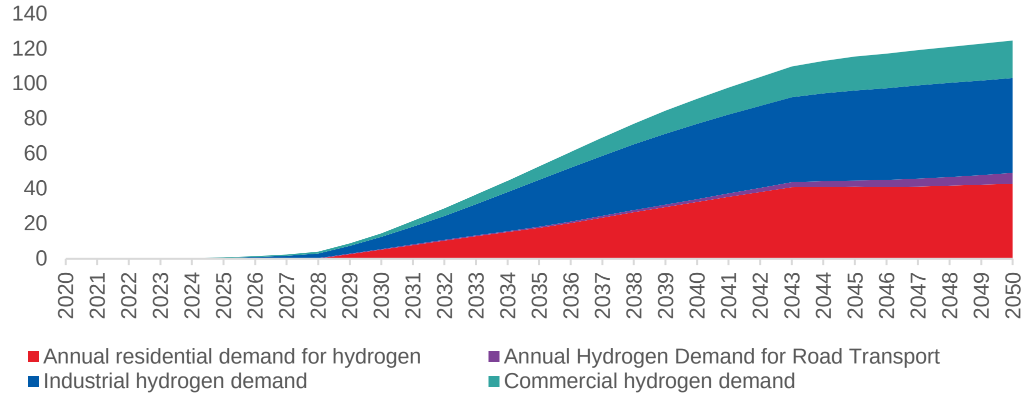
2040s

- Residential hydrogen boiler installations flatten from 2043 onwards as areas around clusters reach close to full conversion.
- Continued growth in industrial demand as some large offtakers move to industrial clusters.

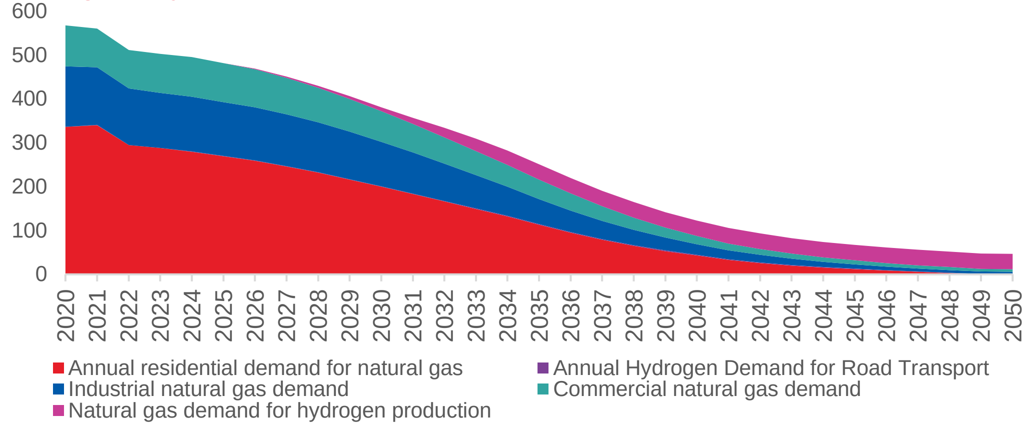
2050

- By 2050, the majority of hydrogen demand will be driven by industrial clusters, and residential properties within the vicinity of those clusters.

'Leading the Way' - Hydrogen Demand (TWh)



'Leading the Way' - Natural Gas Demand (TWh)



Source: National Grid, Future Energy Scenarios [29]

6.5 | Balanced Hydrogen scenario

Translating the FES scenario into an end state for the gas network

Size of the network in this scenario

As depicted in Section 5.2, the FES envisage the balanced scenario with a gas system largely unchanged from today, but with much lower customer penetration. The project team consider with a planned process it seems sensible to aim for higher penetration and it give more difference between scenarios if there are less segments at higher penetration and have made the following amendments to the assumptions:

- Domestic hydrogen 'bleeds out' from the backbone into the surrounding regions in a limited fashion. In line with wider customer trends to electrification, the project team have assumed that penetration rates in the hydrogen regions fall to 50% of current.
- This has not been modelled geographically.

Note as per the natural gas demand chart on the previous page, by 2050 there is demand for natural gas to make hydrogen via methane reformation (c. 35 TWh). In order to maximise flexibility of hydrogen production, 20% of the NTS is retained for natural gas.

Timing impact of network development on the scenario demand and production

- Similar to the High scenario, the hydrogen backbone is expected to be developed by 2035, however, works to the extensive works to the distribution network continue into the 2040s.
- Based on the rationale discussed under the High scenario, the uptake of domestic and transport demand is not assumed to start at mass scale until after the hydrogen backbone is developed in 2035. Consequently, conversion commences in 2035 until 2050.

Residual natural gas network

It is anticipated that there will be some, albeit small, residual demand for natural gas by 2050. This is assumed to be in the clusters for blue hydrogen generation, with associated Carbon Capture, Utilisation and Storage (CCUS). Accordingly, the project team has retained 20% of the NTS to accommodate this demand.

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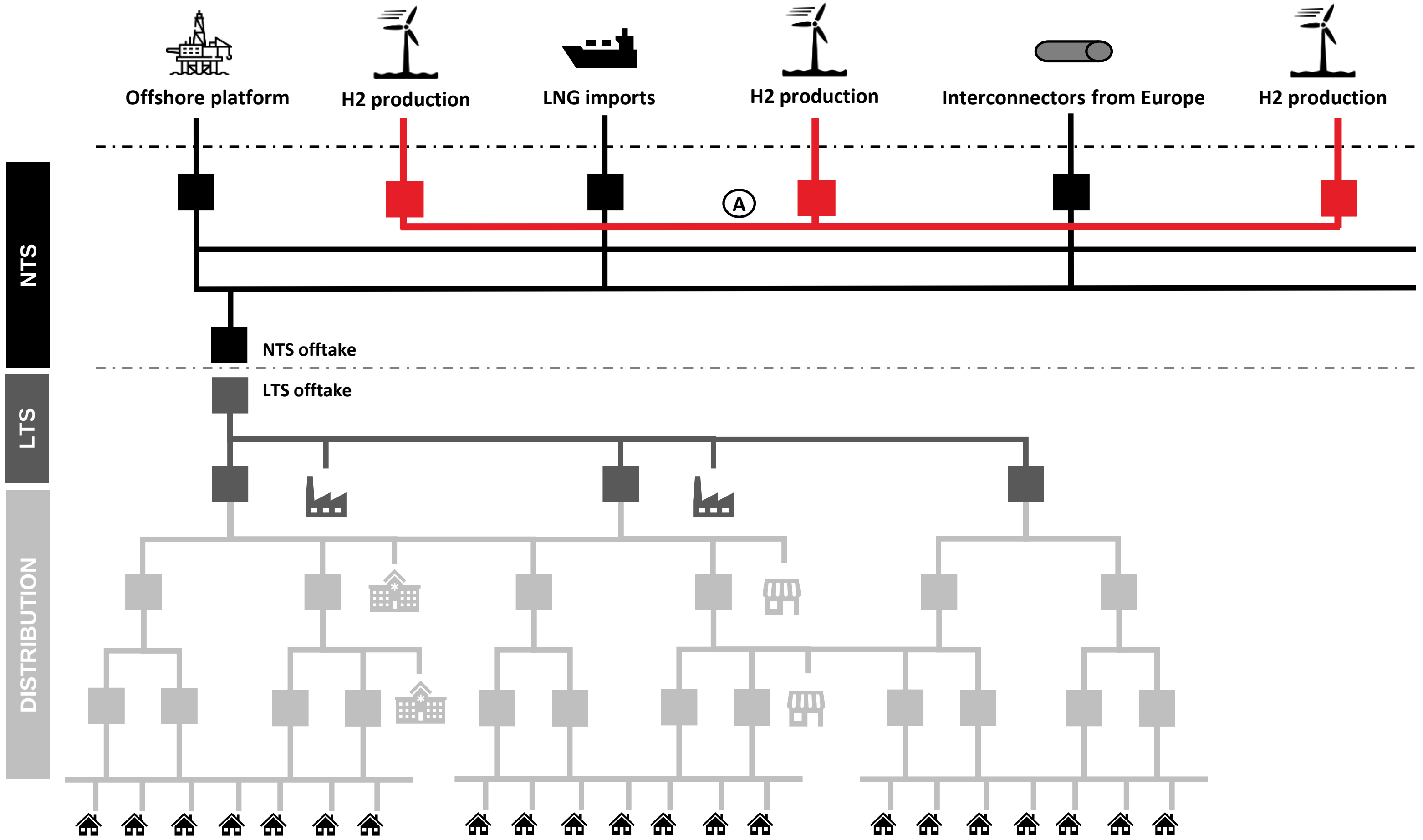
6.5 | Balanced Hydrogen scenario

Step 1. Hydrogen NTS Backbone



1a New build hydrogen NTS build

1a New hydrogen ready compressors built for the hydrogen backbone

1a New injection points to support the new hydrogen backbone

6.5 | Balanced Hydrogen scenario

Hydrogen NTS backbone capex

Assumptions

As per the methodology, a hydrogen backbone equivalent to 20% of the existing NTS is required. Modelling assumptions include:

- 1,525 km of pipeline, assumed to be laid in parallel to the existing NTS, equivalent to 20% of the existing NTS.
- 14 compressor units, assumed to be constructed at existing compressor stations, equivalent to 20% of the existing compressor fleet.
- 7 NTS injection points, one assumed for each of the clusters and an additional one at Bacton for European interconnectivity.

Timing

- As per the scenario, industrial demand in the clusters rapidly develops in the early 2030s, with a backbone required by 2035.
- Given the scale of this infrastructure deployment, the project team assumed a period of 10 years is required, resulting in spend starting in 2025.

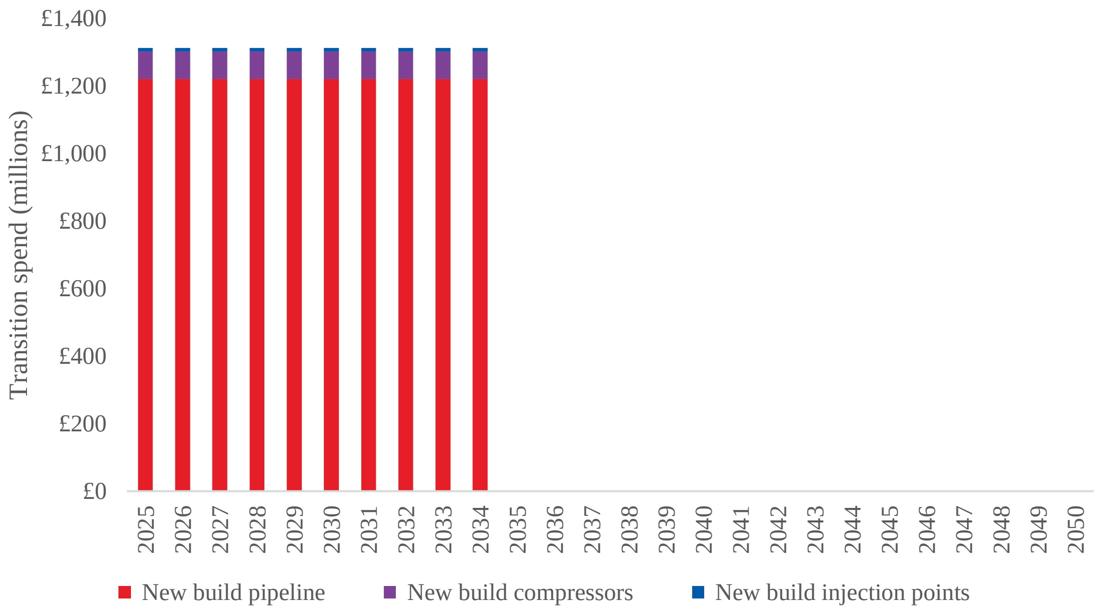


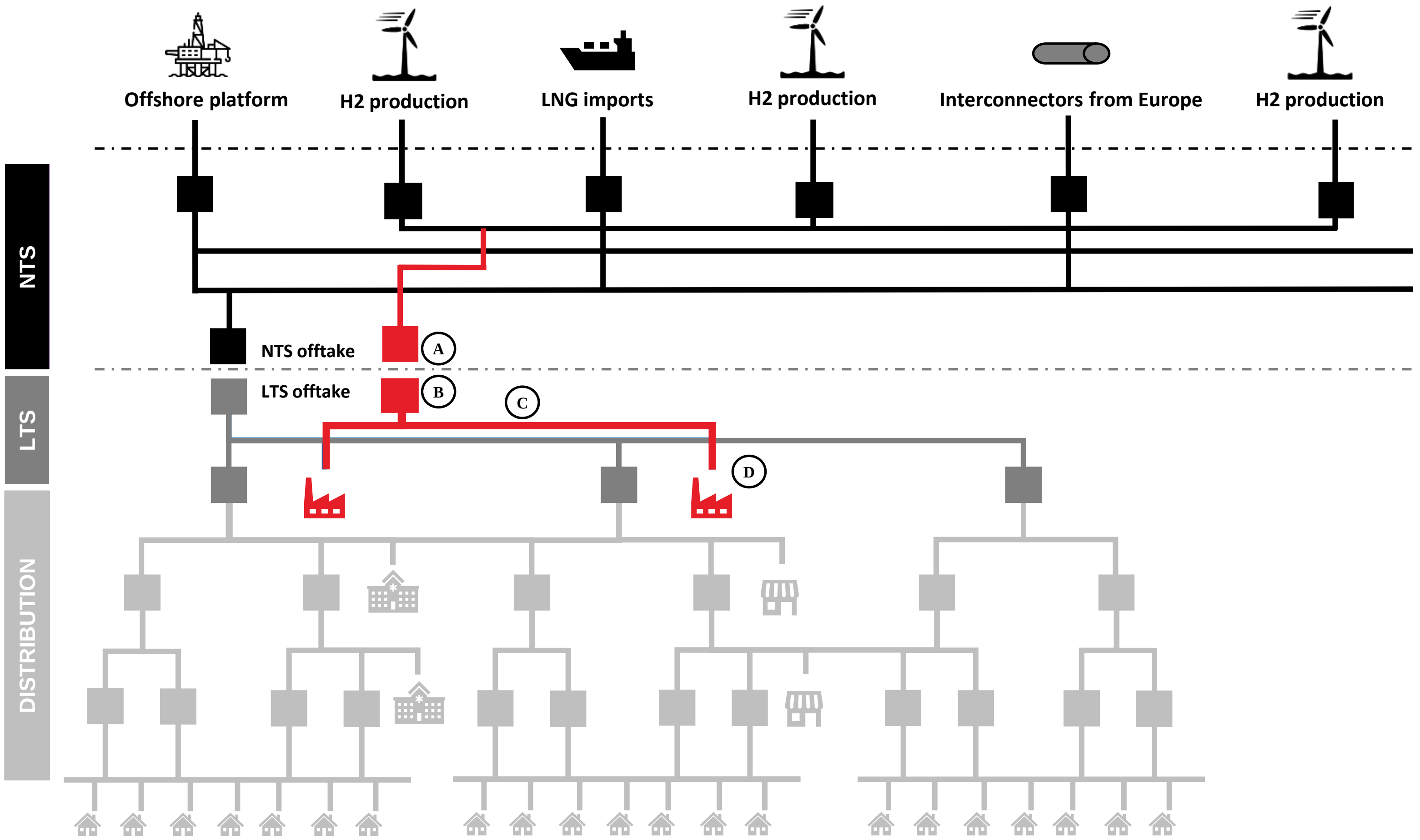
Figure 10. NTS hydrogen backbone

Source: Arup analysis

ARUP

6.5 | Balanced Hydrogen scenario

Step 2. H2 backbone into the distribution layer to convert major industry



2a New NTS offtake

2b New gas entry points (LTS Offtakes)

2c LTS new build to extend the hydrogen backbone into the distribution layer to connect major industrial customers

2d Industrial customer transition (including modification / replacement of associated governor)

6.5 | Balanced Hydrogen scenario

Hydrogen LTS backbone capex

Assumptions

As per the methodology, a hydrogen backbone equivalent to 30% of the existing LTS is required to transition industrial customers and enable the domestic transition at scale. Modelling assumptions include:

- 3,478 km of pipeline, assumed to be laid in parallel to the existing LTS.
- 35 new NTS offtakes compressor units, assumed to be constructed adjacent to existing offtakes, equivalent to 30% of the existing fleet.
- 39 new LTS gas entry points, assumed to be constructed adjacent to existing entry points, equivalent to 30% of the existing fleet.

Timing

- As per the scenario, industrial demand outside of the clusters rapidly develops in the mid 2030s, with a backbone required by mid-late 2030s to transition industrial customers and then enable domestic conversion.
- Given the scale of this infrastructure deployment, the project team assumed a period of 10 years is required, resulting in spend starting in 2027.

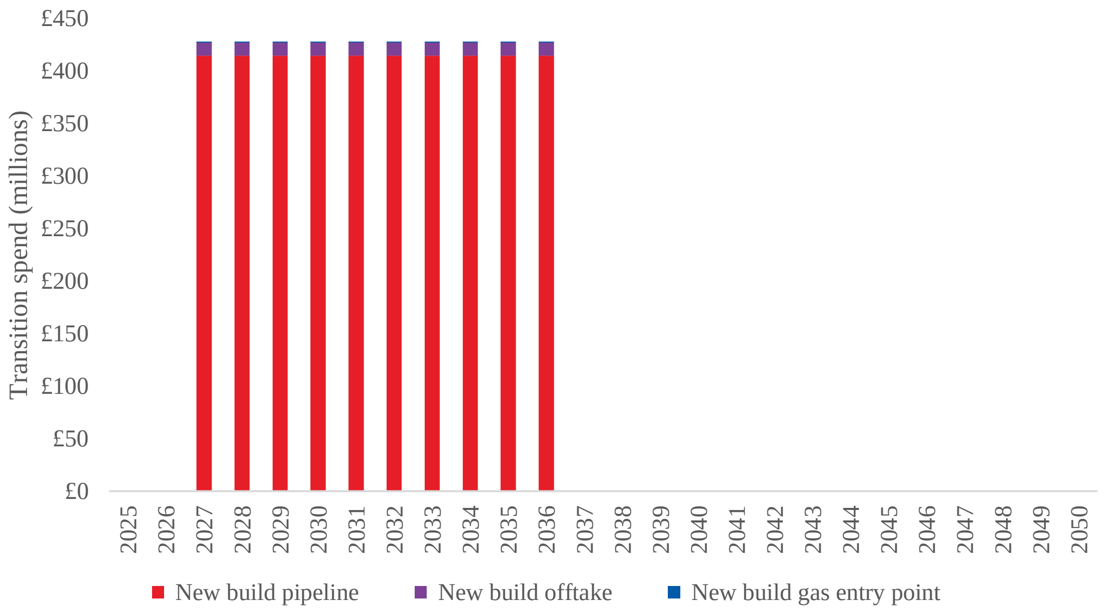


Figure 11. LTS hydrogen backbone

Source: Arup analysis

6.5 | Balanced Hydrogen scenario

Industrial customer transition capex

Assumptions

As per the methodology, industrial demand for hydrogen starts in the 2030s. Modelling assumptions include:

- 80% of the industrial customers transition to hydrogen
- As per section 6 of this report, pressure reduction equipment is deemed to be hydrogen ready (with light modification) beyond 2020. By 2032, 40% of all pressure reduction equipment in circulation will need modification, with 60% requiring replacement:
    - Non domestic governors; 4,729 units replaced, 3,153 units modified

Timing

- As per the scenario, industrial transition happens from early 2030s onwards.

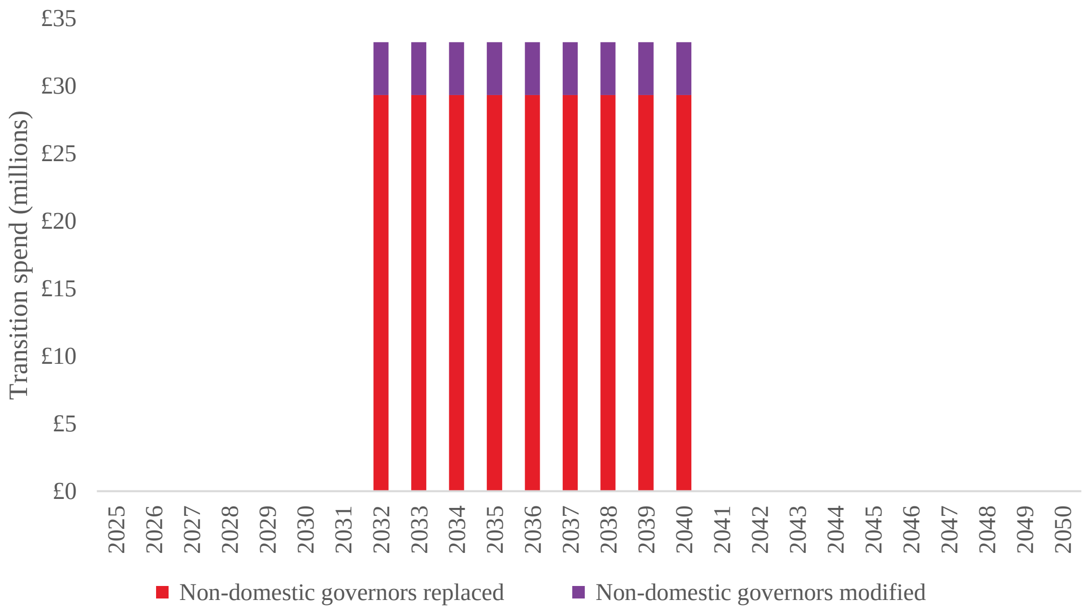


Figure 12. Industrial customer transition

Source: Arup analysis

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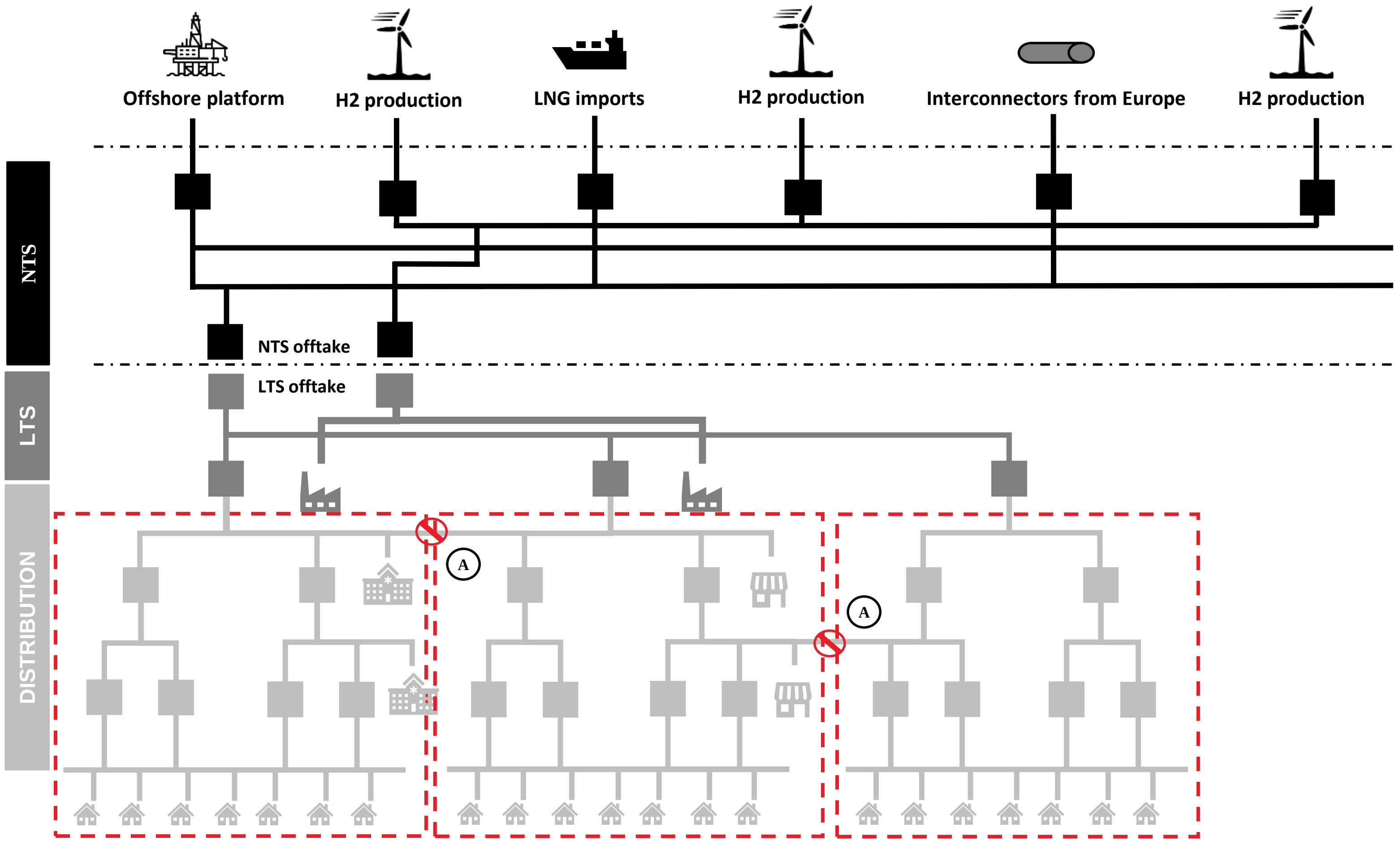
6.5 | Balanced Hydrogen scenario

Step 3. Network segmentation

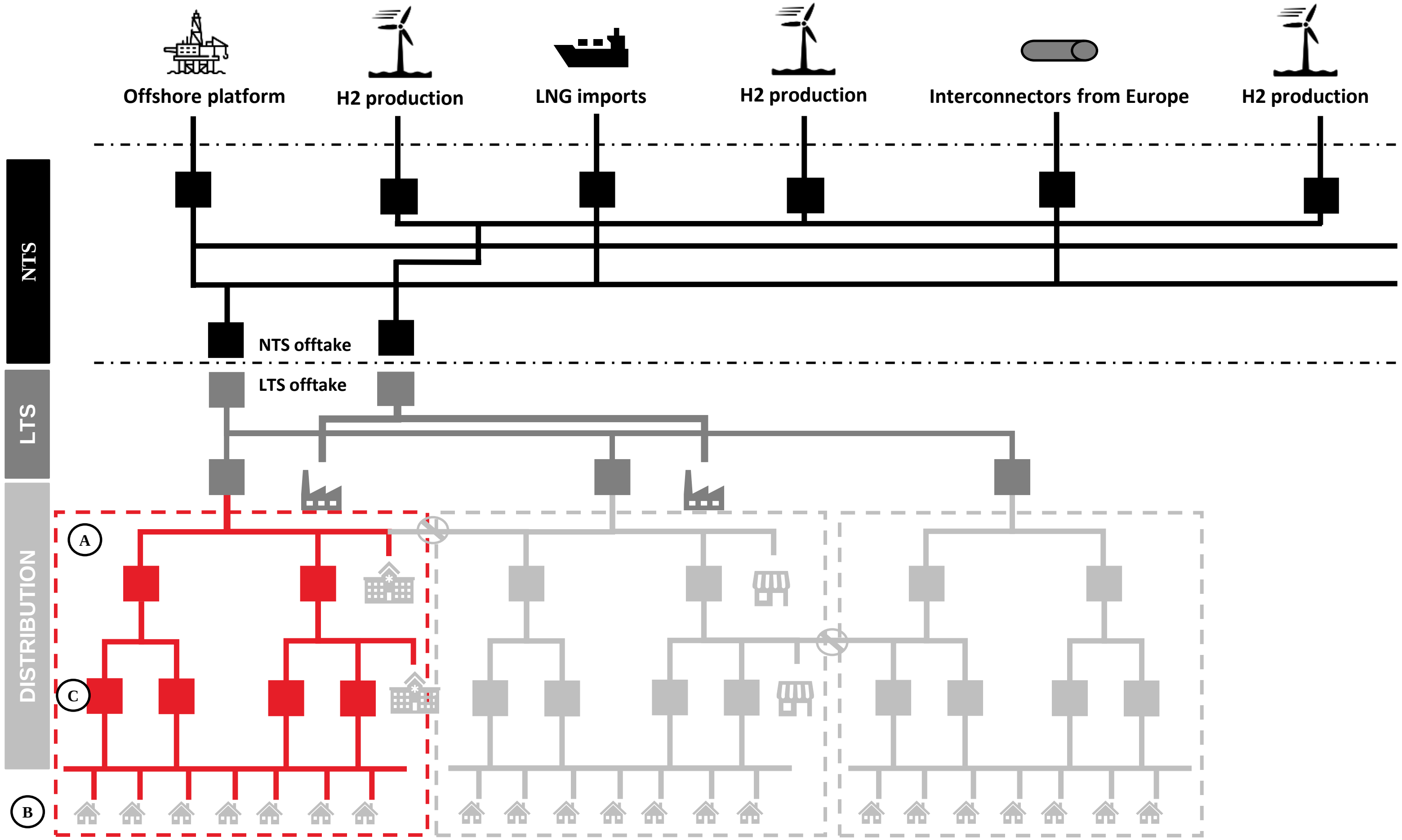


3a

De-meshing of the distribution network using sectorisation valves. This needs to happen before GDN enabling works to allow a more targeted IMRRP work programme.

6.5 | Balanced Hydrogen scenario

Step 4. GDN enabling works (restricted to hydrogen areas)



4a Non-PE mains replacement (as per HSE guidance)

4b Non- PE Service Lines pipeline replacement (as per HSE guidance)

4c Governor modification/replacement to make hydrogen ready

6.5 | Balanced Hydrogen scenario

Distribution network enabling works capex

Assumptions

Domestic demand for hydrogen starts in 2036, requiring the distribution networks to be made ready by 2040, for the network segments that are transitioning to hydrogen.

448 of the 1,380 network segments transition to hydrogen. Note the project team have assumed that the penetration rate is 50% of the current rate. This is to reflect overall market trends towards customer electrification:

- 100% of the remaining, non-PE mains are replaced, equivalent to 3,648km
- 100% of the remaining non-PE services are replaced, equivalent to 259,429 services
- As per section 6 of this report, pressure reduction equipment is deemed to be hydrogen ready (with light modification) beyond 2020. By 2032, 40% of all pressure reduction equipment in circulation will need modification, with 60% requiring replacement:
    - PRSs; 269 units replaced; 179 units modified
    - District governors; 4,239 units replaced; 6,883 units modified
    - Service governors; 20,684 units replaced; 13,790 units modified

Timing

- As per the scenario, domestic transition happens from late 2030s onwards.
- This work is assumed to happen post 2032 (when the existing mains replacement programme has finished).
- The GDNs are assumed to take a targeted approach to these works, enabling some segments to be ready for hydrogen from 2036 onwards.

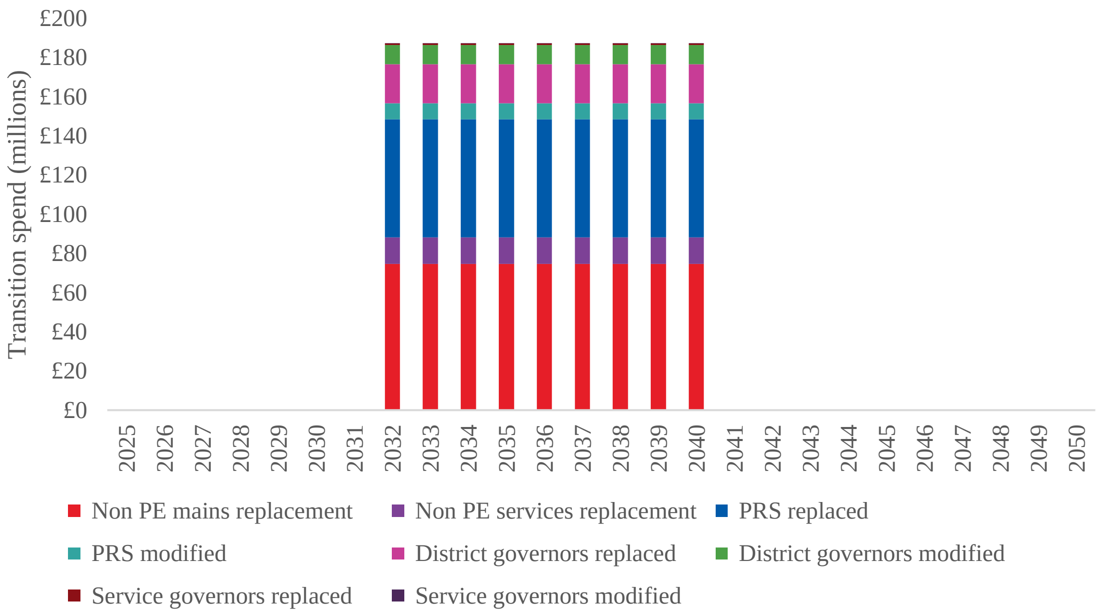


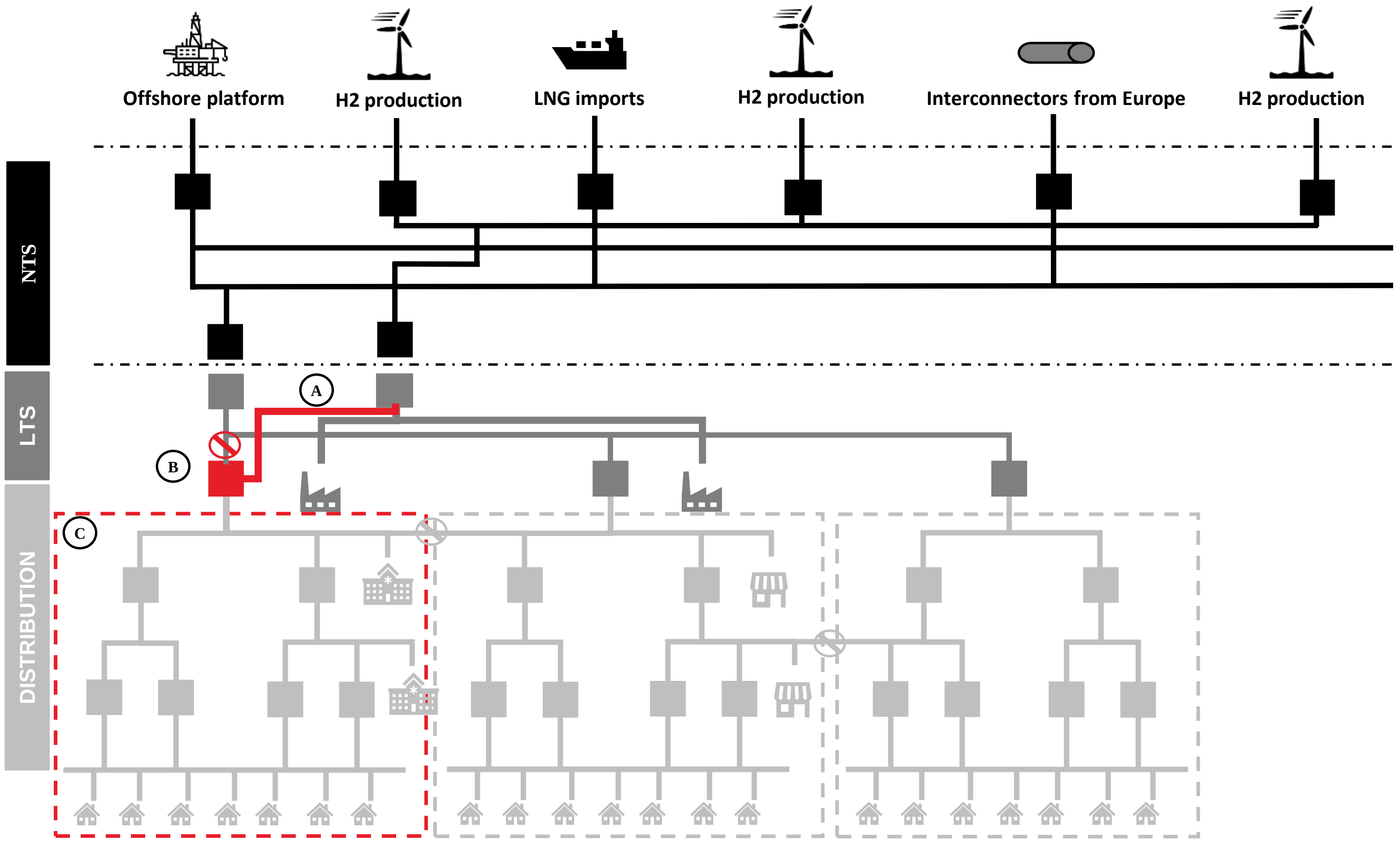
Figure 13. Distribution network enabling works

Source: Arup analysis

ARUP

6.5 | Balanced Hydrogen scenario

Step 5. H2 for domestic heat in segments



5a New LTS spur into the PRS

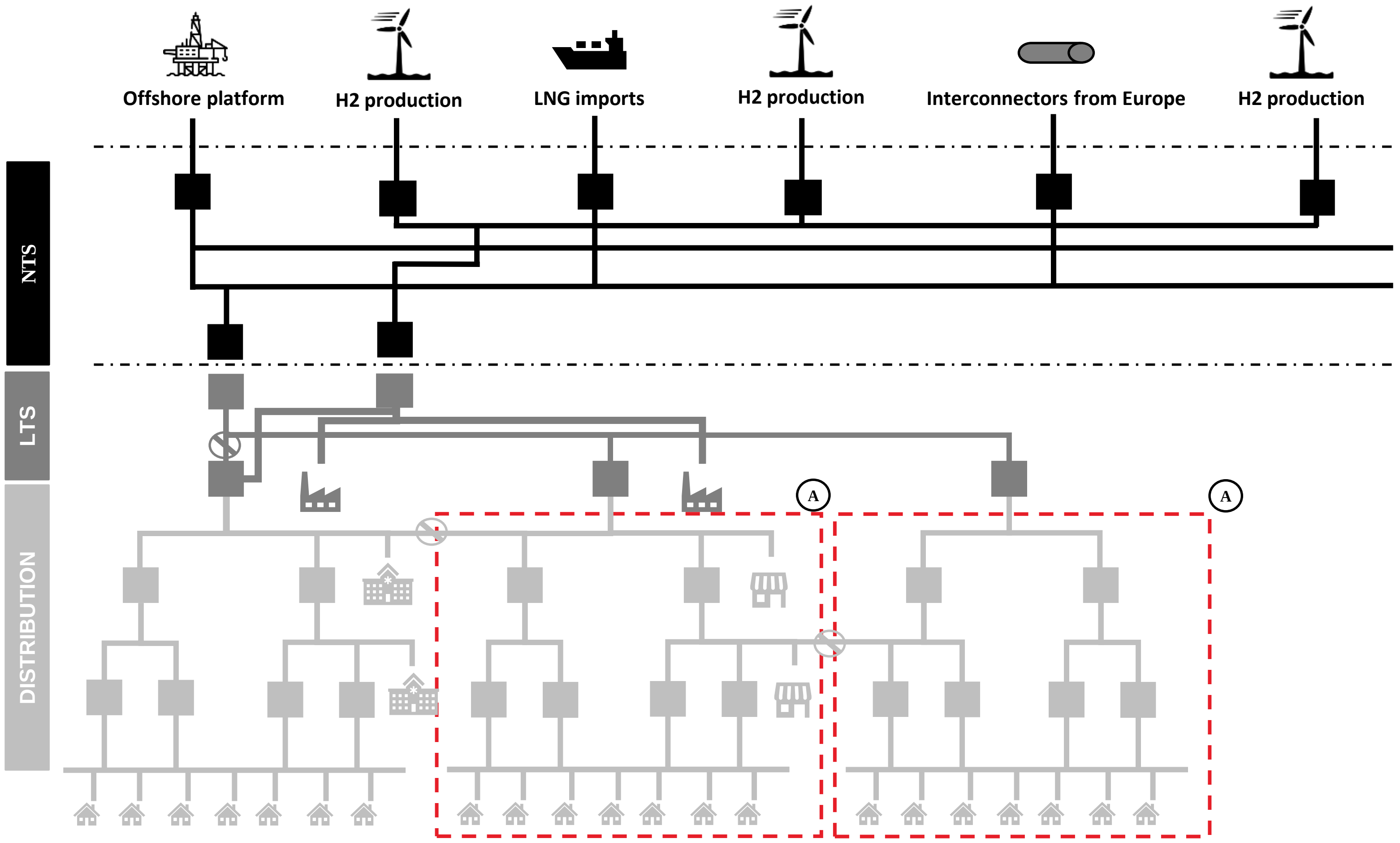
5b Modification / replacement of PRS to make hydrogen ready

5c Network segment transitioned to hydrogen

ARUP

6.5 | Balanced Hydrogen scenario

Step 6. Customer transition in non hydrogen segments



6a

Entire regions of the network transitioned away from gas

6.5 | Balanced Hydrogen scenario

Domestic customer transition capex

Assumptions

As per the scenario, the majority of customer transition to hydrogen is limited to the network segments closest to the hydrogen backbone. Modelling assumptions include:

- 100% of the distribution network has the methane removed, but only 448 network segments (1,380 total segments) replace this with hydrogen. The other segments are decommissioned
- c.18m customers are disconnected from the gas system. Note as this is now part of a programme of works, a 20% efficiency factor has been applied to the weighted average unit costs currently quoted by the GDNs
- 6m customers transition to hydrogen

Network transition costs include the labour and equipment required to remove the residual methane in the network

Timing

- As per the scenario, customer transition occurs from 2036 onwards

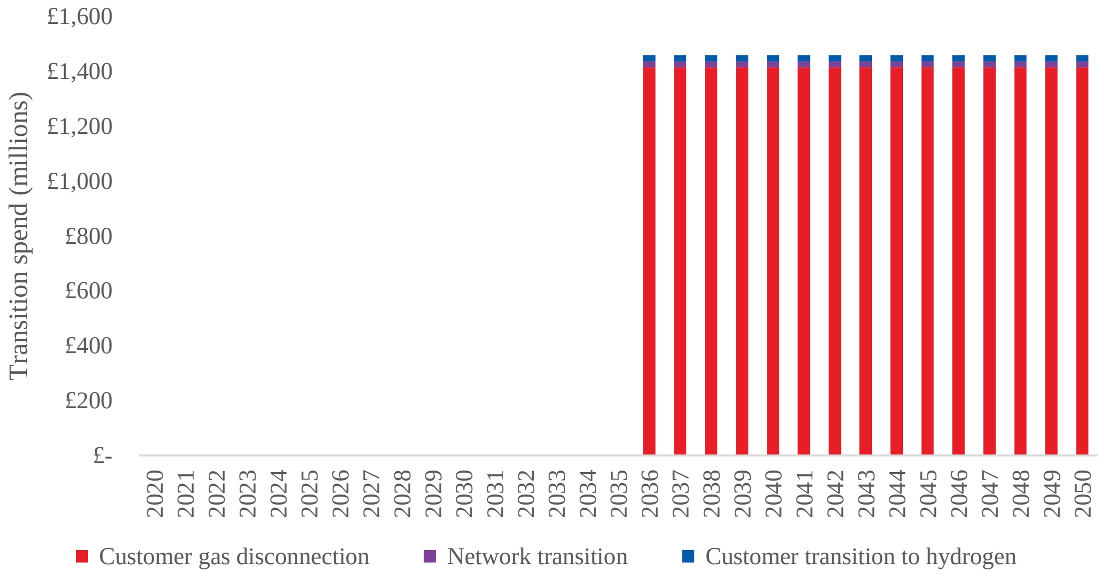


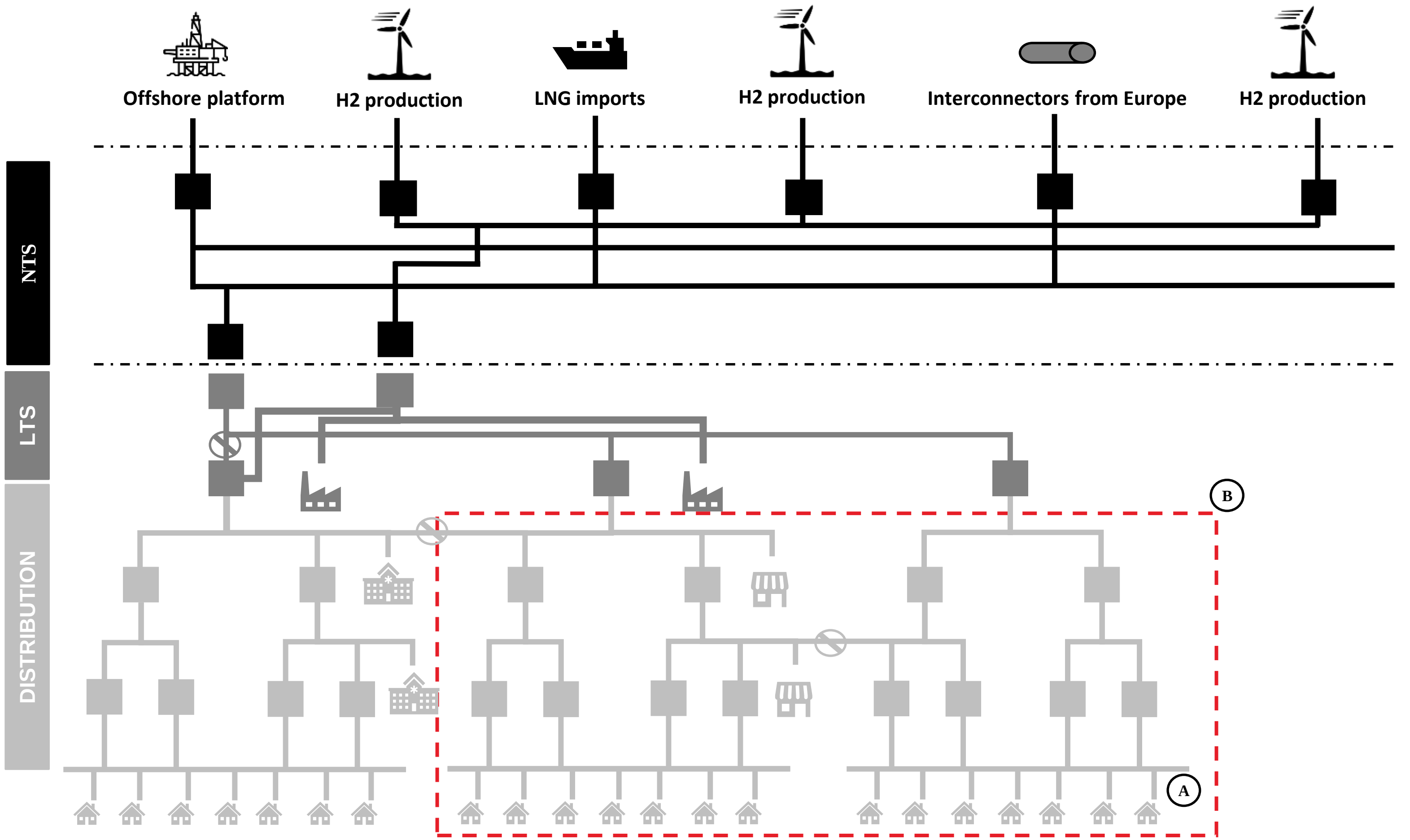
Figure 14. Domestic customer transition

Source: Arup analysis

ARUP

6.5 | Balanced Hydrogen scenario

Step 7. Deenergising and mothballing of non hydrogen segments



7a

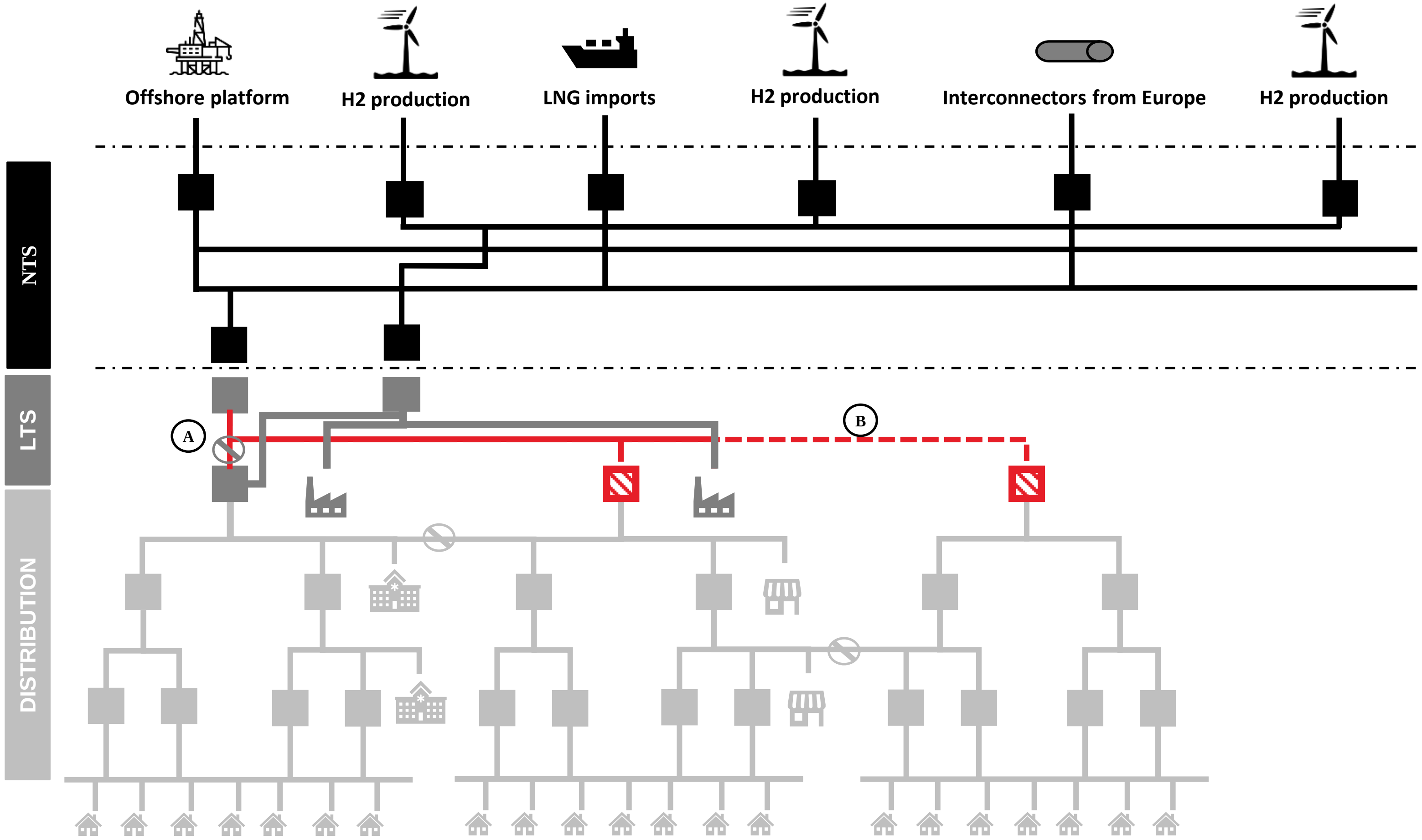
Customers permanently disconnected from the network, existing gas infrastructure within the home removed

7b

Network segments deenergised; all natural gas removed from the system, network filled with air and capped at strategic locations

6.5 | Balanced Hydrogen scenario

Step 8. LTS selectively repurposed and integrated into the LTS hydrogen backbone



8a Where there is no more natural gas demand, the LTS can be purged of natural gas and selectively repurposed

8b Not all of the LTS is repurposed, with part of this network deenergised and decommissioned for other purposes such as storage.

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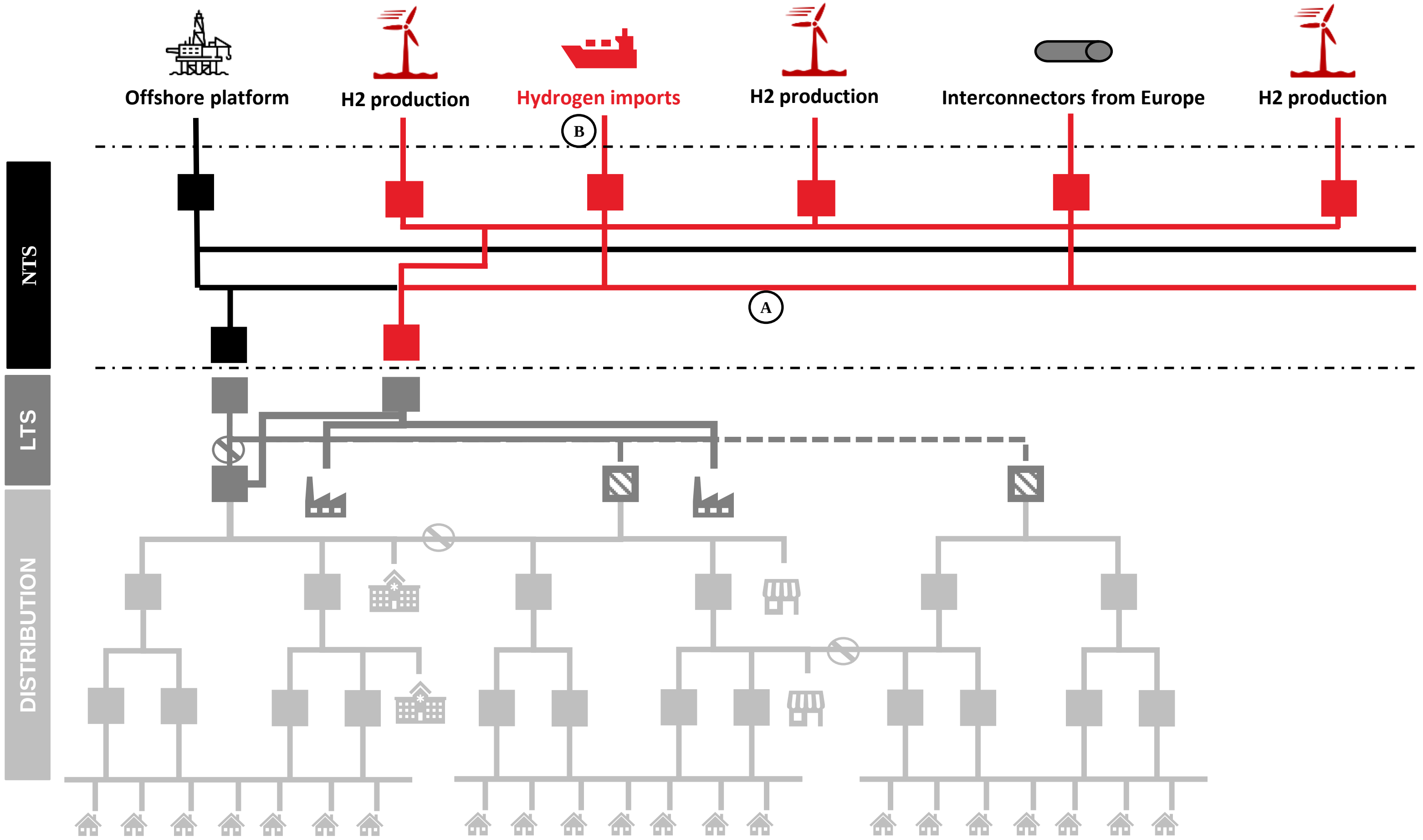
6.5 | Balanced Hydrogen scenario

Step 9. NTS selectively repurposed and integrated into the hydrogen backbone



9a
NTS is selectively repurposed and integrated into the hydrogen backbone

9b
Strategic injection points are repurposed for additional security of supply

6.5 | Balanced Hydrogen scenario

Repurposing (NTS and LTS) capex

Assumptions

As per the methodology, it is assumed that where practicable up to 40% of the remaining NTS and 30% of the LTS are integrated into the new hydrogen system, primarily to act as additional storage:

- This is assumed a zero cost option i.e. only pipeline that is suitable will be repurposed.
- Additional compression is assumed to not be required given the lower volumes of hydrogen demanded.

Note as per the scenario 20% of the NTS is retained for natural gas at zero cost

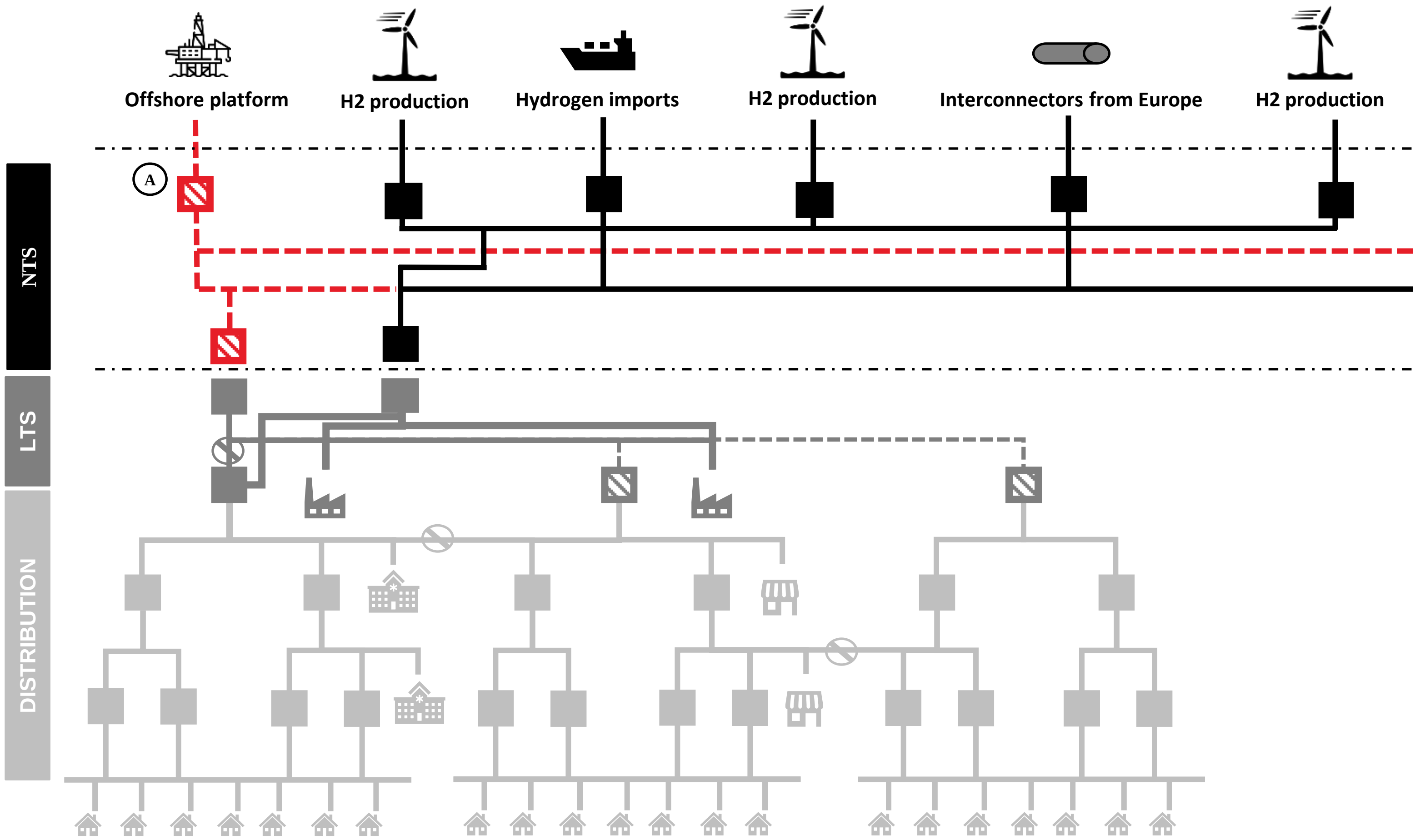
Timing

- Repurposing is assumed to be carried out as the domestic and industrial conversion frees up capacity on the natural gas system, from 2040 onwards.

ARUP

6.5 | Balanced Hydrogen scenario

Step 10. Remaining NTS decommissioned



10

NTS decommissioning – due to material type, pipeline diameter likely to require a permanent solution e.g. grouting

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6.5 | Balanced Hydrogen scenario

Decommissioning capex

Assumptions

Parts of the NTS and LTS are no longer required for either hydrogen or residual natural gas:

- 40% of the NTS is decommissioned.
- 70% of the LTS is decommissioned.
- Decommissioning unit cost is assumed at 50% of the weighted average MEAV cost for the NTS and LTS respectively.

Timing

- Decommissioning is assumed to be carried out as capacity is freed up on the system, from 2040 onwards.

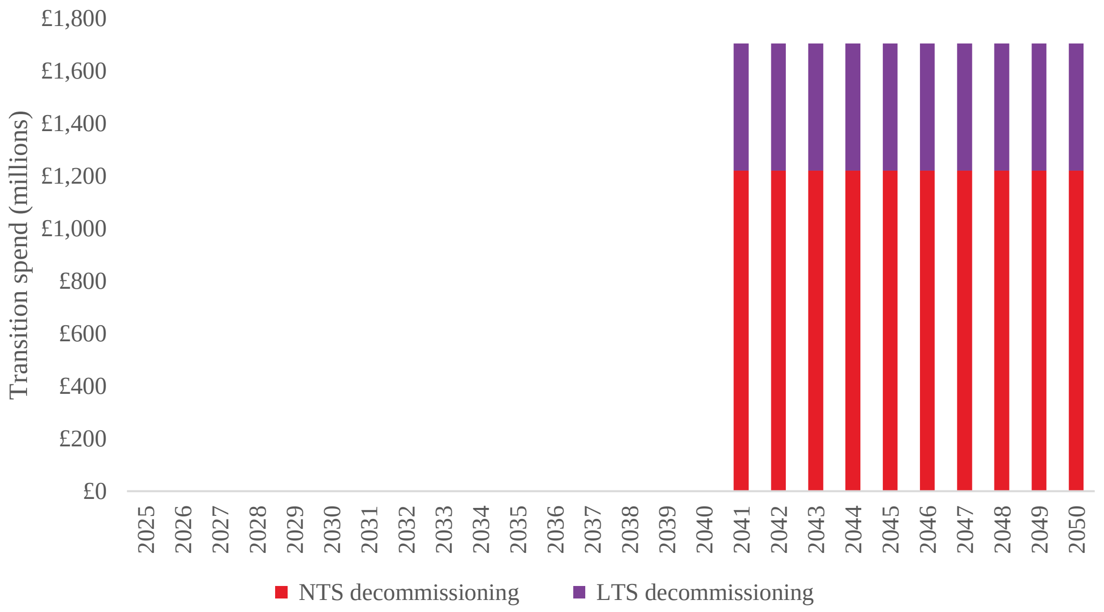


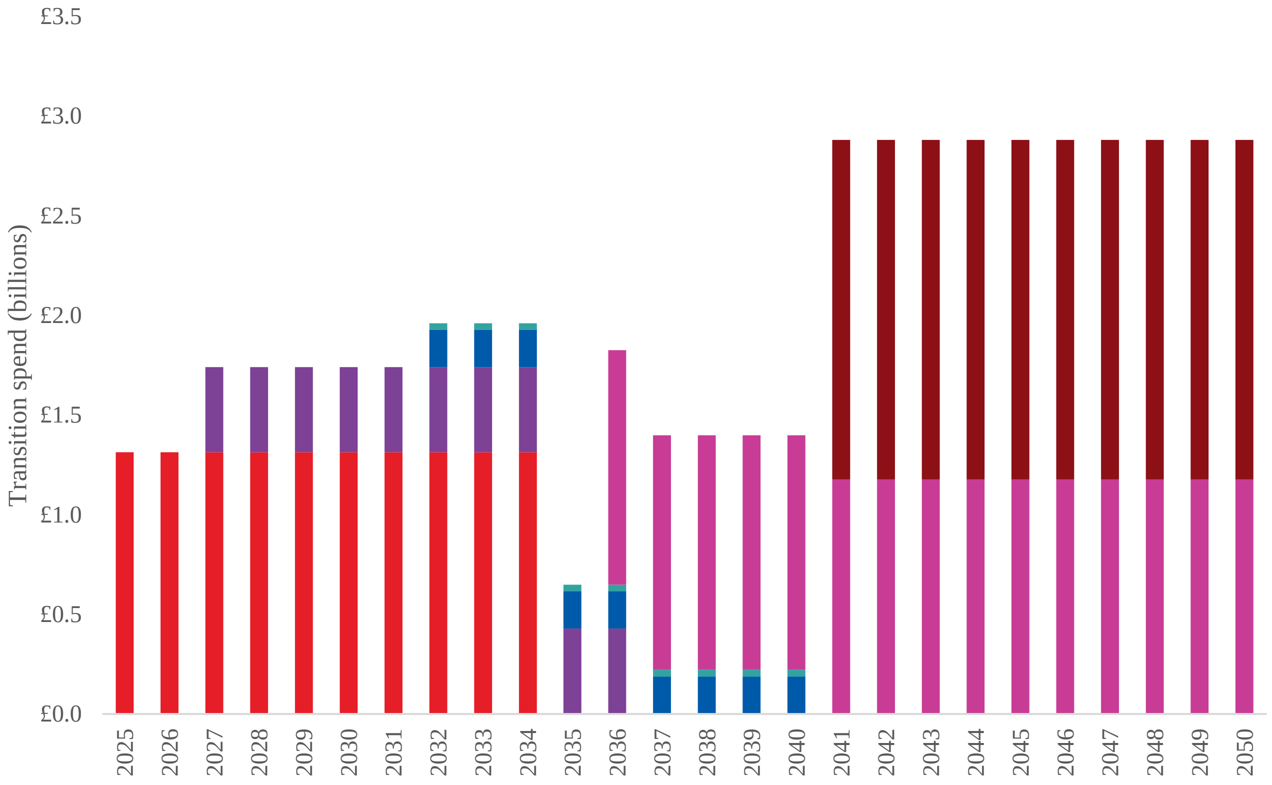
Figure 15. Decommissioning

Source: Arup analysis

6.5 | Balanced Hydrogen scenario

Overall Cost Summary

Figure 16. Summary of annual spend by category



Source: Arup analysis

Figure 21. Summary of total capex spend by category (£m)

Hydrogen NTS backbone	£	13,119	22%
Hydrogen LTS backbone	£	4,278	7%
Distribution enabling works	£	2,375	4%
Industrial customer transition	£	299	1%
Domestic customer transition	£	21,891	37%
Repurposing (NTS and LTS)	£	-	-
Decommissioning	£	17,037	29%
TOTAL	**£**	**59,000**	**100%**

6.5 | Balanced Hydrogen scenario

Summary of customer transition

The charts opposite present the domestic and minor Industrial and Commercial (I&C) customer transition (opposite, top) and the Major I&C customer transition (opposite, bottom) in the Balanced scenario:

- Major I&C customers are defined by the need for a non domestic governor less than 200scm/h, as identified in the Regulatory Reporting Packs. Such customers would likely include major industrial users of energy that are likely hard to abate e.g. glass manufacturing and would likely be connected higher up the pressure tiers of the distribution network.
- Domestic and Minor I&C customers include all other customers such as homes, small industrial and commercial units, shops, warehouses etc. and would likely be connected lower down the pressure tiers of the distribution network.
- Domestic and Minor I&C transition; of the existing c. 24m natural gas customers today, c. 6m transition to hydrogen with the majority c. 18m transitioning off the gas network on to alternative energy solutions. Note this is due to hydrogen being geographically limited to areas close to the hydrogen backbone.
- Major I&C transition; of the existing c. 9,800 natural gas customers today, 80% transition to hydrogen, with the remining customers switching to alternative energy solutions.

Figure 17. Domestic and Minor I&C customer transition

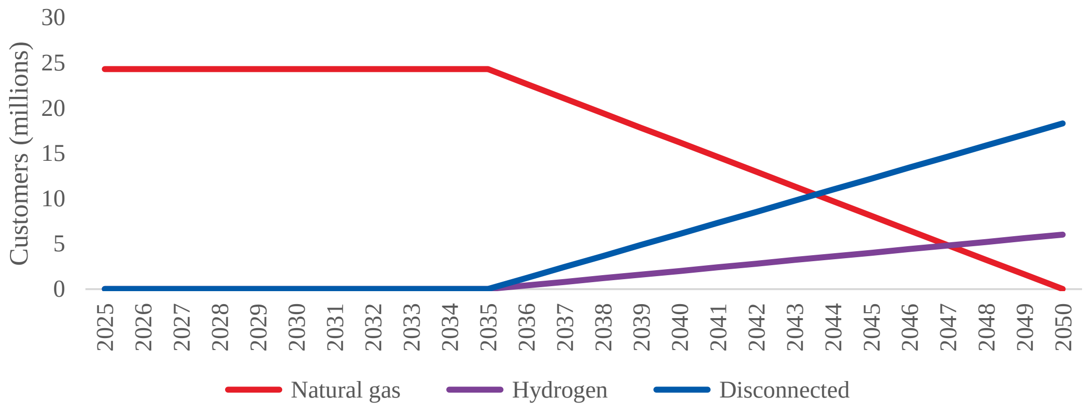
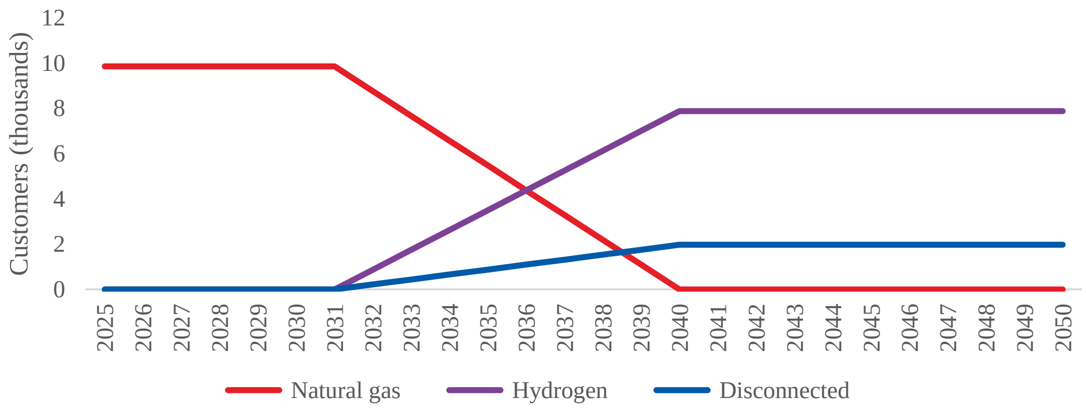


Figure 18. Major I&C customer transition



Source: Arup analysis

6.6 | Scenario-specific transition methodology

Low hydrogen scenario

ARUP

6.6 | Low Hydrogen Scenario

Scenario description (FES Consumer Transformation)

2020s

- Domestic natural gas demand begins to decline with users either reducing demand through installation of energy efficiency measures (insulation and double glazing) and/or installing heat pump as a domestic space heating solution.
- Small hydrogen demand within industrial clusters begins to develop, but remains limited by 2030.

2030s

- Significant reduction in all demands for natural gas with minimal demand remaining in 2040.
- Industrial hydrogen demand continues to increase but at a very slow pace and remains limited only to clusters.
- Growth in heat pump installations continues with conventional boiler numbers falling considerably by 2040.

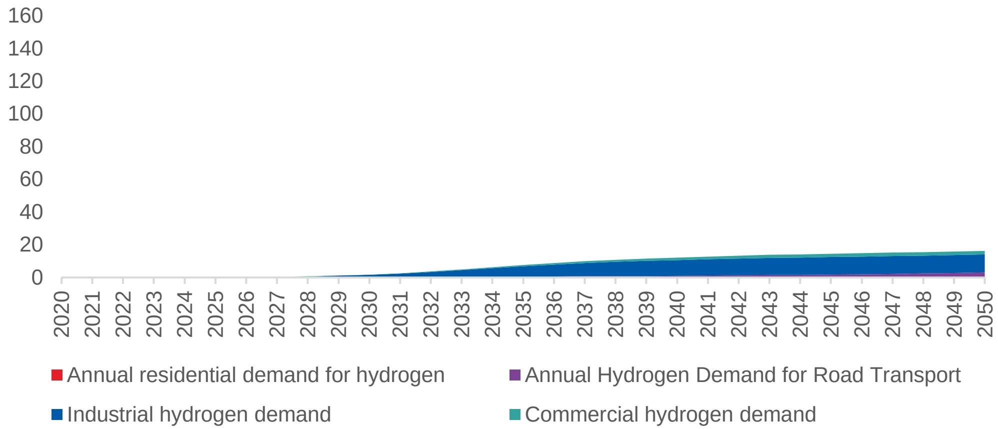
2040s

- Industrial hydrogen demand increases to 2050 but at slow rates and low overall levels - continues to be limited to clusters.
- Natural gas demand continued to decrease as heat pump installations continue to replace conventional boilers.

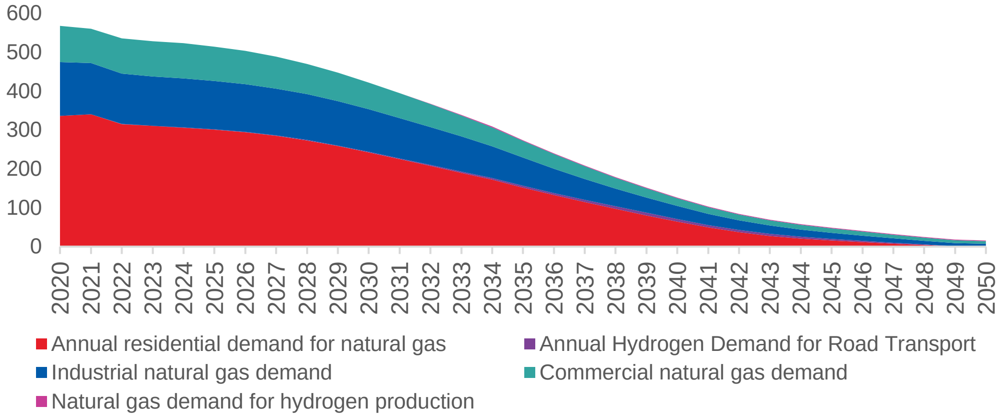
2050

- High electrified scenario with almost no natural gas demand by 2050, with some hydrogen demand in the industrial clusters for those hard to decarbonise processes.

‘Consumer Transformation’ - Hydrogen Demand (TWh)



‘Consumer Transformation’ - Natural Gas Demand (TWh)



Source: National Grid, Future Energy Scenarios [29]

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6.6 | Low Hydrogen Scenario

Translating the FES scenario into an end state for the gas network

Size of the network in this scenario

- As per the High scenario, hydrogen demand starts in the industrial clusters. Natural gas demand falls away sharply in the 2030s as domestic and industry transition.
- Similarly, to the High scenario natural gas demand is not forecast to reduce sufficiently in the short term, to increase network capability of the NTS to the point that it can be split into 2 independent systems.
- From 2030, natural gas demand in domestic and non-hard to abate industry and commercial premises falls away significantly. In order to remove the requirement for a large-scale system supporting very few customers, this project assumes that entire regions of country would transition.
  - Once customers were successfully migrated, the gas can be removed, and the network decommissioned.
  - In order to facilitate the efficient decommissioning of the network, it is likely that areas at the extremity of the system would be transitioned first, with the gas 'pushed' back up the system to the East coast.

Note as per the natural gas demand chart on the previous page, by 2050 there is some limited demand for natural gas to make hydrogen via methane reformation (c. 2 TWh).

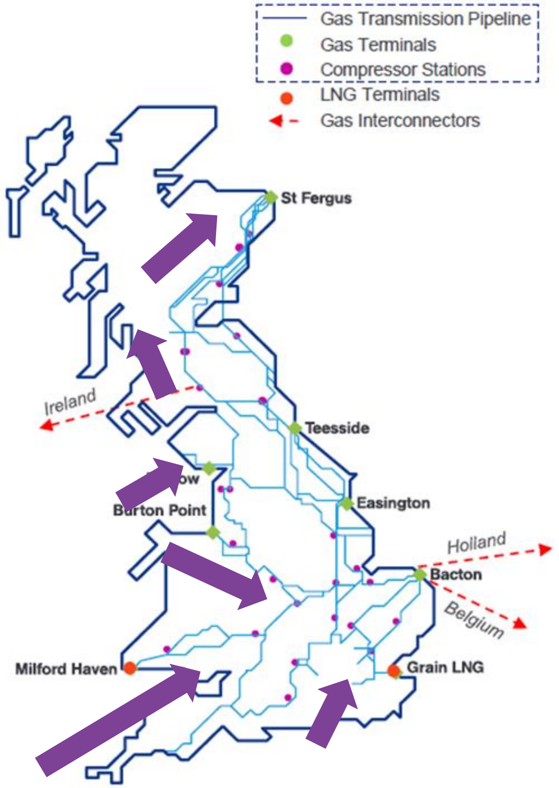
Timing impact of network development on the scenario demand and production

The timings of demand and production are unchanged from the FES scenario.

Residual natural gas network

It is anticipated that there will be some, albeit small, residual demand for natural gas by 2050. This is assumed to be in the clusters for blue hydrogen generation, with associated CCUS. Accordingly, our analysis has suggested that 20% of the NTS to accommodate this demand.

National Gas Transmission System



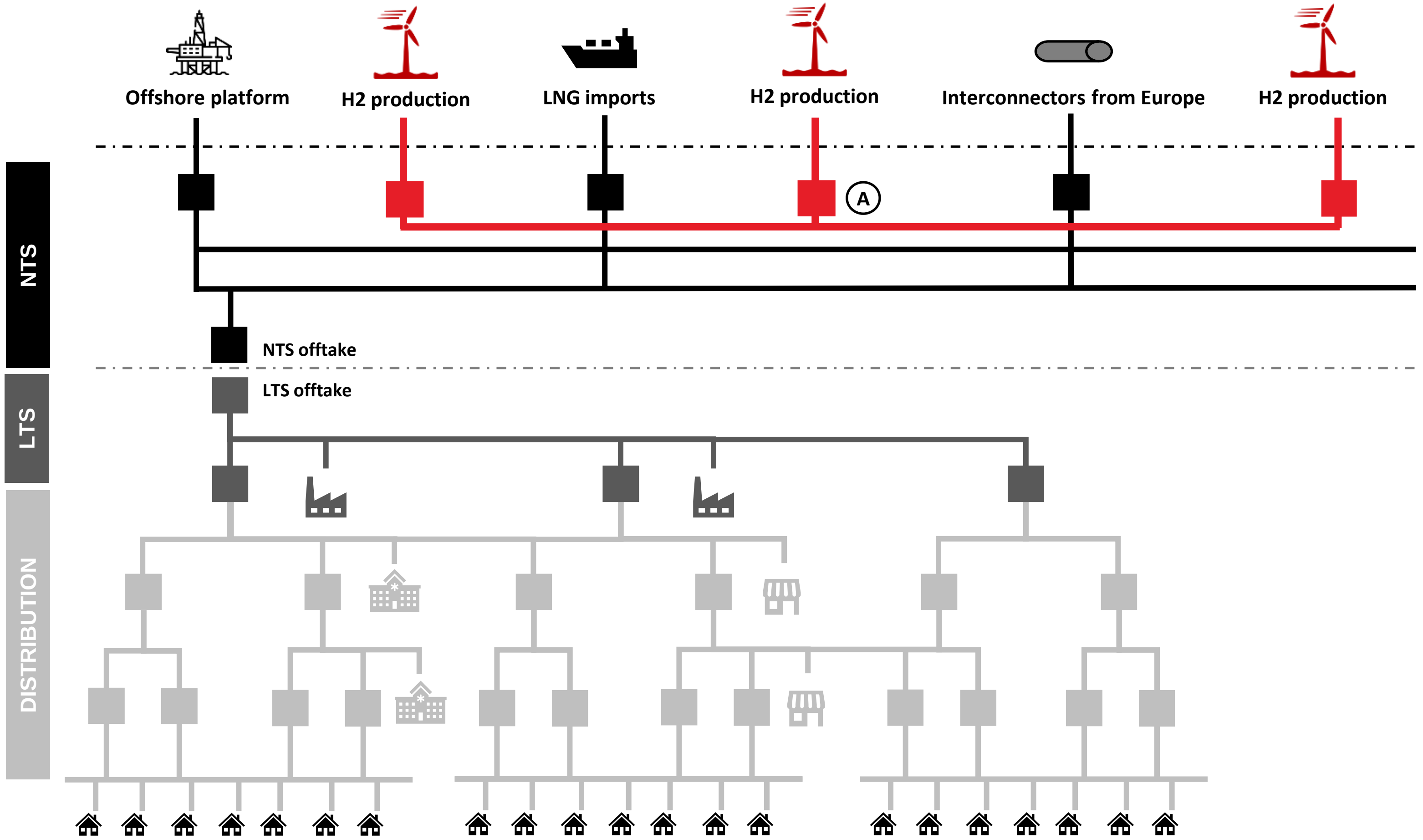
Natural gas 'pushed' back to the network injection points, to facilitate an efficient deenergising of the network and decommissioning.

Source: Arup analysis

ARUP

6.6 | Low Hydrogen Scenario

Step 1. Hydrogen NTS Backbone



1a New build hydrogen NTS build

1a New hydrogen ready compressors built for the hydrogen backbone

1a New injection points to support the new hydrogen backbone

ARUP

6.6 | Low Hydrogen Scenario

Hydrogen NTS backbone capex

Assumptions

As per the methodology, a hydrogen backbone equivalent to 20% of the existing NTS is required. Modelling assumptions include:

- 1,525 km of pipeline, assumed to be laid in parallel to the existing NTS, equivalent to 20% of the existing NTS.
- 14 compressor units, assumed to be constructed at existing compressor stations, equivalent to 20% of the existing compressor fleet.
- 7 NTS injection points, one assumed for each of the clusters and an additional one at Bacton for European interconnectivity.

Timing

- As per the scenario, industrial demand in the clusters rapidly develops in the early 2030s, with a backbone required by 2035.
- Given the scale of this infrastructure deployment, the project team assumed a period of 10 years is required, resulting in spend starting in 2025.

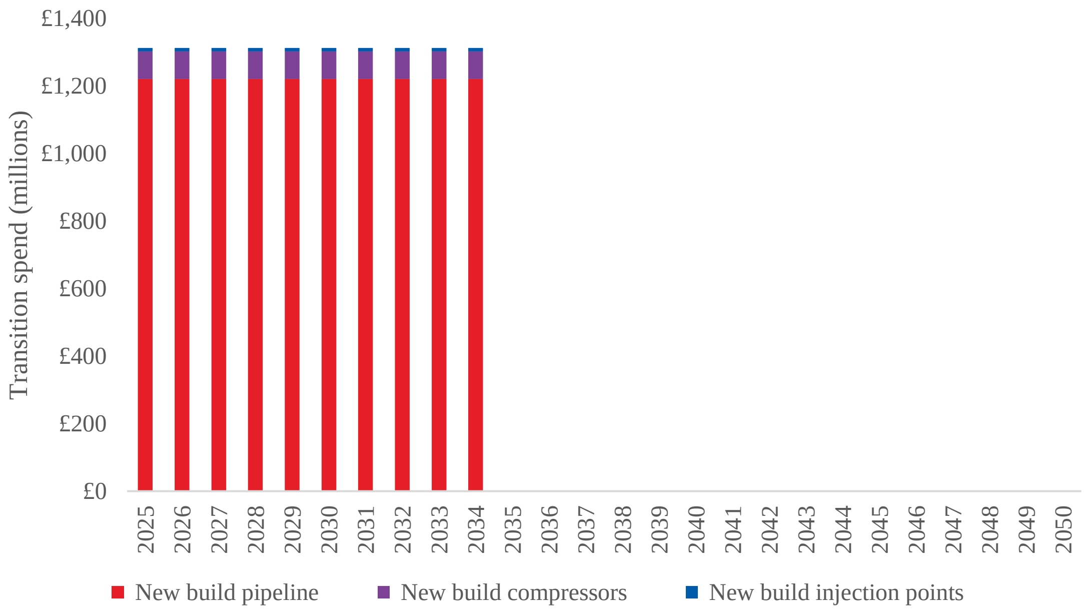
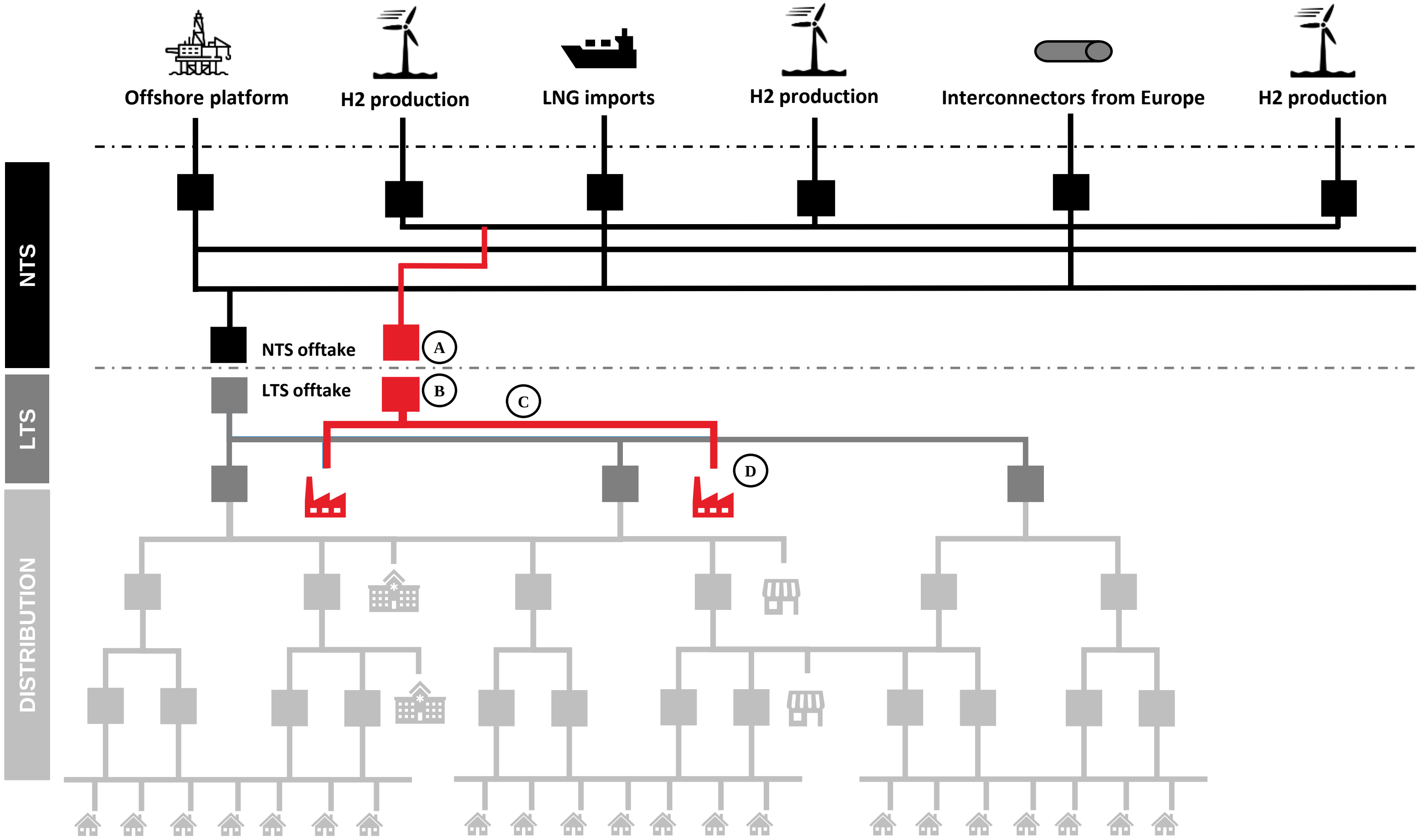


Figure 19. NTS hydrogen backbone

Source: Arup analysis

6.6 | Low Hydrogen Scenario

Step 2. H2 backbone into the distribution layer to convert major industry



2a	New NTS offtake
2b	New gas entry points (LTS Offtakes)
2c	LTS new build to extend the hydrogen backbone into the distribution layer to connect major industrial customers
2d	Industrial customer transition (including modification / replacement of associated governor)

ARUP

6.6 | Low Hydrogen Scenario

Hydrogen LTS backbone capex

Assumptions

As per the methodology, a hydrogen backbone equivalent to 20% of the existing LTS is required in order to transition industrial and commercial customers. Modelling assumptions include:

- 2,318 km of pipeline, assumed to be laid in parallel to the existing LTS, equivalent to 20% of the existing NTS.
- 24 new NTS offtakes, assumed to be constructed adjacent to existing offtakes, equivalent to 20% of the existing fleet.
- 26 new LTS gas entry points, assumed to be constructed adjacent to existing entry points, equivalent to 20% of the existing fleet.

Timing

- As per the scenario, industrial demand outside of the clusters rapidly develops in the mid 2030s, with a backbone required by mid-late 2030s to transition industrial customers.
- Given the scale of this infrastructure deployment, the project team assumed a period of 10 years is required, resulting in spend starting in 2027.

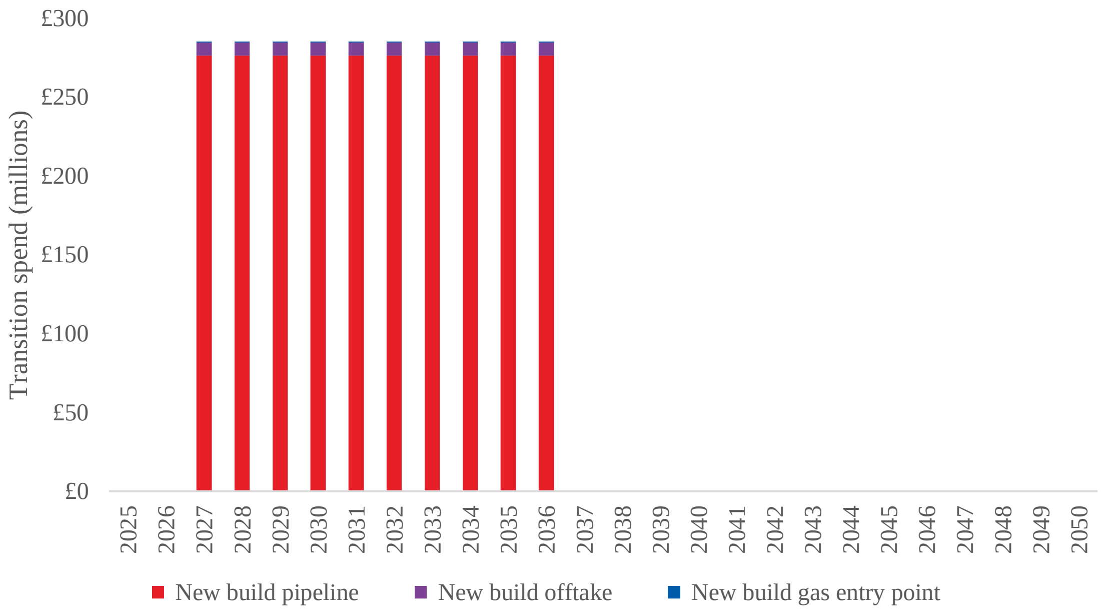


Figure 20. LTS hydrogen backbone

Source: Arup analysis

Distribution network enabling works

Assumptions

As per the methodology, there is no domestic demand for hydrogen. As a result no distribution network enabling works are required.

6.6 | Low Hydrogen Scenario

Industrial customer transition capex

Assumptions

Modelling assumptions include:

- 60% of the industrial customers transition to hydrogen.
- As per section 6 of this report, pressure reduction equipment is deemed to be hydrogen ready (with light modification) beyond 2020. By 2032, 40% of all pressure reduction equipment in circulation will need modification, with 60% requiring replacement:
    - Non domestic governors; 3,547 units replaced, 2,364 units modified

Timing

- As per the scenario, industrial transition happens from early 2030s onwards.

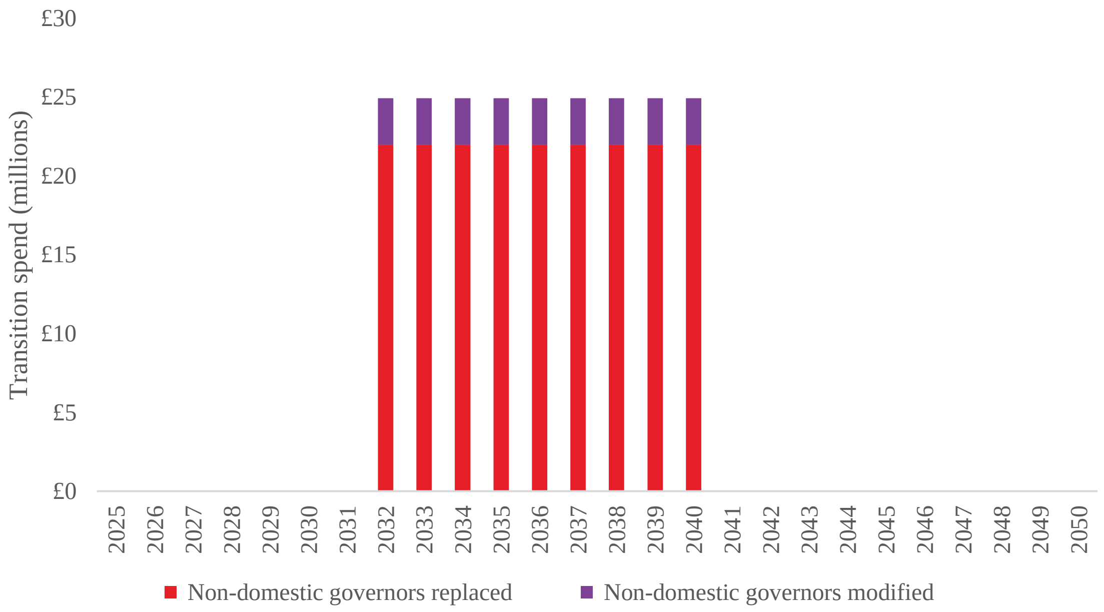


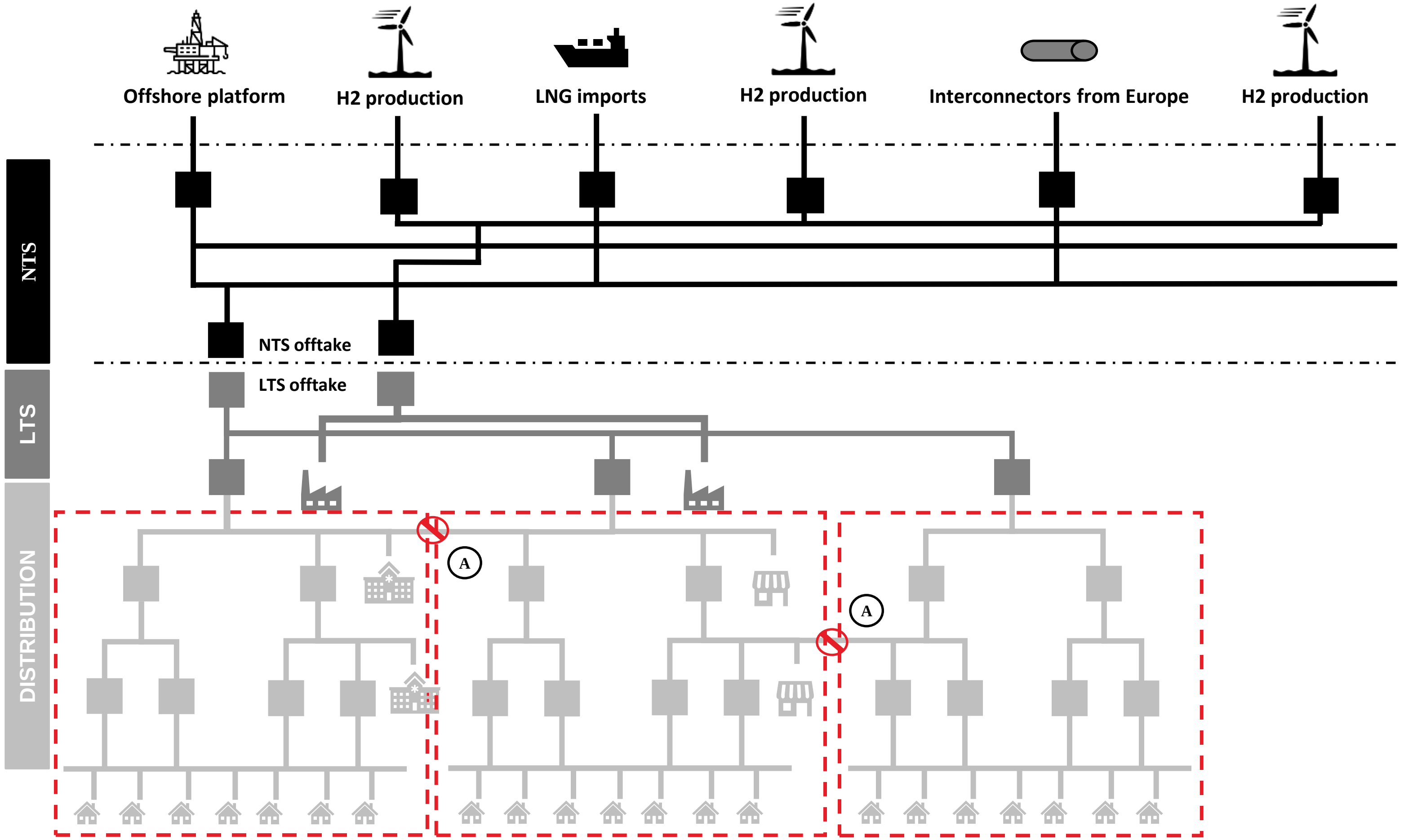
Figure 21. Industrial customer transition

Source: Arup analysis

ARUP

6.6 | Low Hydrogen Scenario

Step 3 Network segmentation



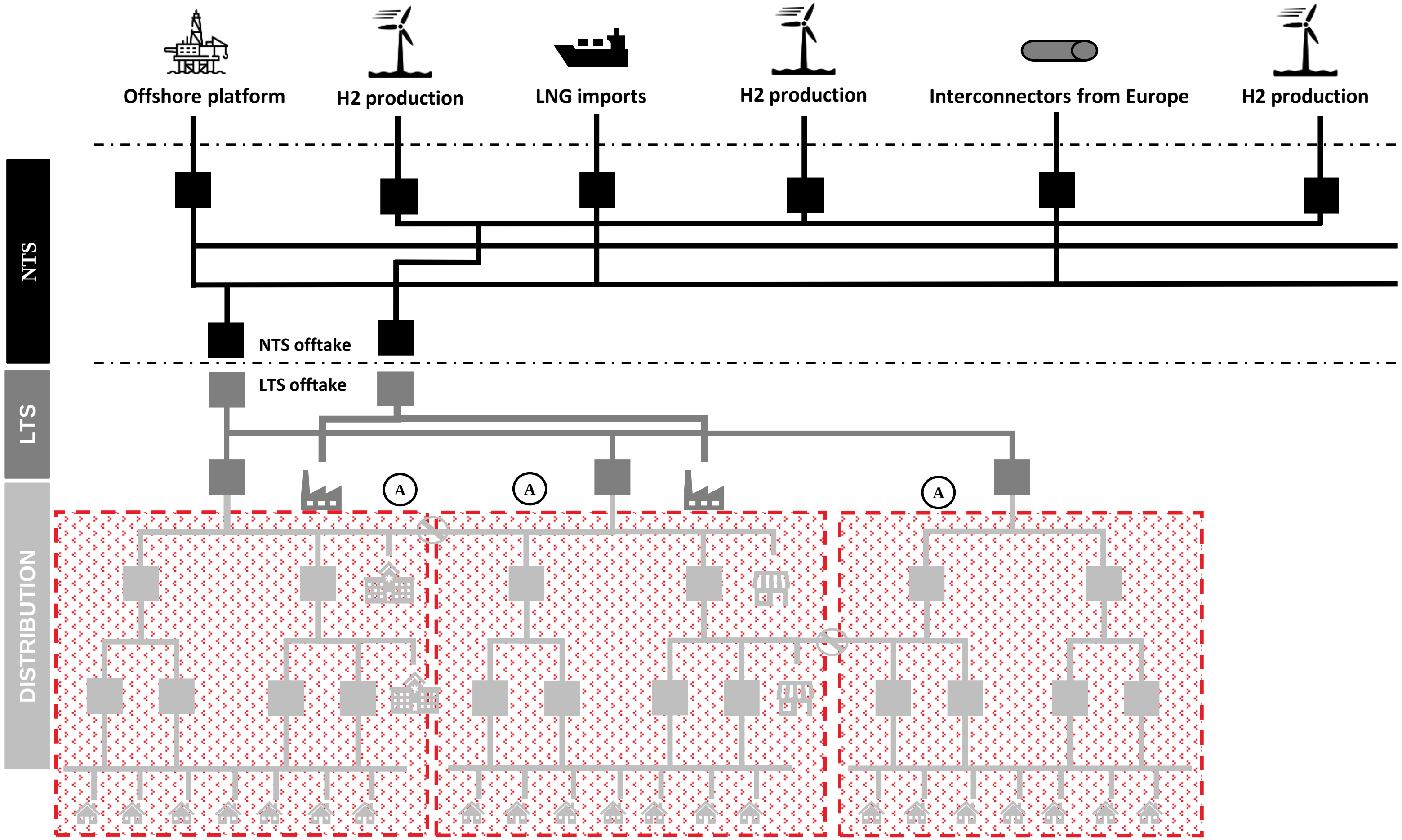
3a

De-meshing of the distribution network using valves.

ARUP

6.6 | Low Hydrogen Scenario

Step 4i. Customer transition in segments

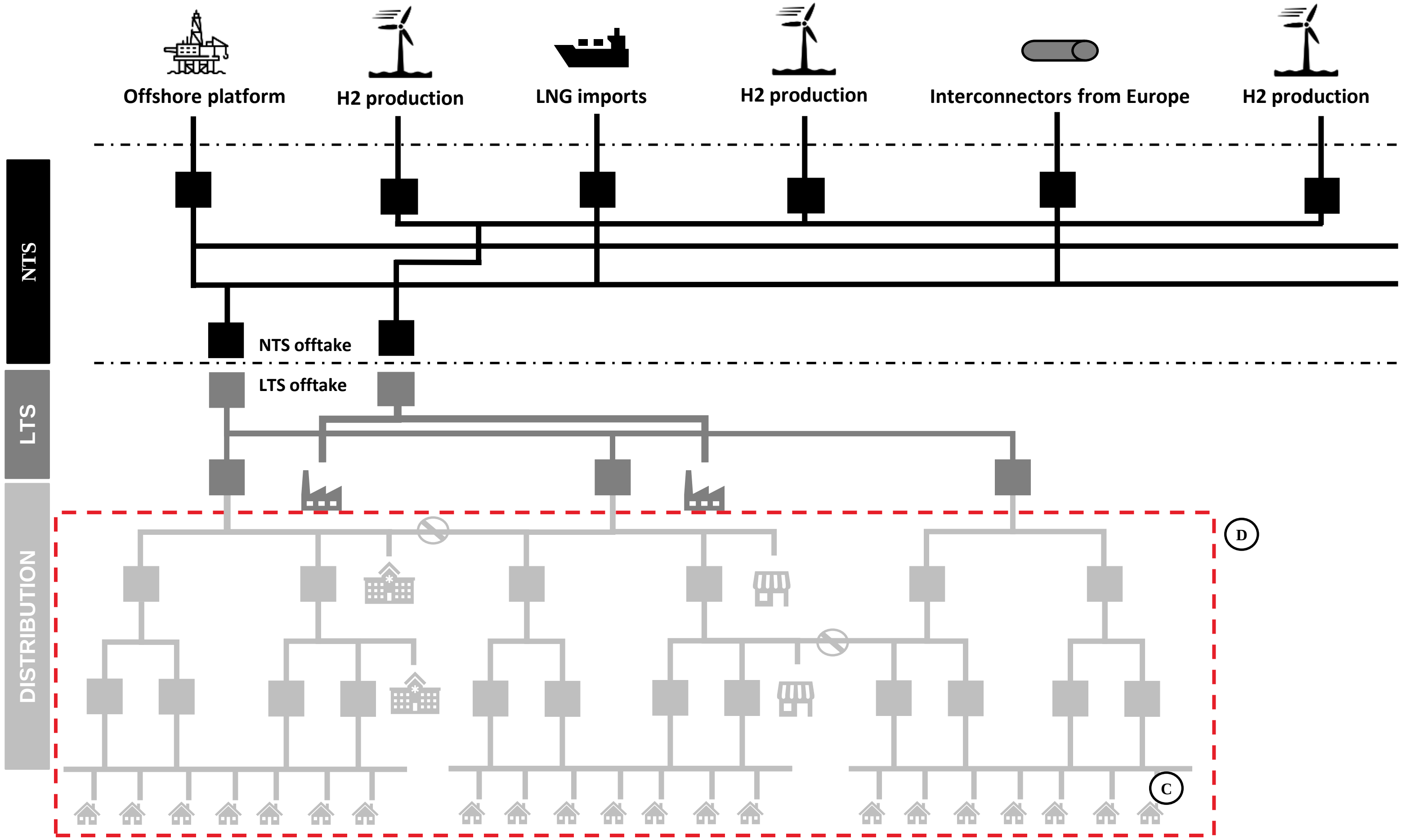


4a

Entire regions of the network transitioned away from gas.

6.6 | Low Hydrogen Scenario

Step 4ii. Deenergising and mothballing of the distribution network



4c Customers permanently disconnected from the network, existing gas infrastructure within the home removed

4d Network segments deenergised; all natural gas removed from the system, network filled with air and capped at strategic locations. This will involve some works at customers homes that are outside of this scope.

6.6 | Low Hydrogen Scenario

Domestic customer transition capex

Assumptions

100% of domestic customers are disconnected. Modelling assumptions include:

- 100% of the LP distribution network has the methane removed, 0 segments are reinjected with hydrogen and the whole distribution layer is decommissioned (see later).
- 24.3m customers are disconnected from the gas system. Note as this is now part of a programme of works, a 20% efficiency factor has been applied to the weighted average unit costs currently quoted by the GDNs.

Network transition costs include the labour and equipment required to remove the residual methane in the network

Timing

- Customer transition occurs from 2031 onwards.

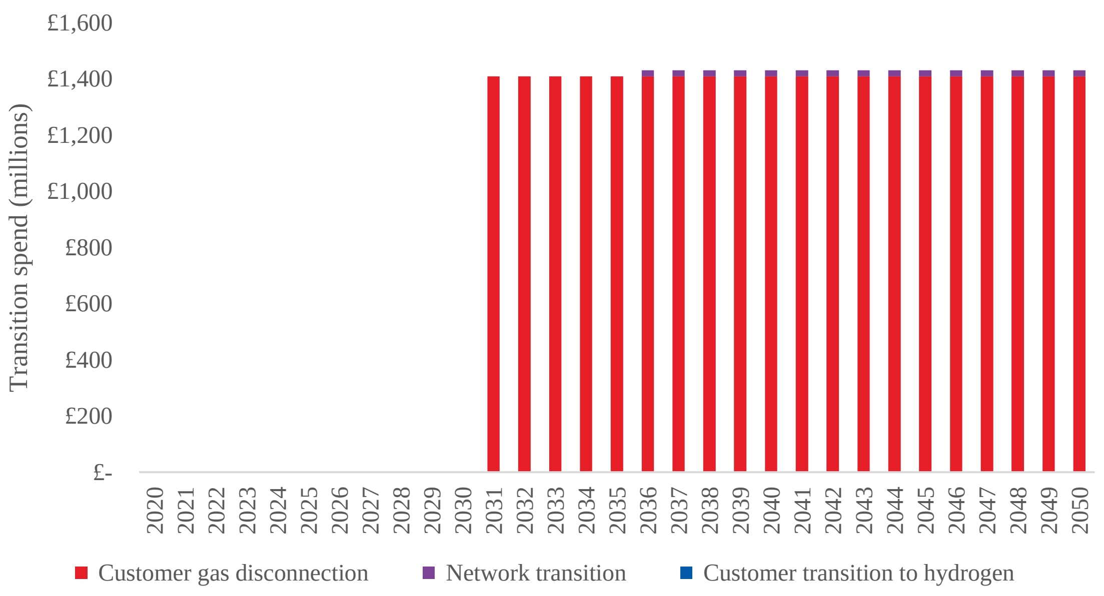


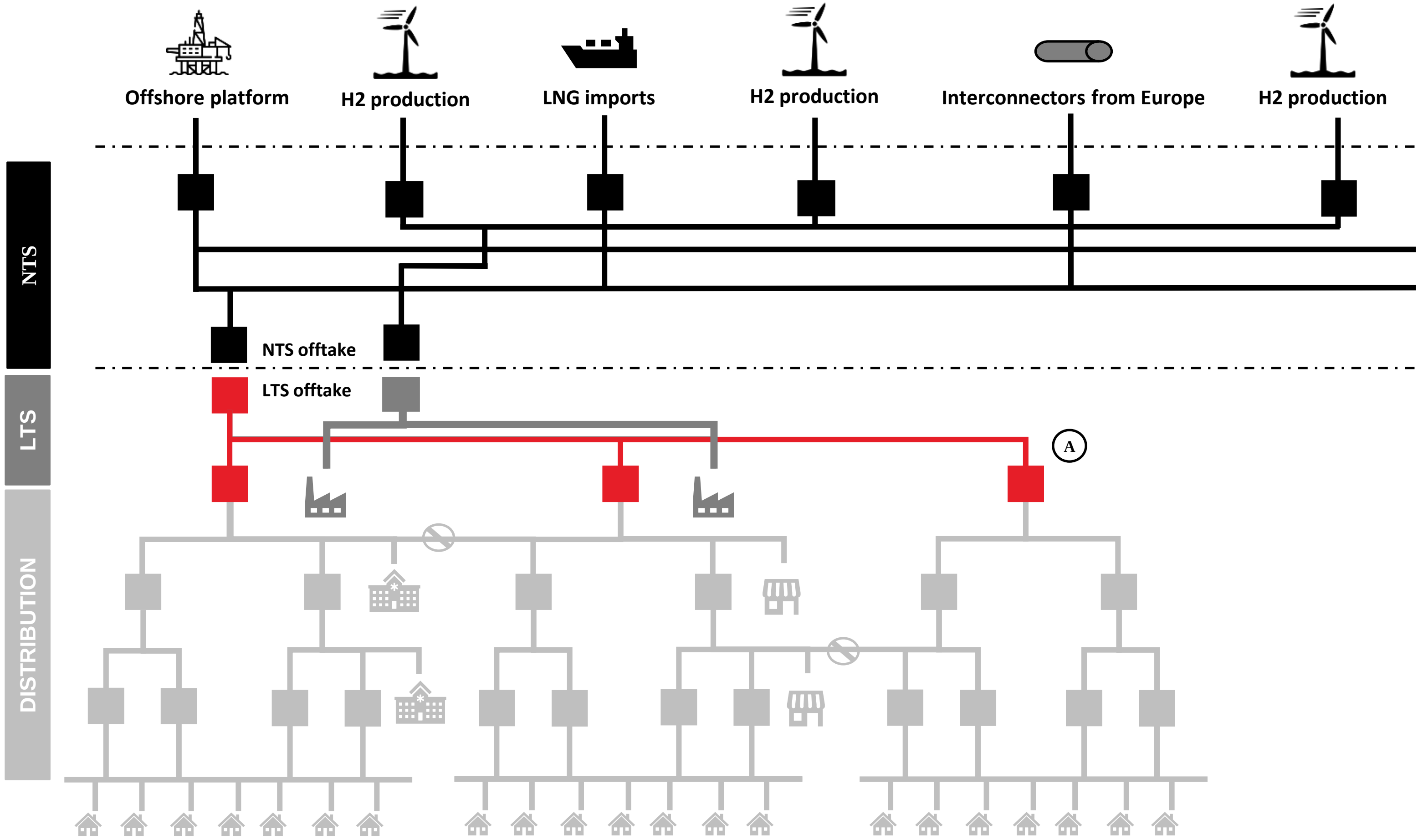
Figure 22. Domestic customer transition

Source: Arup analysis

ARUP

6.6 | Low Hydrogen Scenario

Step 5i. LTS Deenergising

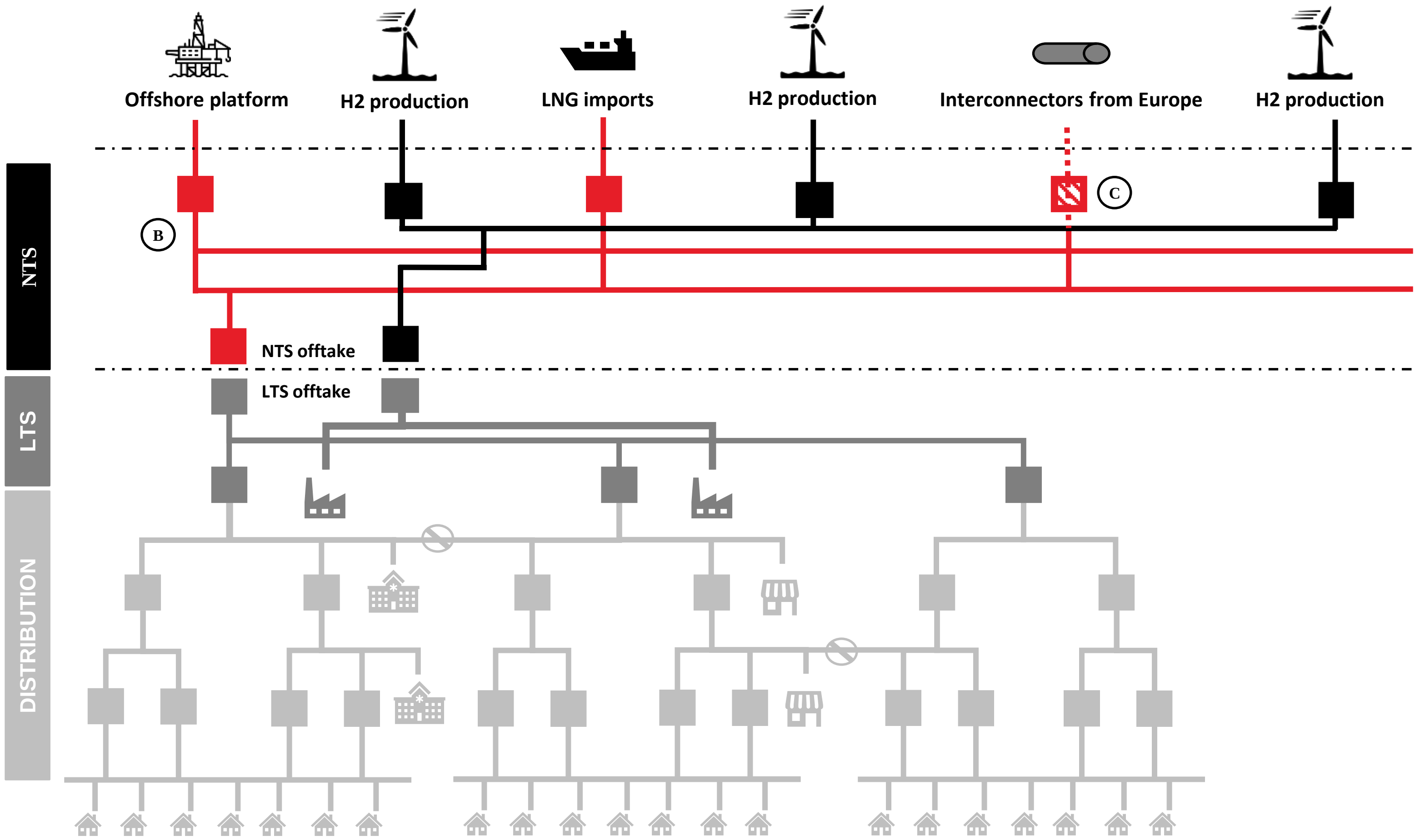


5a

With no more gas demand, the LTS can be deenergised and mothballed

6.6 | Low Hydrogen Scenario

Step 5ii. NTS Deenergising and repurposing



5b

With significantly reduced natural gas demand the NTS can be deenergised and mothballed.

5c

Where appropriate, a small percentage of the NTS is repurposed and integrated in the hydrogen backbone for security of supply.

ARUP

6.6 | Low Hydrogen Scenario

Repurposing (NTS and LTS) capex

Assumptions

As per the methodology, it is assumed that where practicable up to 20% of the remaining NTS is integrated into the new hydrogen system, primarily to act as additional storage:

- This is assumed a zero cost option i.e. only pipeline that is suitable will be repurposed.
- Additional compression is assumed to not be required given the lower volumes of hydrogen demanded.

No LTS is repurposed and integrated into the hydrogen backbone.

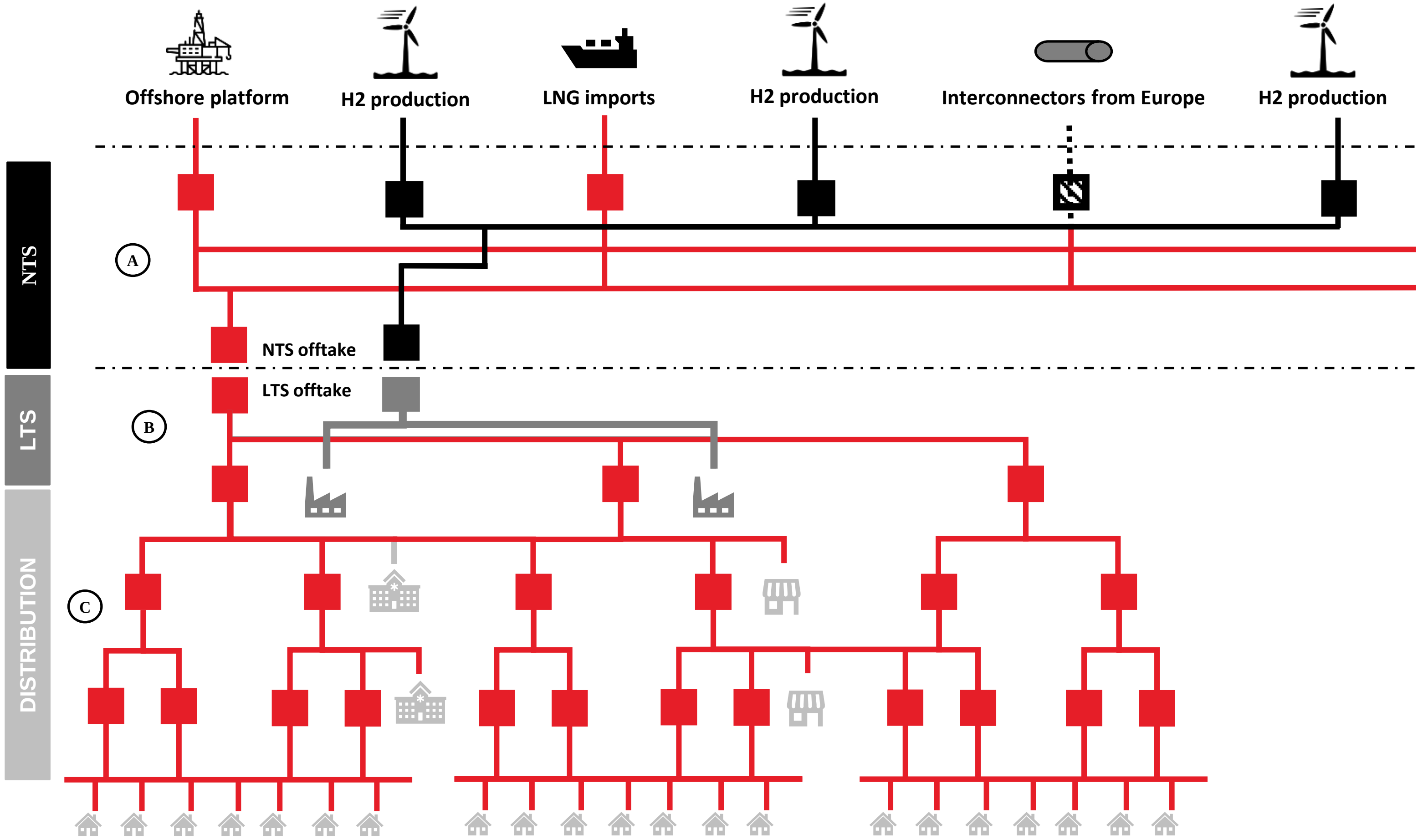
Note as per the scenario 20% of the NTS is retained for natural gas at zero cost

Timing

- Repurposing is assumed to be carried out as the domestic and industrial conversion frees up capacity on the natural gas system, from 2040 onwards.

6.6 | Low Hydrogen Scenario

Step 6. Network decommissioning



6a NTS decommissioning – due to material type, pipeline diameter likely to require a permanent solution e.g. grouting

6b LTS decommissioning – due to material type, pipeline diameter likely to require a permanent solution e.g. grouting

6c Distribution network decommissioning – PE elements of the network likely to be left in situ, however non-PE elements and the parts of the network that interface with other services likely to require a permanent solution e.g. grouting or removal.

6.6 | Low Hydrogen Scenario

Decommissioning capex

Assumptions

As per the scenario, parts of the NTS and LTS are no longer required for either hydrogen or residual natural gas:

- 60% of the NTS is decommissioned (where there is no regional hydrogen demand or residual natural gas demand)
- 100% of the LTS is decommissioned.
- Decommissioning unit cost is assumed at 50% of the weighted average MEAV cost for the NTS and LTS respectively.

Timing

- Decommissioning is assumed to be carried out as capacity is freed up on the system, from 2040 onwards.

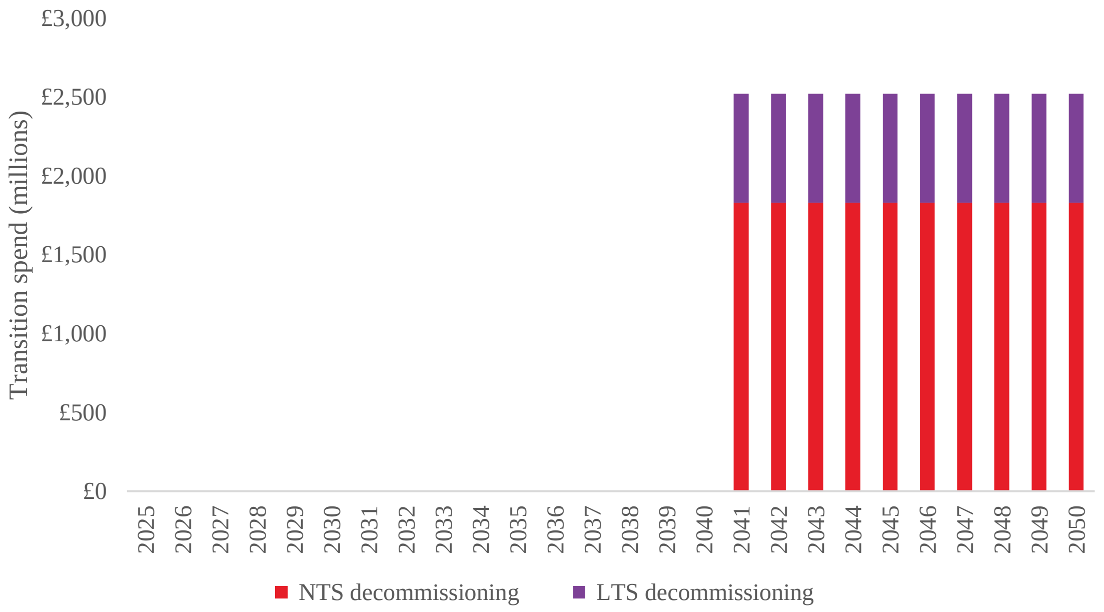


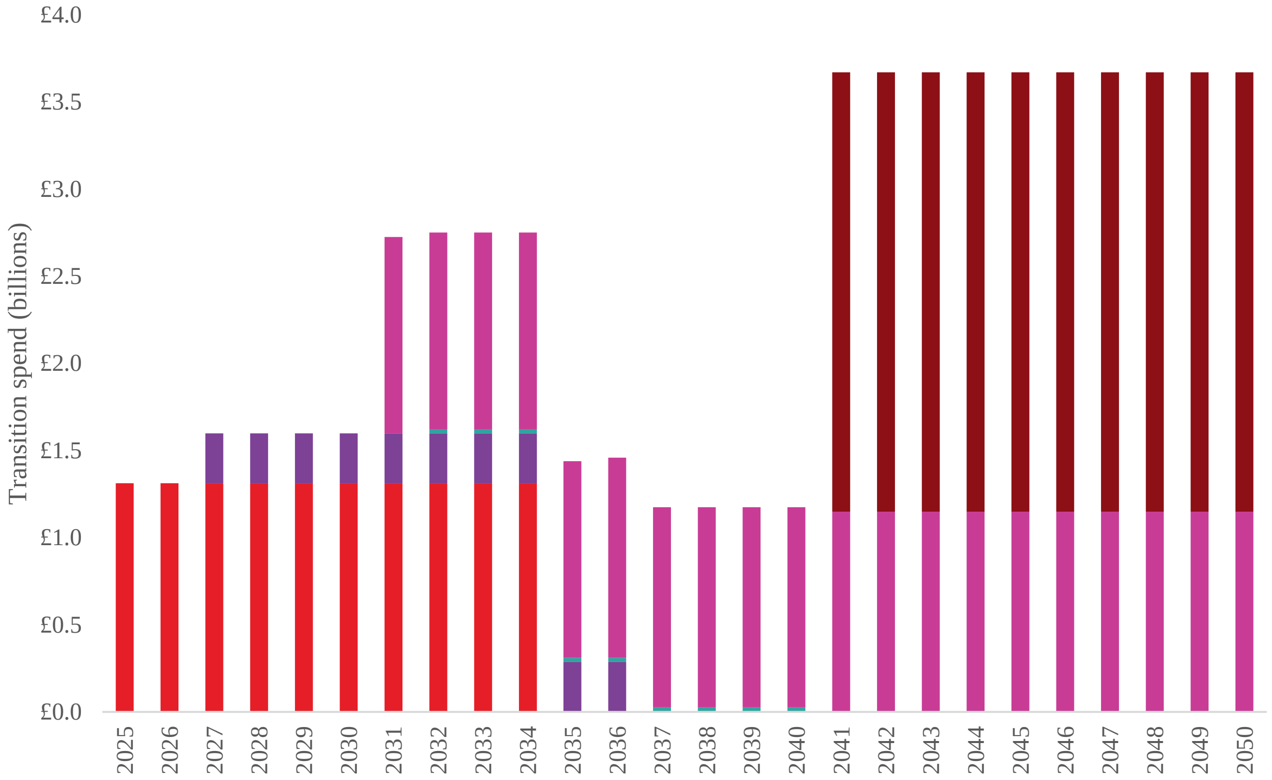
Figure 23. Decommissioning

Source: Arup analysis

6.6 | Low Hydrogen Scenario

Overall cost summary

Figure 24. Summary of annual spend by category



Source: Arup analysis

Figure 33. Summary of total capex spend by category (£m)

Hydrogen NTS backbone	£	13,119	19%
Hydrogen LTS backbone	£	2,852	4%
Distribution enabling works	£	-	0%
Industrial customer transition	£	224	<1%
Domestic customer transition	£	28,504	41%
Repurposing (NTS and LTS)	£	-	0%
Decommissioning	£	25,210	36%
TOTAL	**£**	**69,910**	**100%**

6.6 | Low Hydrogen Scenario

Summary of customer transition

The charts opposite present the domestic and minor Industrial and Commercial (I&C) customer transition (opposite, top) and the Major I&C customer transition (opposite, bottom) in the Low scenario:

- Major I&C customers are defined by the need for a non domestic governor less than 200scm/h, as identified in the Regulatory Reporting Packs. Such customers would likely include major industrial users of energy that are likely hard to abate e.g. glass manufacturing and would likely be connected higher up the pressure tiers of the distribution network.
- Domestic and Minor I&C customers include all other customers such as homes, small industrial and commercial units, shops, warehouses etc. and would likely be connected lower down the pressure tiers of the distribution network.
- Domestic and Minor I&C transition; of the existing c. 24m natural gas customers today, 100% switch to an alternative energy solution.
- Major I&C transition; of the existing c. 9,800 natural gas customers today, 60% transition to hydrogen, with the remining customers switching to alternative energy solutions.

Figure 25. Domestic customer & minor I&C transition

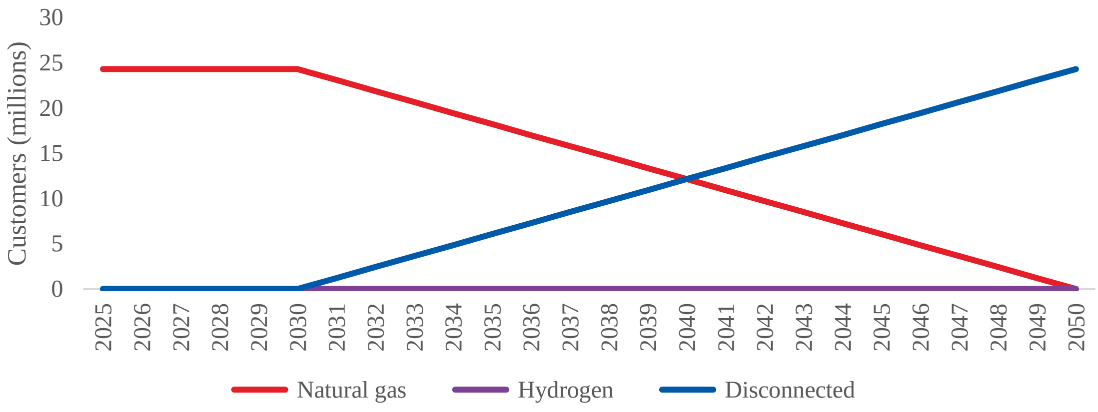
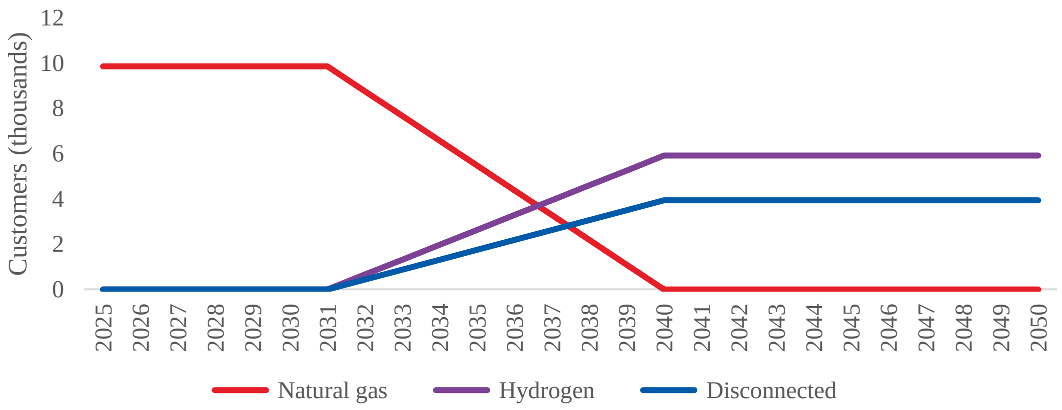


Figure 26. Industrial customer transition



Source: Arup analysis

7 | Summary, uncertainty, sensitivities and recommendations

7 | Summary, uncertainty and sensitivities

Overview

This section of the report provides a summary of the modelling results, uncertainty analysis and corresponding sensitivity analysis on a number of key drivers identified by the project team, and finally a discussion for further work and considerations deemed necessary as a result of the project findings.

Section navigation

- 7.1 Modelling summary; summary of modelling results and identification of key drivers and overall themes that separate the scenarios.
- 7.2 Uncertainty and materiality analysis; assessing each modelling step against a materiality and uncertainty matrix in order to identify themes for sensitivity analysis.
- 7.3 Sensitivity analysis; the project team have identified a number of sensitivities to run on the overall modelling to determine the impact of change across various unit cost and technical assumptions.
- 7.4 Phasing of works; identification of the critical path for the scenarios and the associated implications.

ARUP

7.1 | Modelling summary

Scenario comparison

Even though the high scenario requires the largest direct investment in new infrastructure. Note the cost of making the hydrogen, whilst likely to be significant, is excluded from this analysis.

Low and Balanced incur less direct investment in new infrastructure, but end up costing more than the High scenario as a result of NTS and LTS decommissioning costs, and the costs incurred for disconnecting customers from the gas system; this is evidenced in the increased spend at the tail end of the timelines.

The profile of spend across the scenarios largely reflects the overall trends seen in cost drivers:

- High requires more direct investment in infrastructure, thus incurring greater costs in the 2025-34 period associated with enabling the transition.
- Low and Balanced have lower costs earlier on in the forecast time period, as a result of less direct infrastructure investment, however the higher customer disconnection costs and decommissioning costs result in higher costs later in the modelling period.

A larger chart comparing the three transition scenario costs side by side is presented overleaf.

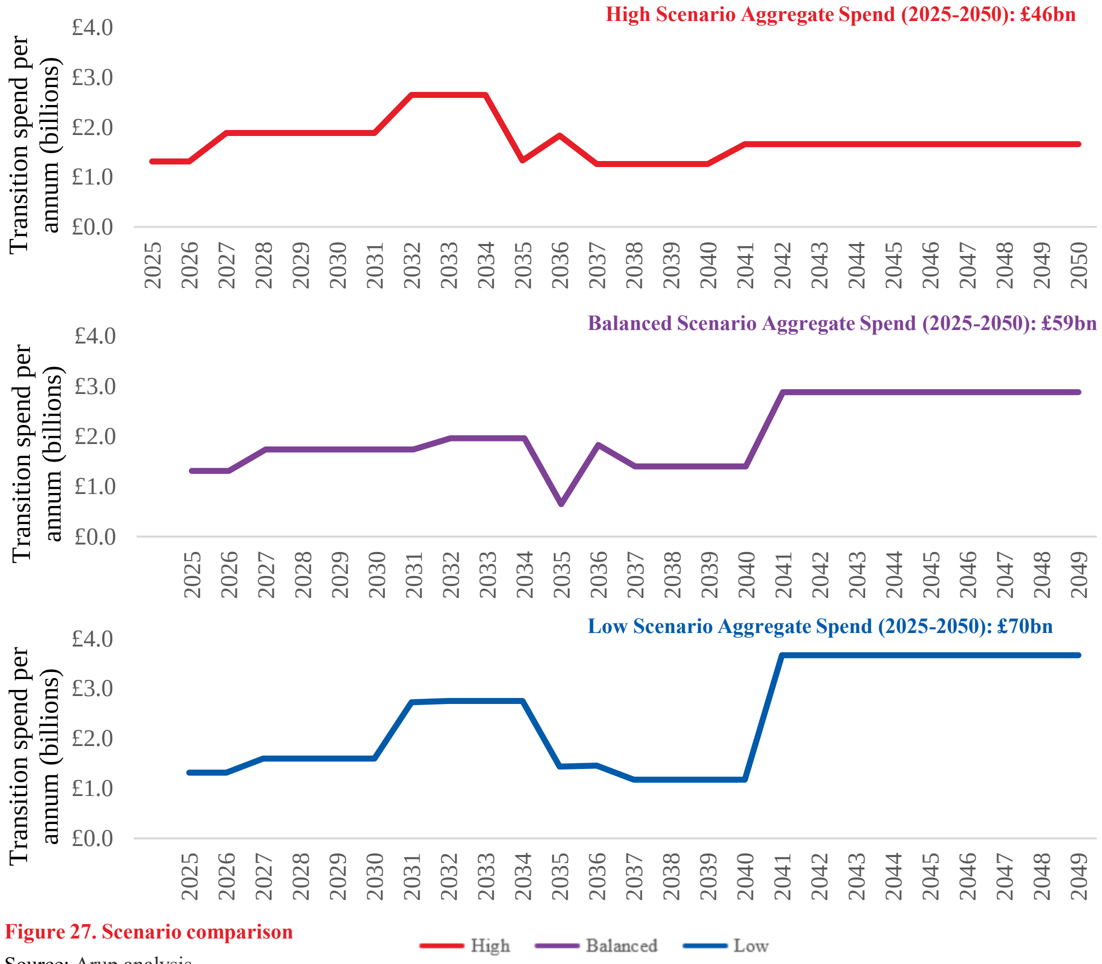
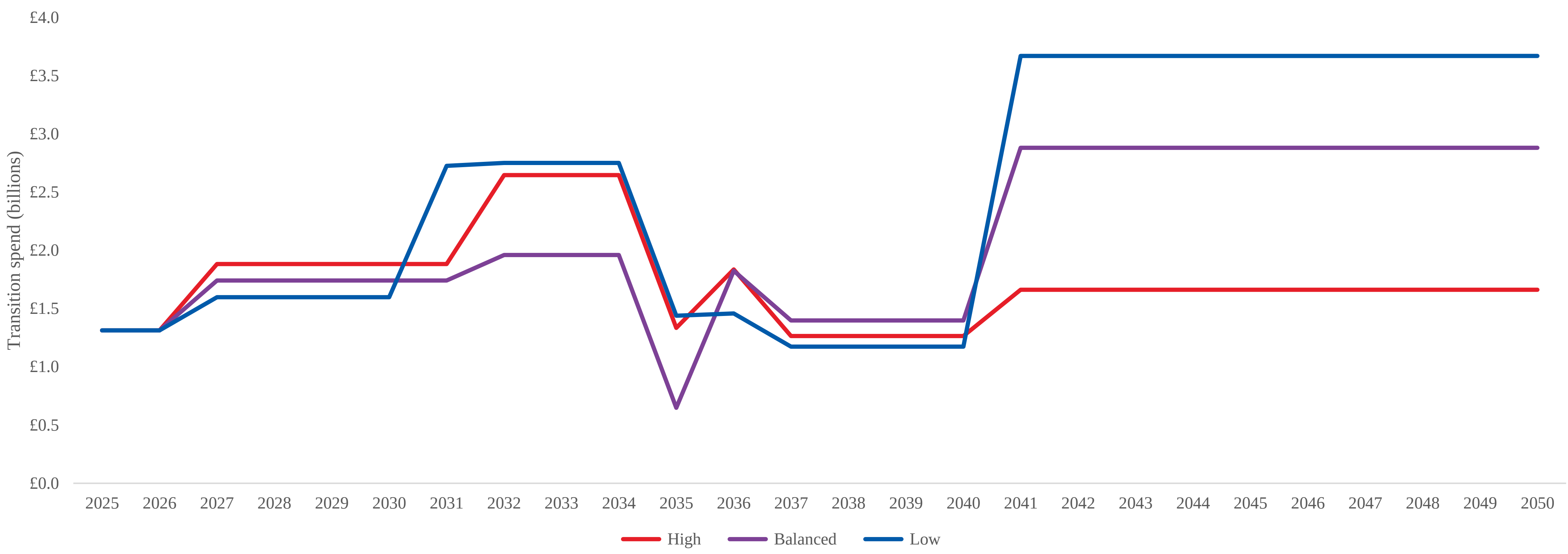


Figure 27. Scenario comparison

Source: Arup analysis

7.1 | Modelling summary

Figure 28. Scenario comparison – annual costs



Source: Arup analysis

ARUP

7.1 | Modelling summary

Identification of key cost drivers

The contributions of the different types of cost drivers within each scenario are shown in the charts opposite. The following observations and conclusions can be drawn:

- In the High scenario the cost allocation is largely driven by direct infrastructure investment including:
    - 80% of costs relate to direct investment in infrastructure: NTS and LTS hydrogen backbones, distribution network enabling works and repurposing the NTS and LTS.
    - The drivers behind this infrastructure investment have been tested by the stakeholder group, with unit costs developed in line with Ofgem's MEAV calculation.
    - 20% of cost is allocated to customer transition: 19% to domestic and 1% to industrial. Given the nature of these works, more than 50% of the domestic customer transition costs are driven by customers disconnecting from the gas network.

- Conversely, in the Balanced and Low scenarios customer transition spend is 37% and 41% respectively:
    - This is driven by the large scale domestic disconnection from the gas network in both scenarios. Whilst there is a 20% efficiency assumed on the unit rate, bringing the unit cost to £1,160 per customer gas disconnection, the number of customers disconnecting is very large (24m in Low).
    - If further cost efficiencies could be found, their impact would likely be material – even small changes in the unit cost have a significant impact.

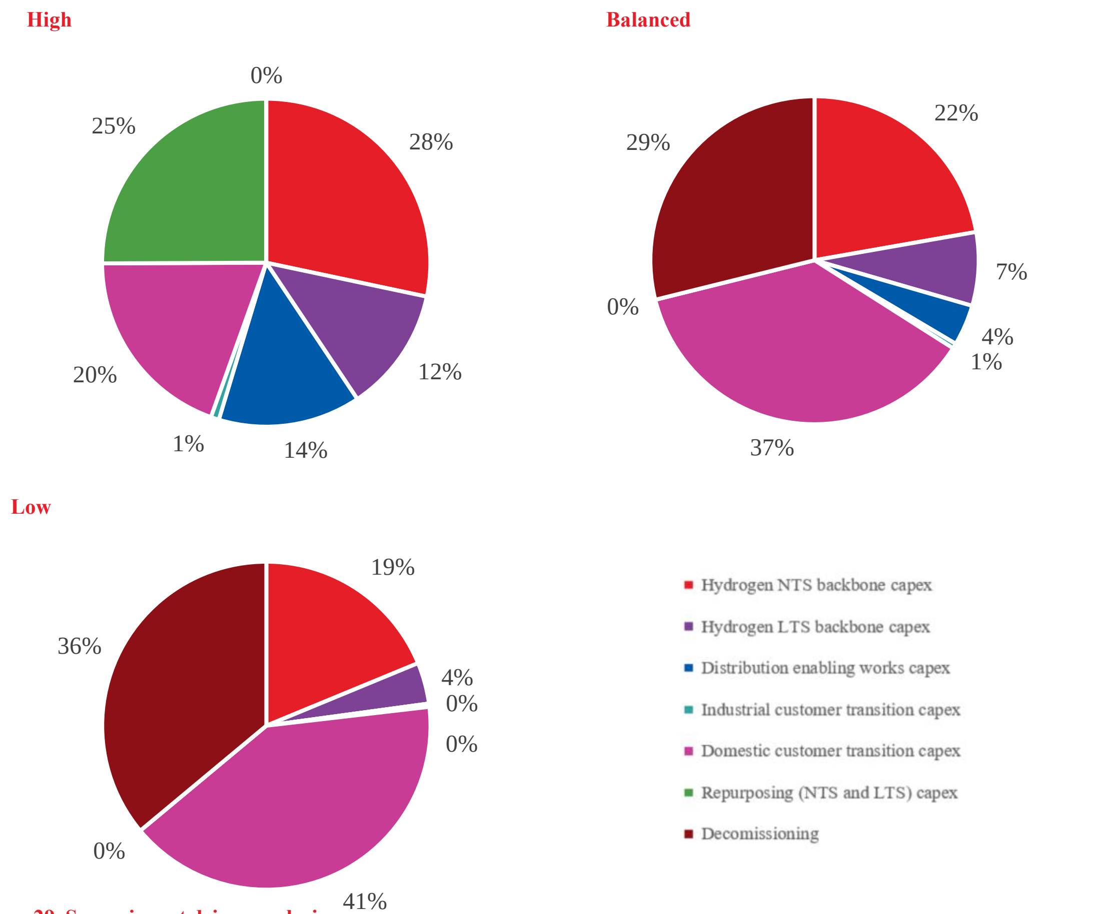


Figure 29. Scenario cost driver analysis

Source: Arup analysis

ARUP

7.1 | Modelling summary

Identification of key cost drivers cont'd

- Another key cost driver in the Balanced and Low scenarios relates to decommissioning at 29% and 36% of costs respectively:
    - As detailed in this report, there is very little formal guidance with regard to the decommissioning treatment of the network, as well as the likely costs of decommissioning infrastructure at this scale.
    - Relatively small changes to the assumptions could have a significant impact on the overall cost.
- The High scenario incurs 25% of its costs relating to NTS and LTS repurposing. As detailed in Section 4, the evidence base driving these costs is currently uncertain.
    - In the event an engineering solution can be found for hydrogen embrittlement, these costs could reduce significantly.

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7.2 | Uncertainty & materiality

Overview

Rationale

The modelling in section 6 estimates the capital costs of transitioning the gas based on the best information available to the project team today. However, some aspects of the costs and methodology may well change over time as more evidence is gathered and a better understanding of the process is developed. This means that there are significant levels of uncertainty attached to these cost estimates. The following section sets out an assessment of how uncertainty varies between different cost categories and across the scenarios. This helps to both contextualise the results in this report and provide an indication of where further work is needed to refine cost estimates and ensure work is delivered in the most efficient way possible.

What is being assessed

We will consider the key hydrogen uptake steps for the transition of the gas network and associated costs across high, balanced and low scenarios. As set out in the report, these steps include:

1. Hydrogen NTS Backbone
2. Hydrogen LTS Backbone
3. Distribution enabling works
4. Industrial customer transition
5. Domestic customer transition
6. Repurposing (NTS and LTS)
7. Decommissioning

Assessment criteria

We will assess each hydrogen uptake step against a ‘materiality’ and an ‘uncertainty’ methodology; these criteria are weighted equally.

The materiality criteria is defined by the total required spend of each hydrogen uptake step per scenario. A ‘high’ rating will be assigned to hydrogen uptake steps with a required spend of equal to or greater than £8 billion, a ‘medium’ rating will be assigned to hydrogen uptake steps with a required spend of between £1 billion and £8 billion and a ‘low’ rating will be assigned to steps with a required spend of less than £1 billion.

The uncertainty criteria is qualitatively defined considering two factors including 1) the level of certainty around unit cost of the applied methodology and 2) level of certainty on the technical transition methodology included the extent of stakeholder consensus. A ‘high’ rating will be assigned to steps where there is uncertainty across both of these factors, a ‘medium’ rating will be assigned to steps where there is uncertainty across one of these factors and a ‘low’ rating will be assigned to steps where there is high confidence in both of these factors.

7.2 | Uncertainty & materiality

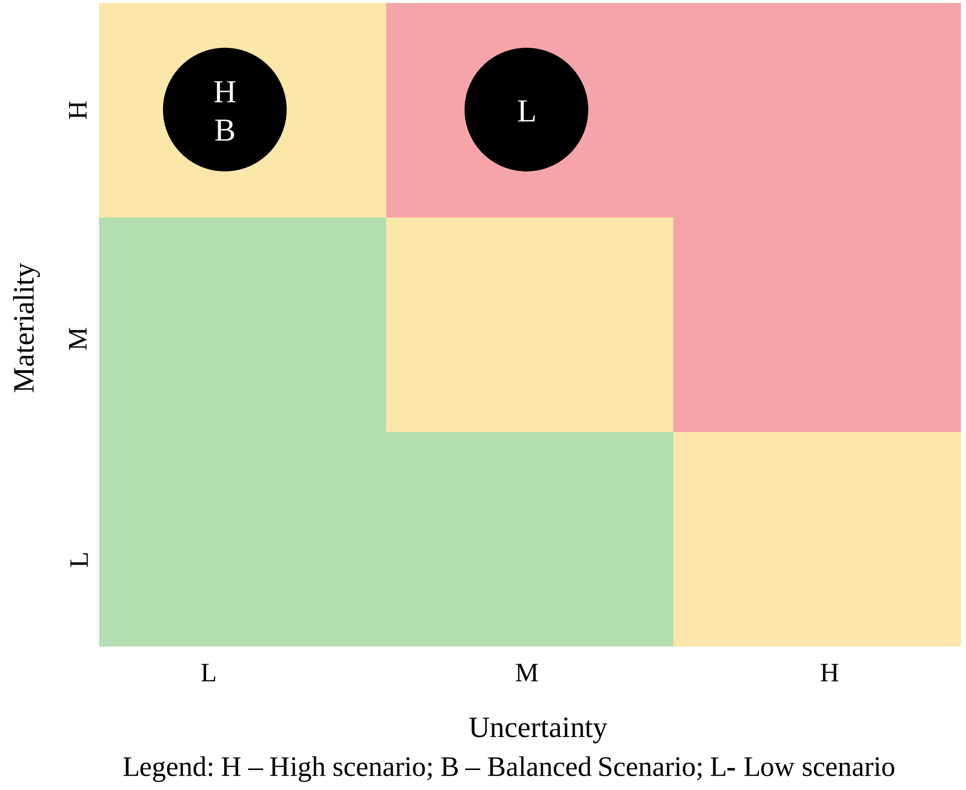
Hydrogen NTS Backbone

Summary of modelling assumptions:

As per the methodology, a hydrogen backbone equivalent to 20% of the existing NTS is required.

Materiality and Uncertainty Assessment:

Materiality	The total spend to develop an NTS hydrogen backbone across all scenarios is c. £13 billion, with £12 billion spent on new pipeline investments.	All scenarios **High**
Unit Cost	The unit costs used in the model for new pipeline and NTS injection point investments are from Ofgem's Modern Equivalent Asset Value (MEAV), which is the current reported replacement value of an asset. The unit cost used for new compressor stations have been derived from a recent National Gas Transmission (NGT) due diligence project. Sources of the unit costs are highly credible	All scenarios **Low**
Methodology	There was a consensus among all stakeholders Arup engaged with that an NTS hydrogen backbone is required to kickstart the transition and to service and connect all industrial clusters. Arup has assumed the NTS hydrogen backbone will be new build rather than repurposed as NGT confirm that the existing network does not have the capacity to repurpose any of the current network while maintaining security of supply for natural gas. Given the consensus among stakeholders, this step also scores 'low' for stakeholder methodology uncertainty in the High and Balanced scenarios. In the Low scenario there is more uncertainty with regard to the amount of backbone required; as a result, we have scored it a medium uncertainty for Low.	High / Balanced scenario: **Low** Low scenario; **Medium**



Hydrogen NTS Backbone – uncertainty & materiality assessment

Source: Arup analysis

7.2 | Uncertainty & materiality

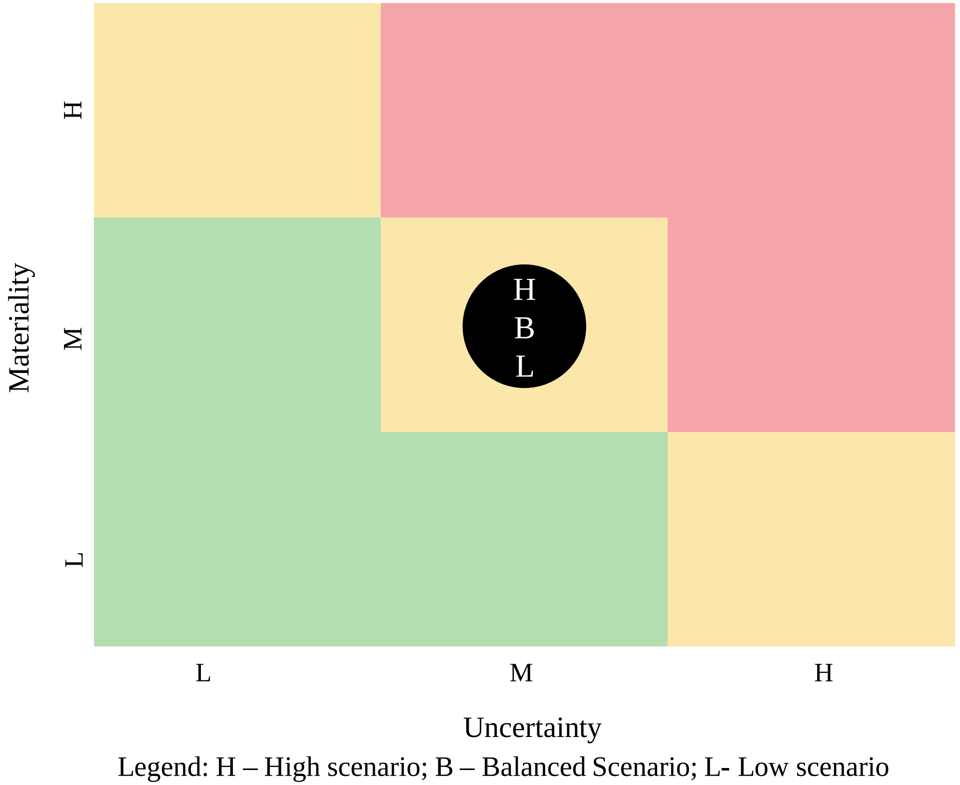
Hydrogen LTS Backbone

Summary of modelling assumptions:

As per the methodology, a hydrogen backbone of the existing LTS is required in order to transition industrial customers and enable the domestic transition at scale. The project team have assumed LTS backbone requirements of 40%, 30% and 20% of the length of the existing LTS for the high, balanced and low scenario respectively.

Materiality and Uncertainty Assessment:

Materiality	The total spend to develop a LTS hydrogen backbone varies across the scenarios. In the high scenario, the assumed required spend is £5.7 billion. In the balanced and low scenarios, the assumed required spend is £4.3 billion and £2.9 billion.	All scenarios **Medium**
Unit Cost	The unit costs used in the model for new pipeline, NTS offtakes and LTS gas entry points are from Ofgem's Modern Equivalent Asset Value (MEAV). Given the source of the unit costs is highly credible, this step for all scenarios scores 'low' for unit cost uncertainty.	All scenarios **Low**
Methodology	There was a consensus among all stakeholders Arup engaged with that a LTS hydrogen backbone is required to kickstart the transition and to service and connect all industrial clusters. The amount of LTS overbuild required per scenario is a modelling assumption, with medium uncertainty over the required length.	All scenarios **Medium**



Hydrogen LTS Backbone – uncertainty & materiality assessment

Source: Arup analysis

ARUP

7.2 | Uncertainty & materiality

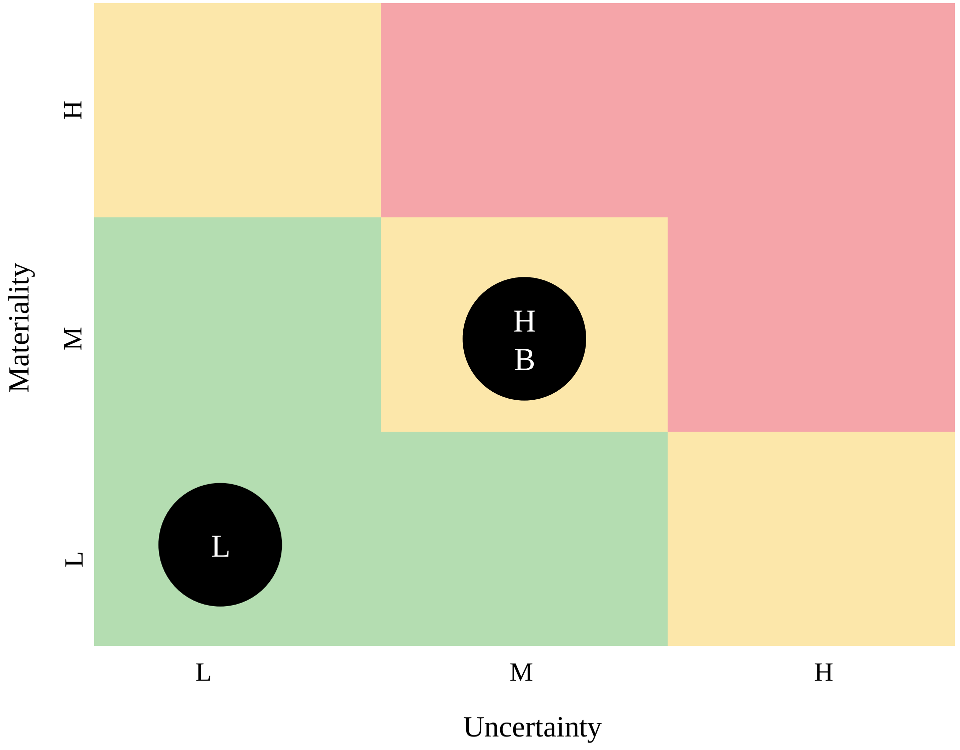
Distribution enabling work

Summary of modelling assumptions:

As per the methodology, domestic demand for hydrogen is expected to start in 2036 for both the high and balanced scenarios, requiring all the distribution networks to be made fully ready by 2040. We assume no distribution enabling works are required in the low scenario.

Materiality and Uncertainty Assessment:

Materiality	The total spend to undertake distribution enabling works varies across the scenarios. In the high and balanced scenarios, the assumed required spend is £6.5 billion and £1.6 billion.	High & Balanced scenario **Medium** Low scenario **Low**
Unit Cost	The unit costs used in the model for replacing non-PE mains and services as well as pressure reduction equipment are from Ofgem's Modern Equivalent Asset Value (MEAV). Source of the unit costs is highly credible	All scenarios **Low**
Methodology	There is good consensus among stakeholders that distribution enabling works will be required to accommodate the uptake of hydrogen in the high and balanced scenarios. It is the Health and Safety Executive's (HSE's) position that iron is not suitable for hydrogen, driving the non-PE mains replacement works. We note the gas networks are currently conducting experiments to provide an alternative view, with no current conclusions. OEMs of pressure reducing equipment have carried out high-level tests to date that indicate newer equipment is likely already hydrogen ready. However, there is some uncertainty around how this translates to the existing infrastructure and the associated safety case.	High & Balanced scenario **Medium** Low scenario **Low**



Legend: H – High scenario; B – Balanced Scenario; L- Low scenario

Distribution enabling work – uncertainty & materiality assessment

Source: Arup analysis

ARUP

7.2 | Uncertainty & materiality

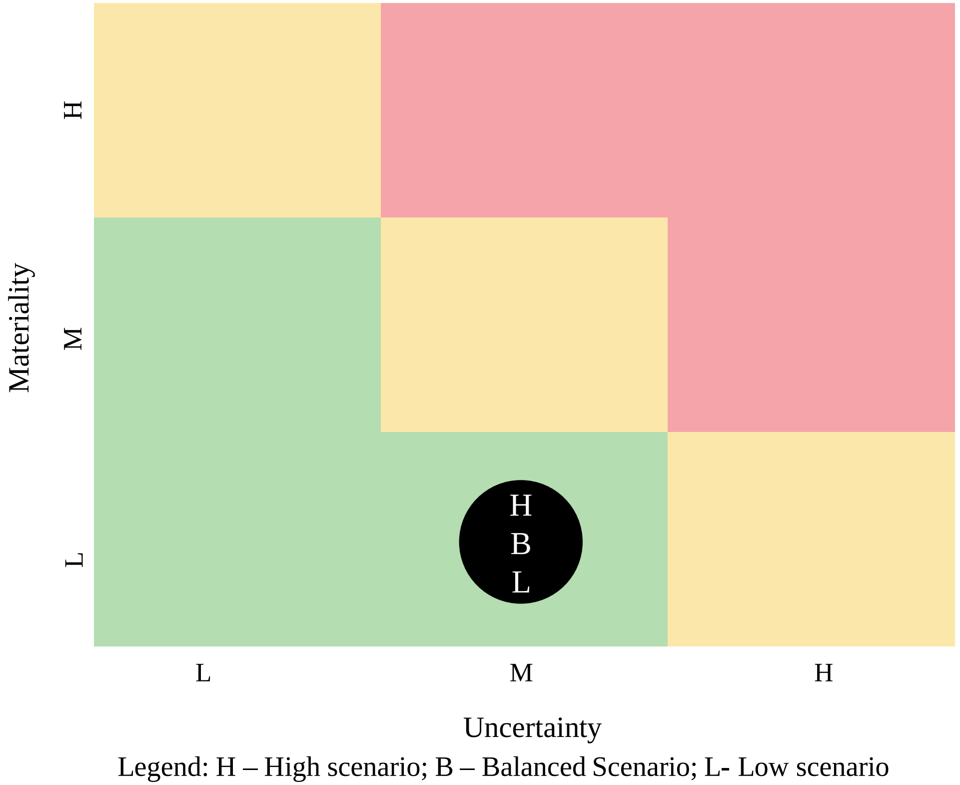
Industrial customer transition

Summary of modelling assumptions:

As per the methodology, industrial demand for hydrogen starts in the 2030s. Modelling assumptions vary per scenario, with 100%, 80% and 60% of the industrial customers transition to hydrogen in high, balanced and low scenarios respectively.

Materiality and Uncertainty Assessment:

Materiality	The total spend to enable industrial customer transition varies across the scenarios, driven by the number of converting customers; spend is £400 million, £300 million and £200 million in the high, balanced and low scenarios, respectively.	All scenarios **Low**
Unit Cost	The unit costs used in the model for modifying and replacing pressure reduction equipment are from Ofgem's Modern Equivalent Asset Value (MEAV). Source of the unit costs is highly credible	All scenarios **Low**
Methodology	OEMs of pressure reducing equipment have carried out high-level tests to date that indicate newer equipment is likely already hydrogen ready. However, there is some uncertainty around how this translates to the existing infrastructure and the associated safety case.	All scenarios **Medium**



Industrial customer transition – uncertainty & materiality assessment

Source: Arup analysis

7.2 | Uncertainty & materiality

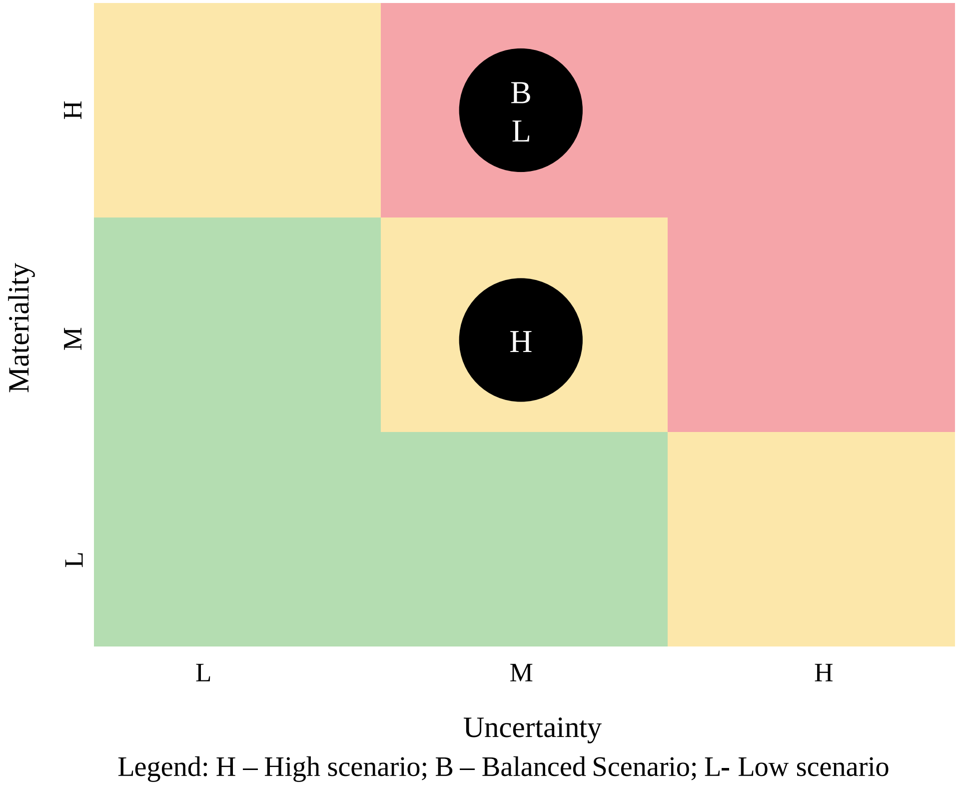
Domestic Customer transition

Summary of modelling assumptions:

Domestic customer transition modelling assumptions vary per scenario. In all scenarios, the distribution network has methane removed. In the high and balanced scenarios, varying amounts of network segments are reinjected with hydrogen, and in the low scenario, following the methane purge, the whole distribution layer is decommissioned (See later). Included to varying degrees under the scenarios in this modelling are customer disconnections from the gas network (i.e. being electrified) and customers transitioning to hydrogen.

Materiality and Uncertainty Assessment:

Materiality	The total spend to transition domestic customers off natural gas varies depending on the scenario. The assumed required spend for this step is £7.5 billion, £17.6 billion and £22.9 billion in the high, balanced and low scenarios, respectively driven by customer disconnection costs.	High scenario **Medium** Balanced & Low scenario **High**
Unit Cost	The unit costs used in the model for customer disconnection have been taken from publicly available reports quotations from the gas networks. However, we note there is a wide variance in the publicly available customer disconnection cost data. For ease, we have used a weighted average unit cost and applied a customer disconnection efficiency assumption to the figure. The network deenergising unit costs are estimated based on Arup's technical professional judgement.	All scenarios **Medium**
Methodology	The assumptions applied to customer disconnection and network deenergising methodology are based on current and well understood methods. However, we note the associated deliverability challenges as these works have not yet been deployed at the required scale of all three scenarios. Further, there could be alternative disconnection methodologies which could be investigated.	All scenarios **Medium**



Domestic customer transition – uncertainty & materiality assessment

Source: Arup analysis

ARUP

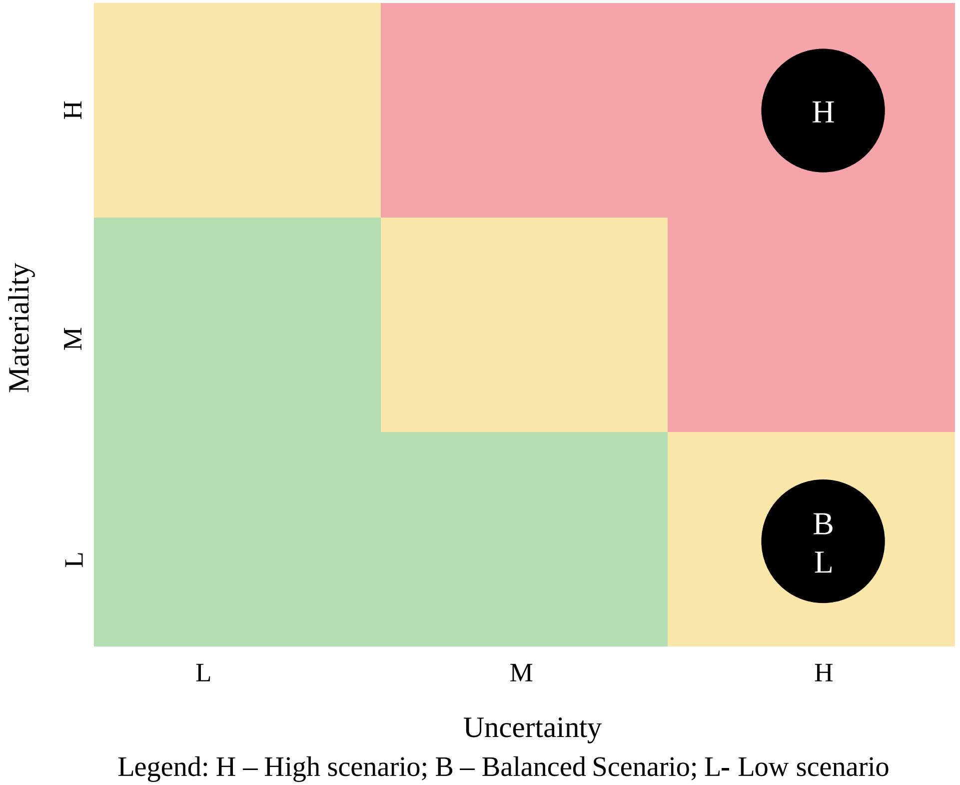
7.2 | Uncertainty & materiality

Repurposing (NTS and LTS)

Summary of modelling assumptions:

As per the methodology, there are repurposing works for the NTS and LTS across all scenarios. In the high scenario, the NTS and LTS are repurposed as soon as practicably possible. In the balanced and low scenarios, it is assumed that a percentage of the remaining NTS and LTS are integrated into the new hydrogen system to primarily act as additional storage.

Materiality	The total spend to repurpose the NTS and LTS varies depending on the scenario. For the balanced and low scenario, it is assumed no spend is required resulting in a materiality assessment score of low. For the high scenario, the total required spend is £11.6 billion, driven by NTS replacement and required new compressor stations and units.	High scenario **High** Balanced & Low scenario **Low**
Unit Cost	The unit costs used in the model for replacing NTS and LTS are from Ofgem's Modern Equivalent Asset Value (MEAV). Conversion costs are assumed to be a percentage of the MEAV costs.	All scenarios **Medium**
Methodology	The assumed suitability of the NTS and LTS for hydrogen (where there are no metallurgy or condition issues) is currently based on preliminary findings from the gas networks. The assumptions also simplify the location impact of non-compliant materials.	All scenarios **High**



Repurposing (NTS and LTS) – uncertainty & materiality assessment

Source: Arup analysis

ARUP

7.2 | Uncertainty & materiality

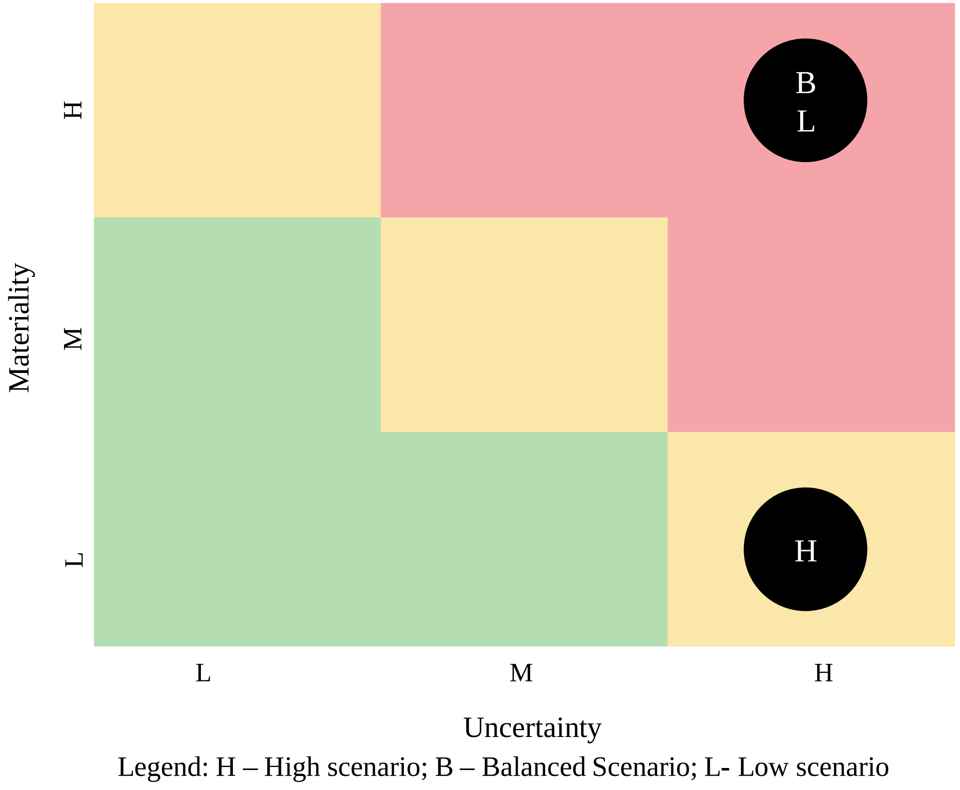
Decommissioning

Summary of modelling assumptions:

As per the methodology, no decommissioning of the NTS and LTS is forecast in the high scenario. In the balanced and low scenarios, parts of the NTS and LTS are no longer required for either hydrogen or residual natural gas. Decommissioning is assumed to be carried out as capacity is freed up on the system from 2040 onwards.

Materiality and Uncertainty Assessment:

Materiality	The total spend to decommission the NTS and LTS varies across the three scenarios. As no decommissioning is forecast in the high scenario, no cost is associated to this step, resulting in a 'low' materiality assessment score. The assumed required spend is £17 billion and £25.2 billion in the balanced and low scenarios, respectively. This results in a 'high' materiality assessment score for this step in both the balanced and low scenarios.	High scenario **Low** Balanced & Low **High**
Unit Cost	The unit costs used in the model for the decommissioning of the NTS and LTS is a percentage of new build NTS and LTS costs from Ofgem's Modern Equivalent Asset Value (MEAV).	All scenarios **Medium**
Methodology	There is limited consensus among stakeholders about how decommissioning of the NTS and LTS at the scale seen in the balanced and low scenario would take place. Additionally, there is the potential need for decommissioning in the low pressure distribution network. Given this, this step for all relevant scenarios scores 'high' for stakeholder methodology uncertainty.	All scenarios **High**



Decommissioning – uncertainty & materiality assessment

Source: Arup analysis

ARUP

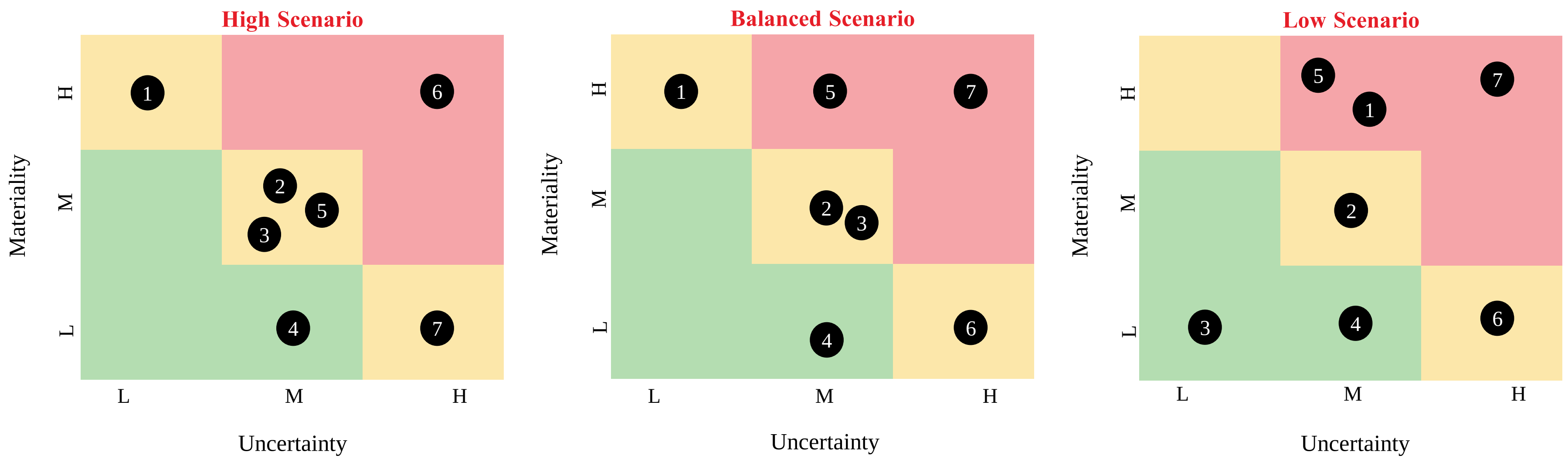
7.2 | Uncertainty & materiality

Summary

As the diagrams below show, there is high uncertainty across both the materiality and uncertainty criteria for all three scenarios, particularly for the following steps: domestic customer transition, repurposing (NTS and LTS) and decommissioning. We note, work is currently being progressed on repurposing the NTS via Project Union. Nonetheless, these steps should be focus areas for further study to reduce this uncertainty.

Legend

1. Hydrogen NTS Backbone
2. Hydrogen LTS Backbone
3. Distribution enabling works
4. Industrial customer transition
5. Domestic customer transition
6. Repurposing (NTS and LTS)
7. Decommissioning



Summary – uncertainty & materiality assessment

Source: Arup analysis

7.3 | Sensitivities

Introduction

The Uncertainty & Materiality analysis demonstrated the degree of uncertainty in the various elements of the transition methodology, as well as their materiality to the overall cost estimate. In particular two elements stand out as amongst the most uncertain and the most material (particularly in Balanced and Low):

- Domestic customer transition
- Decommissioning

In order to contextualise the uncertainty in each of these elements, the project Team have developed sensitivities. These sensitivities are largely qualitative, and rather than applying percentage uplifts to unit costs or volume, Arup have instead focussed on how the methodology could change in the future.

For the purposes of demonstrating the impact of the change in methodology and resulting cost estimate, a high-level quantitative sensitivity is provided to summarise.

ARUP

7.3 | Sensitivities

Domestic customer transition

Modelling overview

The chart opposite (top) presents a breakdown of the cost estimate against each of the scenarios.

Customer disconnection is the key driver of cost across all scenarios:

- These costs are associated with the removal of the gas network's equipment from within the customer premises, as well as the 'making safe' of the gas service connection
- Note as per the scope of this project, and the current ownership boundary of the networks, the customer's internal system including boiler, appliances are not considered as part of this estimation

Currently all networks provide public quotations for carrying out this activity, which have been used for the purposes of his assessment; the weighted average price being £1,450 per customer. Note this unit cost is understood to capture the variation in customer premises (e.g. urban vs rural, Multiple Occupancy Buildings (MOBs) etc.). The corresponding scope for this is understood to be:

- Removal of meter if agreed with the energy supplier (internal or external to the customer premise)
- Removal of meter box (if applicable)
- Remediation of customer premise e.g. patching of holes in the wall
- Capping of the customer service below ground at the ECV
- Capping of the service pipe below ground at the junction to the gas main

Figure 30. Breakdown of customer disconnection costs in the Basecase

Source: Arup analysis

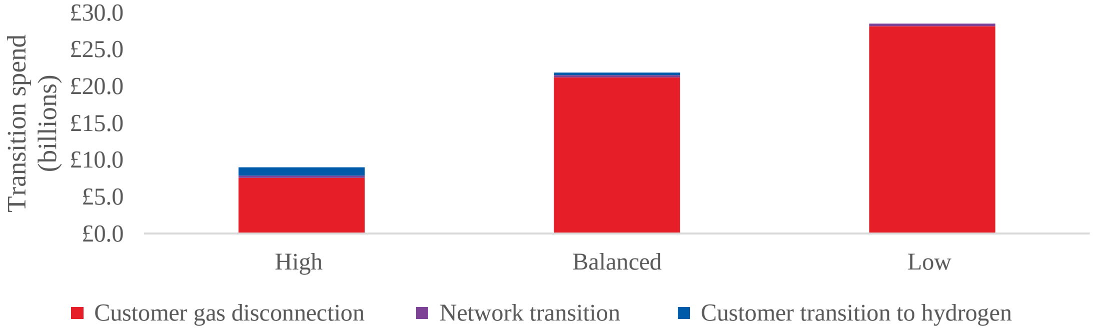
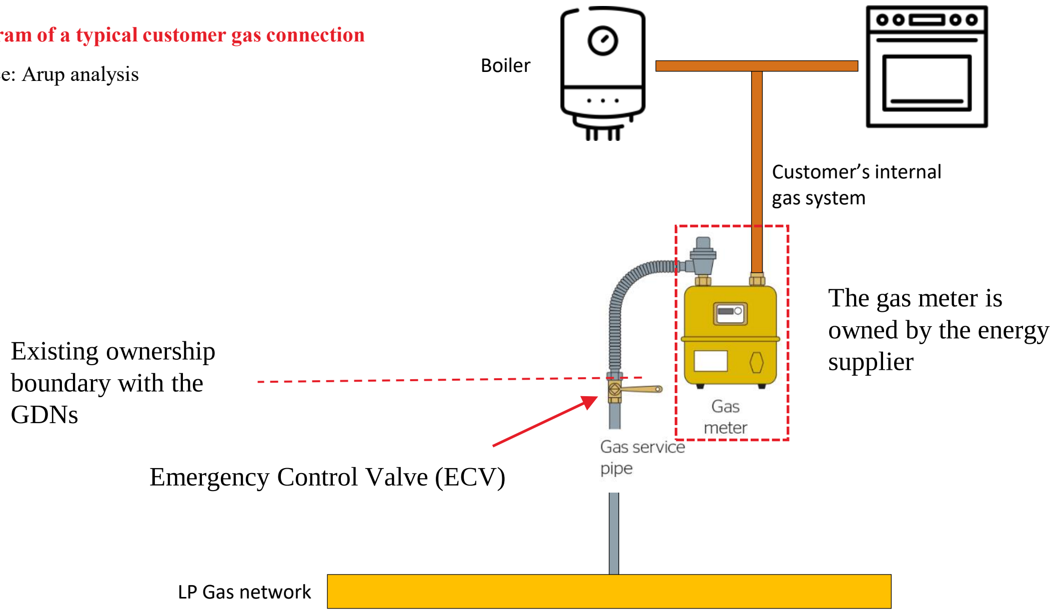


Diagram of a typical customer gas connection

Source: Arup analysis



7.3 | Sensitivities

Domestic customer transition cont'd

As summarised in the uncertainty & materiality section, there is considerable unit cost uncertainty given the spread of quotations from across the various networks, and there is also methodology uncertainty if such an activity was required at scale (in Balanced and Low):

Unit cost

- Arup understand these costs are not a licensed activity and are not subject to any form of scrutiny. It is considered likely that there is variance of scope, delivery methodology and unit costs associated with the quoted rates.
- If a common approach was adopted under a licensed activity, it is reasonable to assume the quoted range would likely decrease and average cost per customer would likely reduce by a small margin (c. 10%).

Methodology

- The unit cost considers a single intervention, rather than a program of interventions as required in the Balanced and Low scenarios. The Team consider significant savings could be achieved by disconnecting all the houses on a street at once, rather than one at a time.
- The scope of the intervention, particularly the capping of the service considers there is still a live gas network; in Balanced and Low where the network is being decommissioned, the Team consider it may be possible to remove the need to cap the service at both ends. Given this step of the process adds considerable time and cost to the process (typically gas mains run down the road, are 6ft deep and would require a permit to excavate the road), the Team consider significant savings could be achieved if the need to do this was removed.
- Delivery of these works; the Team consider it may be more cost effective to have this work carried out by a specialist entity with an optimised cost structure and appropriately trained employees, rather than carried out by the networks.

Sensitivity

Arup's approach to this sensitivity is to pose the following question: 'what would we have to believe to have a material impact on the modelling methodology and unit cost?':

- Government would mandate the future energy solution, removing customer choice and the associated legislation around the customer's legal right to a gas connection. As a result, gas customers would be forcibly disconnected from the network, according to the schedule of the National transition.
  - Note this is a fundamental piece of legislation with considerable social implications, particularly for customers who haven't been able to transition to an alternative energy solution in time.
- Customer transition is mandated, under a strict timeframe i.e. customers are given a strict timeframe under which an alternative energy solution would need to be installed.
  - This timeframe would ideally be over 12 months, due to the existing safety regulations governing customers being isolated from gas at just the ECV (see more below).
  - It is considered likely that some sort of financing package would have to be created for customers, in a similar way to the Town's Gas conversion (i.e. financing for customer's heat pumps, appliances, new central heating systems etc.).
- Gas safety regulations would require amendments on 2 fronts:
  - Currently the networks are required to permanently disconnect a customer from the network within 12 months of them coming off gas. This is achieved by capping the service below-ground outside the customer premises; this drives the above timeframes. In order to ease the pressure of transition, careful consideration should be given to the safety case around extending this 12-month timeframe.
  - Currently there is a requirement to cap the service at the main, if the pipe is permanently no longer in use. In the event that the gas networks have been decommissioned and are no longer live, consideration should be given to the safety / environmental / legal implications of removing the necessity of these works, at considerable cost savings.

7.3 | Sensitivities

Domestic customer transition cont'd

Sensitivity cont'd

- If the legal ownership boundary between what equipment is the network's responsibility, what is the energy suppliers and what is the customers, is simplified it is possible that a single entity could undertake a single intervention at a customer premises to carry out the retrofit of an alternative heating system, the removal and disposal of the legacy gas system, and the capping of the service pipe.
  - Consideration should be given to the costs associated with waste disposal of the legacy gas equipment. Pipes will have scrap value and could easily be recycled; newer meters will have a mix of electronic and metallic components which will likely be more difficult to dispose of and will likely incur additional costs.
- If the customer transition is carried out as part of a well-coordinated national programme, likely by a specialist delivery vehicle, with a defined set of licensed activities.
  - Such an entity would have to employ and upskill a large labour force for the duration of the transition.
  - Given the highly skilled, safety critical nature of the works, significant training costs are expected.
  - Additionally given the pre-defined length of employment (i.e. 15 years maximum), it is expected staff would require salaries at a premium compared to today.

Sensitivity calculation methodology

If all the above were true, Arup consider the cost per customer could be significantly lower, due to the consolidation of work to a single party, with a reduced scope.

The unit cost would account for:

- Capping of the service, below ground, outside the customer premises
- Removal of the meter, ECV etc. and remediation of the customer premises
- Recycling and disposal of residual waste
- Associated overheads for the specialist organisation
- Adjusted salaries for staff

For the purposes of this sensitivity, Arup propose to use a unit cost of £500 per customer. Note this is a high-level estimate and would require significant follow up work to determine the veracity of this unit rate. Note whilst £500 is significantly lower than the weighted average costs currently quoted by networks, it is not significantly lower than the lowest cost in the range.

Arup consider this unit rate, whilst high-level and highly uncertain, will illustrate the purpose of the sensitivity; to demonstrate the impact of material changes in methodology on the overall Scenario cost estimate. The impact of this change on the Scenarios is illustrated overleaf.

Note given this Sensitivity is only anticipated to affect the Balanced and Low scenarios, where systematic customer transition is forecast.

In the High scenario, whilst some customers do transition away from gas, it is envisaged this transition is sporadic and therefore unable to lever the majority of efficiencies described in the sensitivity, with the exception of customer disconnections becoming a licensed activity; this is anticipated to reduce the unit costs by up to 10%.

7.3 | Sensitivities

Domestic customer transition cont'd

	Scenario	Basecase (£)	Sensitivity (£)	% Change
Unit cost	High	1,450	1,305	10%
	Balanced	1,160	500	57%
	Low	1,160	500	57%
Customer disconnection costs	High	7.6bn	6.8bn	10%
	Balanced	21.2bn	9.1bn	57%
	Low	28.1bn	12.1bn	57%
Total scenario cost	High	46.3bn	45.5bn	2%
	Balanced	59.0bn	46.9bn	20%
	Low	69.9bn	53.8bn	23%

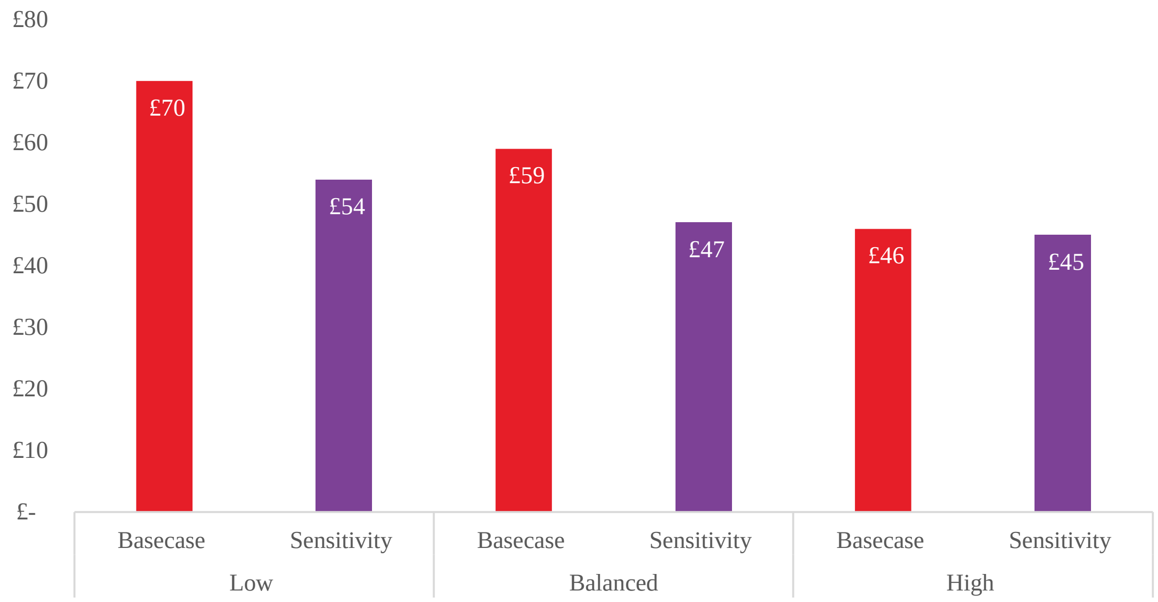


Figure 31. Domestic customer transition sensitivities across all scenarios

Source: Arup analysis

7.3 | Sensitivities

Decommissioning

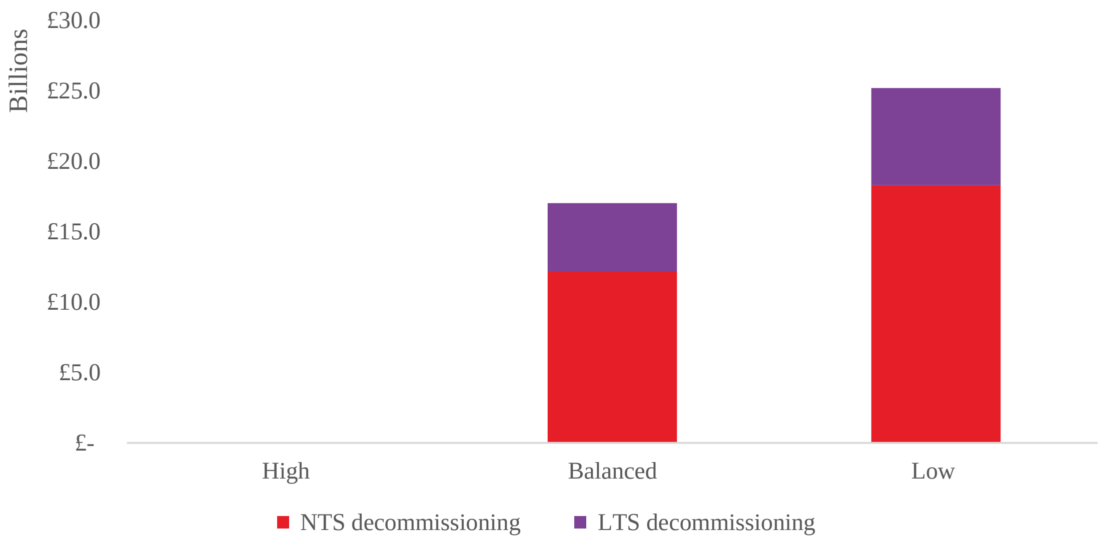
Modelling overview

The chart opposite (top) presents a breakdown of the Basecase cost estimate against each of the scenarios.

- As per the Scenario, decommissioning is not envisaged in High.
- Balanced and Low incur significant decommissioning costs;
    - NTS decommissioning costs contribute the majority of cost under both scenarios, driven by the higher unit cost per km, despite fewer km of network being decommissioned.
    - This difference in unit cot is reflected in the Ofgem MEAV costs; NTS is typically a larger diameter pipe, built in predominantly remote areas (driven by safety considerations). Construction activities are typically hampered by significant access and logistics costs.
- The Basecase assumptions consider that 100% of the inactive NTS and LTS is decommissioned. Decommissioning treatment can vary, according to the associated safety, environmental and legal risks associated with the asset.
- The Basecase assumes that the NTS and LTS are grouted, in line with the treatment of discrete sub-surface pipeline sections that have previously been decommissioned:
    - Grouting removes the risk of pipeline collapse and subsidence (safety risk mitigation)
    - Grouting prevents the ingress and transmission of groundwater (environmental risk mitigation)
    - The mitigation of these risks also mitigates the potential for associated future liabilities; often the primary driver for a permanent decommissioning solution.

Figure 32. Breakdown of decommissioning costs in the Basecase

Source: Arup analysis



7.3 | Sensitivities

Decommissioning

As detailed in the Report (Section 4.4), and highlighted in the uncertainty & materiality analysis, Decommissioning represents a high uncertainty, high-materiality line item in both the Balanced and Low scenarios.

The fundamental source of the uncertainty is the decommissioning methodology; at present there is no system-wide guidance. This methodology drives the type and volume of decommissioning works.

Unit cost

- Unit cost uncertainty is driven by a general lack of prior work in this space at a system level, from which to extrapolate, however there are multiple examples from discrete projects.
- Given that materials typically make up less than 50% of build cost, and that much of the same access, logistics and civils issues are still relevant in the event of decommissioning, Arup and the Stakeholder group consider the basecase unit costs to remain a reasonable estimate for grouting works.

Methodology

- Currently it is assumed that all the metallic, large diameter pipe in the NTS and LTS is decommissioned, on the grounds of safety risk (pipe collapse and resulting subsidence), environmental risk (pipe acting as a vector for groundwater) and legal risk (the resulting legal liability is considered unpalatable).
- Note large diameter metallic pipe in the distribution network is not included in the current assessment. Stakeholder groups assert this would require consideration in the sensitivity.
- Arup expect more consideration is given to system wide decommissioning, that takes a risk base approach to maximising risk reduction whilst minimising the financial impact of doing so. This approach is considered similar to the current guidance in the offshore oil and gas industry [30].

Sensitivity

Arup's approach to this sensitivity is to pose the following question: 'what would we have to believe to have a material impact on the modelling methodology and unit cost?':

- Government produce industry guidance for the decommissioning of gas transmission and distribution infrastructure, as per the current guidance issued for the offshore oil and gas industry. This guidance would likely create a pragmatic, risk based solution to decommissioning.
- The main differences between offshore and onshore considerations are inherent risks posed:
  - Offshore there is limited safety risk posed by a buried pipeline, whereas onshore there is a much greater risk from road or building collapse to a farmers vehicle falling into the cavity.
  - Similarly, the onshore environmental risks including the pipelines acting as a vector for groundwater or surface run off are different to offshore. With water quality becoming a key issue for the water industry, Arup consider the environmental considerations for decommissioning to become more significant in future, driving more permanent / onerous decommissioning treatment.
- The creation of a specialist entity that would carry the ongoing obligation to monitor the status of the decommissioned assets that have been left in situ, and own the liability associated with any residual infrastructure. Such an entity would be comparable to the Coal Board.
- Networks likely remunerated for the remaining asset value in the infrastructure (that they have invested in on the basis that the regulatory model will compensate them over the lifetime of the asset).
  - Note the current combined RAV of the networks is c. £26bn [31], however this would likely decline in the Balanced and Low scenarios as the existing asset base ages, and new capex is kept to a minimum.
  - The remuneration of the this is not considered in Arup's calculations, but should be noted as part of wider transition costs.

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7.3 | Sensitivities

Decommissioning cont'd

Sensitivity calculation methodology

If all the above were true, Arup consider the following decommissioning methodology could be adopted, in line with a more pragmatic, risk based approach:

- Using a risk based methodology 20% of the NTS and LTS would still likely require a permanent decommissioning solution (grouting) at a unit rate of 50% of the MEAV.
- The remaining 20% would be left in situ and monitored for any increase in Safety risk. Environmental risk would be mitigated by sectioning and capping the pipeline at appropriate intervals, thereby preventing the transmission of ground / surface waters. A unit rate of 10% of the MEAV is proposed as an indicative cost.
- In the distribution layer, where the majority of the network is PE (that does not degrade over time), the main safety risk is limited to metallic pipes. For the purposes of this exercise Arup have assumed any metallic pipe with a diameter of 12” and above would require grouting, in order to mitigate subsidence and associated safety risk. A unit rate of 50% of the MEAV is proposed, in line with the NTS and LS modelling.
- The remaining distribution network would be left in situ and monitored. As per the NTS and LTS, this network would also require sectioning and capping, at a unit rate of 10% of MEAV, in order to mitigate any environmental risks.
- The liability associated with the residual assets would be transferred to a new entity and the networks remunerated for the residual asset value. Note the associated costs for ongoing monitoring, legal obligations etc have not been calculated as part of this exercise.

Note for the purposes of this exercise (a high-level cost estimate for activities relating to gas networks across a range of scenarios), decommissioning activities have been incurred within the project timelines (i.e. prior to 2050). Pragmatically, Arup consider the permanent decommissioning of the networks to be a last resort option, typically carried out when all other options have been exhausted e.g. re-use, many years after the network has been deenergised.

Arup would expect that once the network has been deenergised, it would remain as a mothballed asset under the existing Pipeline Integrity Management System (PIMS), at a relatively small cost. This would preserve the integrity of the assets whilst possible re-use options were explored.

Note Arup understand that there may be significant legal challenges associated with the re-use of this network for any other purposes other than as part of a gas system, relating to the conditions of the wayleaves. Any change of use may result in significant legal challenges and further financial outlays that have not been considered as part of this Project.

7.3 | Sensitivities

Decommissioning cont'd

Decommissioning basecase vs sensitivity comparison for all 3 scenarios

		Basecase		Sensitivity	
	Scenario	km	£bn	km	£bn
NTS grouting @ 50% MEAV	High	-	-	-	-
	Balanced	3,051	12.2	610	2.4
	Low	4,576	18.3	915	3.6
NTS capping @ 10% MEAV	High	-	-	-	-
	Balanced	-	-	2,441	1.9
	Low	-	-	3,661	2.9
LTS grouting @ 50% MEAV	High	-	-	-	-
	Balanced	8,115	4.8	1,623	0.9
	Low	11,592	6.9	2,318	1.3
LTS capping @ 10% MEAV	High	-	-	-	-
	Balanced	-	-	6,492	0.7
	Low	-	-	9,274	1.1
Distribution grouting @ 50% MEAV	High	-	-	-	-
	Balanced	-	-	12,935	5.6
	Low	-	-	17,247	7.5
Distribution capping @ 10% MEAV	High	-	-	-	-
	Balanced	-	-	187,116	9.6
	Low	-		249,488	12.8
Total decommissioning costs	High	-	-	-	-
	Balanced		17.0		21.4
	Low		25.2		29.5
Total scenario costs	High	-	-	-	-
	Balanced		59.0		63.4
	Low		69.9		74.2

Figure 33. Balanced: Basecase vs Sensitivity decommissioning comparison

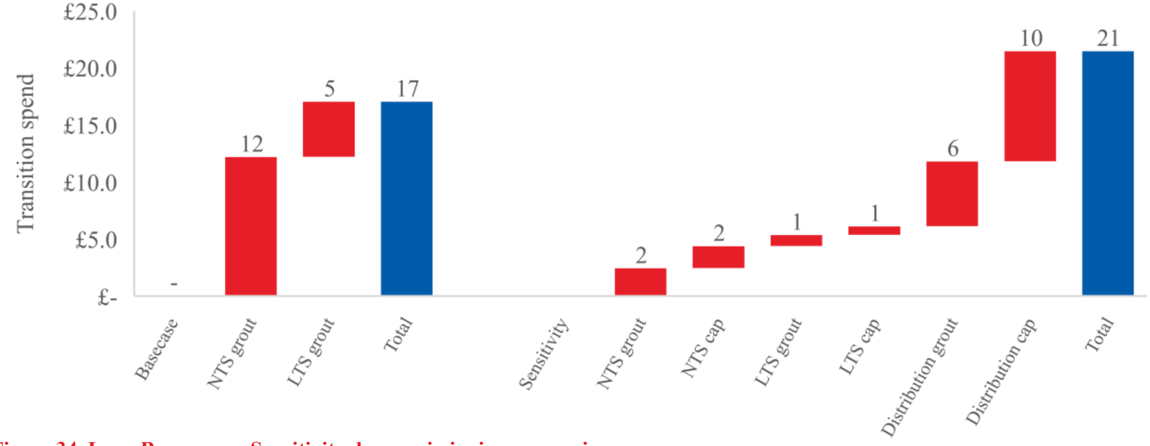
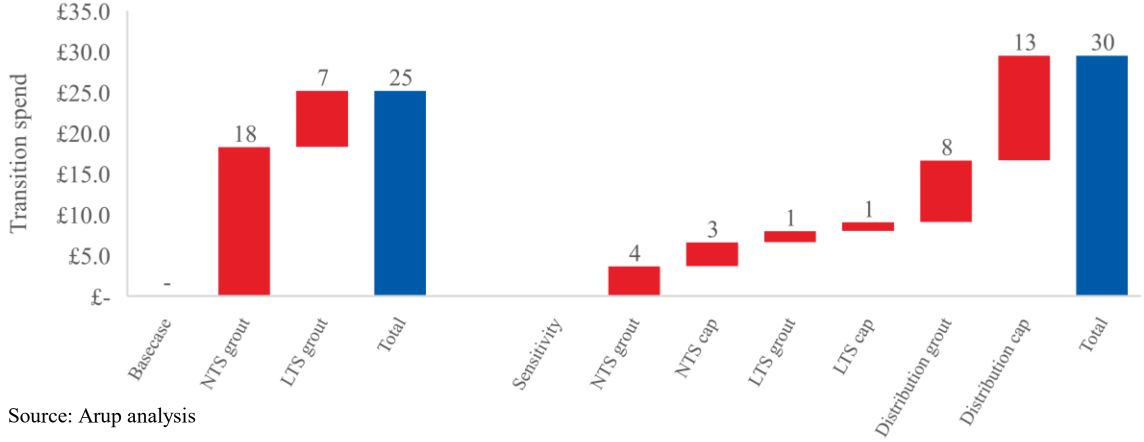


Figure 34. Low: Basecase vs Sensitivity decommissioning comparison



Source: Arup analysis

7.3 | Sensitivities

Summary

The aggregate impact of the sensitivities are displayed for each of the scenarios opposite.

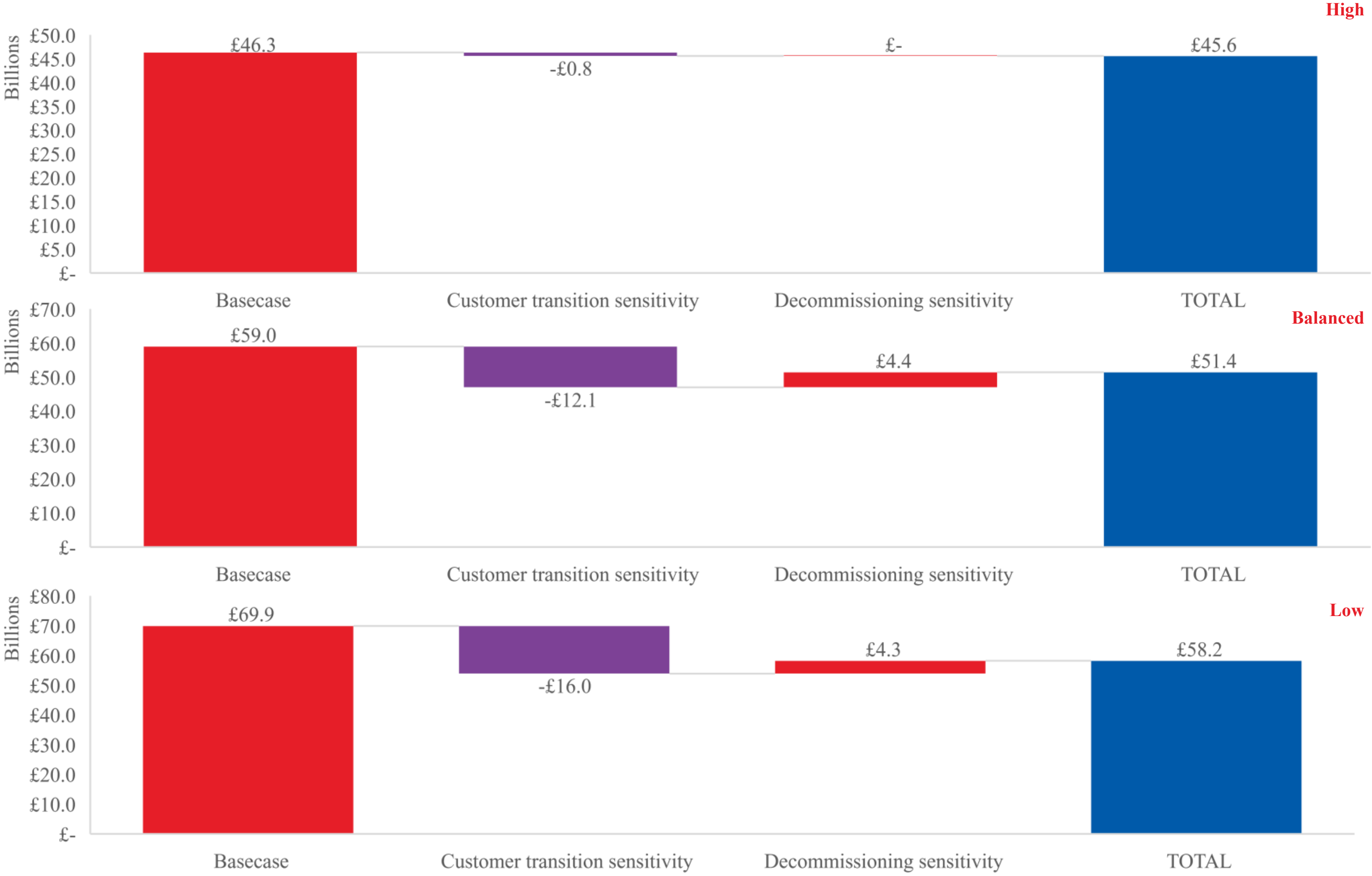
Given the limited impact customer disconnections have in the High scenario, and the lack of envisaged decommissioning, the impact on high is negligible.

Balanced and Low exhibit more significant impacts from the sensitivities, albeit some of the gains made in the customer disconnections are offset by the increases in decommissioning costs.

Overall, the results are broadly unchanged:

- All scenarios require significant investment in the gas networks to achieve, with costs estimated between £46-70bn.
- The customer transition sensitivity has a material impact on the overall costs for Balanced and Low, reinforcing Arup's recommendations or further work in this area.

Figure 35. Aggregate impact of sensitivities across the scenarios



Source: Arup analysis

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7.4 | Phasing of works

Critical path

Summary

There will be major deliverability challenges across all three scenarios; in all 3 instances there is a significant amount of enabling works as well as direct infrastructure investment required. These include, but are not limited to: planning and permitting, societal impact, natural capital, supply chain, labour force capacity etc.

The timeline below shows the critical path to deliver hydrogen uptake requirements across the scenarios. Overall, there are 2 key takeaways from the below schedule:

The schedule is already highly compacted in order to meet the net zero date of 2050. Arup consider this schedule to be ambitious, when considering the scale of works and the supply chain's lack of recent experience in mobilising to such a scale.

In all scenarios there is a significant amount of direct infrastructure works at a national scale.

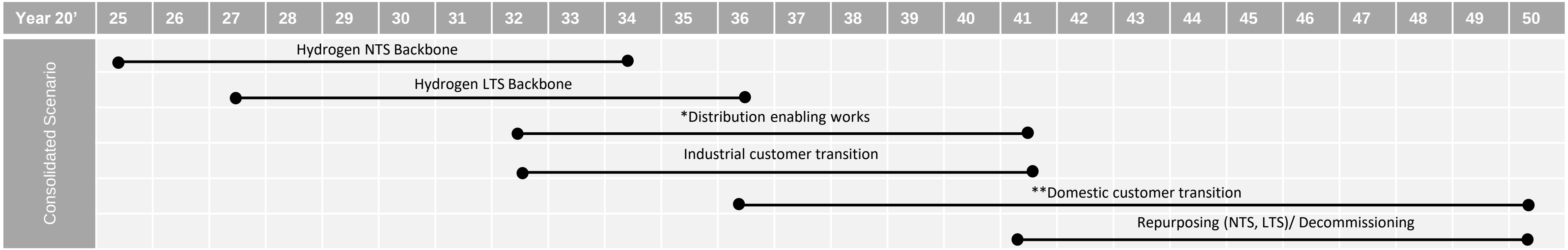
Furthermore, there are significant enabling works e.g. law/regulation changes, permitting, additional R&D etc. that are required in addition to the activities outlined below.

As discussed in the sensitivity analysis on decommissioning, Arup consider this a decision of last report that would likely happen post 2050. It has been included in this timeline to achieve the overall aims of this project.

Notes

*There are no distribution enabling works in the low scenario.

**Domestic customer transition works will begin in 2031 in the low scenario.



7.4 | Phasing of works

Critical path

Key dates

1 2032 is the first critical date across all scenarios, whereby industrial customers start receiving hydrogen. For this to occur, this project considers that a new build hydrogen backbone will be required to link all of the industrial clusters and provide transmission and security of supply capability for industrial users.

The detailed rationale for this backbone being new build has been discussed at length in this report, however this schedule illustrates the fact that by the time such a backbone is needed, natural gas volumes are unlikely to have reduced sufficiently to allow conversion.

The implications of this date are that a new build, national hydrogen backbone of c. 2,000km would be required to be in operation by 2032. Given the scale of these work, Arup have assumed a 10-year programme commencing in 2025, with the fist industrial customers connected in 2032.

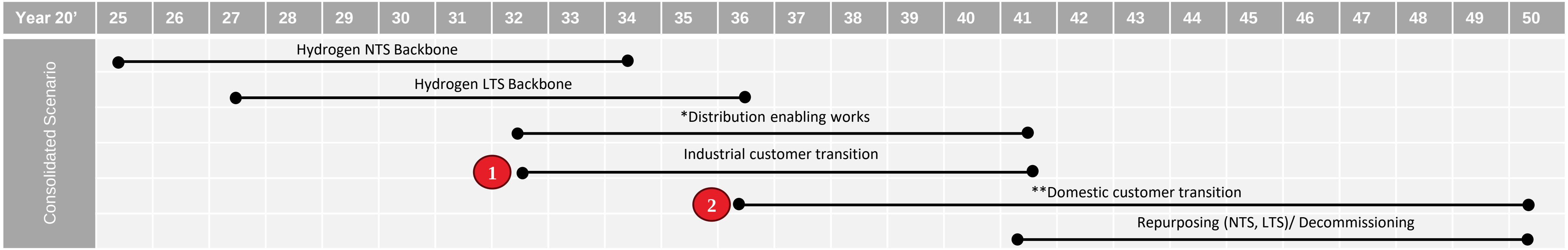
→ Under all Scenarios, FID on this hydrogen backbone is needed by 2025.

2 2036 is the next critical date on the schedule, whereby domestic customers start receiving hydrogen / customers start to disconnect from the gas network. In order for this to happen, a significant amount of works are required:

- For hydrogen conversion; a national hydrogen transmission network is required, with a corresponding LTS backbone is required to distribute hydrogen within regions; the distribution network must be made hydrogen ready, with all the iron mains replaced; customer equipment must be hydrogen ready
- For gas network disconnection; the electrical networks would need to be able to manage the increase in load (not in scope but a significant factor that should be investigated further); customer premises converted to an alternative energy supply; a labour force skilled up to manage the workload relating to disconnections.

Given the scale of these works, Arup consider 2036 to be ambitious. The project team assert that the enabling works would likely be done in a strategic manner nationally, in order to prioritise certain regions to meet the 2036 target.

Furthermore, Arup do not consider there is scope to delay domestic customer transition, with the below programme assuming a conversion rate of 1.5m customers per annum. This is comparable to the Towns Gas conversion, but is still considered highly challenging by the Stakeholder group.



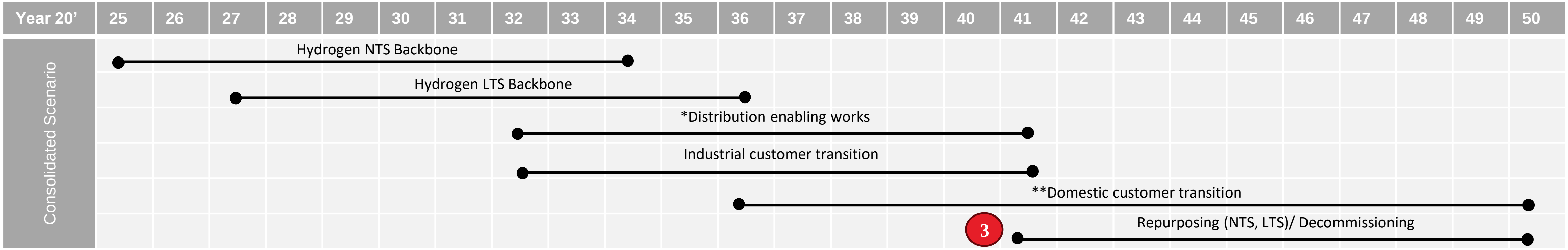
7.4 | Phasing of works

Critical path

Key dates

3 Repurposing of the NTS and LTS has been modelled within the 2050 timeframe for the purposes of this study.

Where metallurgy or condition don't present an issue and therefore minimal cost, (for c. 80% of the network), Arup consider this timeframe appropriate. However, there remains a high degree of uncertainty as to how to manage the remaining 20% of the network. For example, could these portions of the network be repurposed or would they require replacement or decommissioning.



8 | Conclusions & recommendations

8 | Conclusions & recommendations

Summary

As per the aims and objectives of this project, the three transition scenarios have returned a spread of illustrative costs. The High scenario results in the lowest cost, whilst the Low scenario results in the highest cost to the gas system.

The cost driver analysis demonstrates that direct infrastructure investment as a result of the technical and operational differences between hydrogen and natural gas is not as integral to the overall cost build up as is perhaps thought.

The analysis provides useful early insights to guide further work in this important area. In particular, the following areas require more research to strengthen the evidence base for the analysis and thereby reduce some of the associated uncertainties:

Immediate decision making required

The analysis demonstrates that under all scenarios, key decisions around GB's future energy mix need to be made imminently, with infrastructure projects of a national scale commenced by the mid-2020s.

Any delays would likely put additional pressure on an already ambitious programme, likely resulting in missed 2050 targets.

Wider energy sector interdependencies

In all scenarios there is a need to replace the energy currently delivered via Natural gas with energy that has been made; either in the form of electrons or electrolysis-derived hydrogen. Significant scaling up of renewable electricity generation is required now to meet the green hydrogen demand projected in the high and balanced scenario, or to achieve decarbonisation of sectors via electrification in the low scenario, as well as potential upgrades to the associated electrical transmission and distribution infrastructure. Ultimately, achieving the outcomes set out across all scenarios is interdependent on other decisions and corresponding progress in the whole energy sector.

Challenge of 2050

All scenarios present a significantly compressed programme of works, with many highly significant enabling factors unaccounted for (Project is limited by its scope).

All scenarios present a scale of works likely not seen in the last 50 years, bringing significant programme and deliverability risk.

Given the compact nature of the timelines, and the scale of work to be delivered, this Project considers meeting the 2050 targets to be challenging, particularly given the fragmented nature of the current energy industry. Further work should be undertaken to consider the sort of delivery model required.

The need for a new build hydrogen backbone

Given the timings of hydrogen delivery to customers (both domestic and industrial), this Project asserts that a backbone of c. 2,000km is required as a new build project.

Whilst it is possible to repurpose the existing NTS, the future natural gas demand will not have dropped sufficiently to free up the headroom in the existing network.

This new build backbone will start the mass transition of customers away from Natural gas (even in the Low scenario).

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8 | Conclusions & recommendations

Summary cont'd

Uncertainty

As summarised in our report, there is a high degree of uncertainty with regard to transition research to date, both in terms of technical assumptions and cost assumptions. Additionally the mechanics of how the energy system transitions at a system level and the customer journey, experience and support in transition is largely unknown and is not considered in the current industry research. This project highlights some of the more challenging aspects of transition and identifies a number of areas where further research is key, particularly the following themes:

Technical Requirements

Several projects are investigating the ability to convert the transmission and distribution networks. In terms of readiness works: steel grade is a likely driver of pipeline replacements in order to make the network hydrogen ready and changes to meters and valves are expected due to the differences between natural gas and hydrogen composition.

As demonstrated in Section 7, direct infrastructure costs are particularly significant in the High scenario (albeit this scenario is the lowest cost overall), with the sensitivity analysis highlighting the significant impact small changes in these assumptions could have on overall costs.

Domestic conversion – disconnecting from the gas network

The conversion activities required within the home are clear however this project recommends further research and stakeholder engagement on this topic is required. This project demonstrates that customer conversion is not only one of the biggest challenges in terms of logistics, but is also one of the largest drivers of spend.

As described in the sensitivity analysis, Arup consider there are a number of interventions that could have a significant impact on the logistical / legal complexity of the gas disconnections. If these activities can be simplified, the problem then trends towards a logistics / workforce mobilisation driven activity. Arup consider a dedicated entity could carry out this licensed activity, leaving the networks to focus on the challenges associated with de-energising the networks and either decommissioning them, or transitioning them to hydrogen.

Decommissioning

HSE's decommissioning guidance is relatively high level, and does not provide a methodology to consider a project to the scale of decommissioning the entire gas system. Arup expect more consideration is given to developing a system wide decommissioning methodology, that takes a risk base approach to maximising risk reduction whilst minimising the financial impact of doing so.

This approach is considered similar to the current guidance in the offshore oil and gas industry. Once the methodology is more certain, a more accurate cost estimate can be carried out to refine the forecasts presented in this report.

9 | Appendix

9.1 | References

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