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Future Operability of Gas for System Integration (FOGSI) Alpha

Final Report

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Executive Summary

The FOGSI Alpha phase has delivered a proof-of-concept model of a future integrated electricity and hydrogen system for Great Britain. The work was undertaken to address an identified capability gap: while there are established approaches for modelling electricity networks and gas or hydrogen networks separately, there is limited capability to examine their operational interaction in an integrated way at transmission scale, particularly where gas dynamics, linepack and cross-system constraints materially affect feasibility. The model developed in this phase links a representation of the proposed Project Union hydrogen transmission network, an electricity transmission and dispatch model, and the principal assets that connect the two systems, including electrolysers and hydrogen-fuelled thermal generation. This provides a credible basis for understanding how future electricity and hydrogen systems may need to operate together.

The proof of concept has been applied to a set of representative days with challenging operating conditions using two approaches: a staged approach, in which electricity outcomes are passed to the hydrogen system, and a coupled approach, in which the electricity and hydrogen systems are solved together. This allows the project to test both the consequences of imposing electricity-led hydrogen requirements on the hydrogen network and the effect of recognising hydrogen network constraints directly in the optimisation. The model is run in hourly timesteps over each day and includes operational restrictions relating to electricity boundary flows, pressure limits, linepack change and electricity system operability.

The key technical learning from the results is that, if the future electricity and hydrogen systems are not considered together, the electricity system can place infeasible demands on the hydrogen network. When the systems are considered together, national aggregate outcomes can remain broadly similar in some cases, for example in total curtailment or electrolysis, but the feasible timing and location of dispatch can change materially once hydrogen network constraints are taken into account. The results also show extensive use of linepack, highly variable gas flows and compression requirements, and significant variation in the spatial distribution of hydrogen through the day. Taken together, these findings show that apparently similar aggregate outcomes can conceal materially different operational requirements and infrastructure needs, and that simplified assumptions based only on aggregate balances may miss important deliverability constraints and inefficiencies.

From the proof-of-concept model developed in this phase, it is therefore possible to examine a useful set of questions for future whole-system assessment. These include how challenging operating conditions propagate across both systems; how hydrogen production, transport, storage and use interact with electricity system conditions; where hydrogen network constraints materially affect the feasible operation of electrolysers and hydrogen generation; and how linepack and the spatial distribution of hydrogen influence system operability. The current results are based on representative single days and therefore do not yet capture sequential operation over longer periods, uncertainty, or additional requirements such as more detailed ancillary service provision, unit commitment and fuller security constraints. However, the work has shown clearly why these areas matter and where further development should focus.

The implication for a future Beta phase is not simply to extend the size of the model, but to mature it into a more robust capability that can support medium- to long-term whole-system assessment and, in time, routine business use. This will require improvements in the treatment of uncertainty, longer-duration and stress-period analysis, cost representation, and the testing of alternative network constraints and investment options. It will also require practical development around APIs, data integration, governance, ownership, training and technical deployment, so that the model can be embedded within existing industry environments rather than remaining a stand-alone prototype. In that sense, the principal value of the Alpha phase is twofold: it has demonstrated the relevance of integrated electricity-hydrogen operational modelling, and it has clarified the technical, organisational and analytical priorities for the next phase of development and beyond.

Contents

Table of Figures

Table of Tables

Introduction

To achieve our net-zero goals, it is likely we will need a much tighter coupling between our electricity system and a future hydrogen system. Efficient use of green hydrogen and avoiding the curtailment of renewables will be core targets of system operation. In addition to these operational goals, there will be a strategic goal: sufficient infrastructure needs to be built to cope with high transport volumes of electricity and hydrogen. To serve both objectives, efficient operational models are necessary. This is the aim of the Future Operability of Gas for System Integration (FOGSI) project.

During the Discovery[1] phase of this project, we identified two major gaps in the current landscape of tools:

a) dealing with operational constraints of the gas network, gas storage, and electrolysers,
b) fully incorporating uncertainty in the decision-making process.

To deal with the uncertainties of hydrogen systems, the aim of this project is to develop tools that will reflect the complexity of future operational decisions where the gas and electricity systems are more tightly coupled. These tools can then be incorporated into the medium to long-term planning processes to support the efficient planning and operation of the future system. To do this, these tools will allow the hydrogen network to have the ability to support the production of hydrogen from excess renewables and ensure that hydrogen from storage sites can be quickly transported to power plants in times of low renewable availability. It will also help both hydrogen and electricity network planners to understand the operational restrictions that drive network expansion requirements.

To achieve this goal, we need to ensure that the operational restrictions of the gas storage operators, the gas network, but also the electricity network are adequately modelled. To address the identified gaps, we will focus on the modelling of the operations of the gas network, the gas storages, and the electrolysers and use the off-the-shelf solutions for our electricity network model.

We will propose interfaces between the different model components to allow the different actors (e.g. NG, NGET and NESO) with different responsibilities to interact with each other within this project.

In this Alpha project, we have developed a proof-of-concept model that demonstrates the complexity of operational decision making in a tightly coupled hydrogen and electricity system of the future. In a future Beta project, we anticipate the focus would be on the linking up existing models across the energy system, but this was not possible withinthe focus of this work has been to develop the models and the coupling required to effectively capture the operational complexities of multi-vector decision making.

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[1] Realistic Modelling of Power to Gas Operability, SIF Discovery Project, 2024

This report details the technical work delivered during the Alpha project, the implementation considerations for Beta and beyond into commercialisation and rollout, and the cost-benefit analysis carried out.

Chapter 1 provides a summary of the literature review and highlights the key gaps this work aims to address. The full literature review is presented in Annex A. Chapter 2 covers the model design and development in detail, including the technical requirements and the options for how to approach each element and interaction in the coupled system. A full mathematical specification of the model is given in Annex B. Chapter 3 outlines the key inputs and assumptions for the energy networks developed and the future scenario considered, as well as the example days chosen to illustrate challenging operational circumstances. Chapter 4 discusses the model results and insights from the use cases considered. Chapter 5 outlines the implementation requirements and the options considered for a future Beta project and transitioning to BAU. Chapter 6 covers the cost benefit analysis for the project, including the key updates from the assessment included in the Alpha application. Finally, the conclusion of this work and planned future direction for a Beta project are discussed.

Chapter 1: Literature Review Summary

This chapter provides a summary of the key learnings from the Literature Review, identifying the gaps in current academic research and industry practice, and outlining what FOGSI aims to address.

To establish the state-of-the-art capabilities and pinpoint the specific research gaps FOGSI targets, the project team conducted a comprehensive review spanning academic publications, off-the-shelf modelling tools, and GB energy network licensee-led innovation projects.

The full literature review detailing this analysis is included as an Annex to this report.

Key Findings: Academic Research

The review analysed 63 academic papers identified as most relevant to FOGSI, structured into four thematic areas:

- Power system modelling (14 papers, 1979–2024)
- Gas and hydrogen network modelling (22 papers, 2007–2025)
- Modelling of coupling technologies (3 papers, 2020–2023)
- Integrated gas and power system modelling (24 papers, 2008–2025)

A recurring theme across the literature is the fundamental trade-off between physical fidelity and computational tractability. While standalone power and gas modelling are highly mature fields, coupling these interdependent networks, which operate on fundamentally different timescales, presents a major mathematical challenge. Advanced power system models are highly specialised for fast-acting dynamics but are not inherently designed to integrate with the slower, physically complex dynamics of a national gas network. Conversely, simplifying the gas physics to force this integration can lead to a significant overestimation of network flexibility, presenting a direct risk to operational security.

The specific gaps identified in the academic literature, alongside FOGSI's targeted approach to resolving them, are summarised in Table 1. As the table highlights, relying on overly simplified models can create physically unrealistic outcomes, while high-fidelity transient models remain too computationally intensive for operational use at a realistic, system-wide scale. FOGSI therefore targets a mathematical "middle ground", aiming to create a framework that preserves the key physical constraints needed for credible GB-relevant analysis without sacrificing tractability.

The team also surveyed existing public and academic software tools to assess the landscape of available modelling frameworks. While powerful off-the-shelf tools exist for analysing individual energy networks (either power or gas in isolation) or for high-level, long-term whole energy system planning, the review found no off-the-shelf tool surveyed that can perform detailed, transient, integrated operational analysis of coupled gas and electricity networks. This confirms the specific capability gap that FOGSI is designed to address.

Table 1 Key gaps identified in academic research

Identified Gap	FOGSI Focus
Fidelity vs. Scalability: Fast, simple models miss key dynamics, while accurate, transient models are too slow for operational use.	**Develop Accurate & Scalable Models:** Combine approaches to create a framework that is both physically realistic and computationally tractable for GB-relevant cases.
Overstated Linepack Flexibility: Simplified models create physically impossible schedules by allowing unrealistically fast pipeline charge/discharge.	**Ensure Plans are Physically Achievable:** Design and validate physics-aware models that respect real-world constraints and ensure operational feasibility.
Uncertainty in Coupled Systems: Few tools combine realistic, transient gas physics with supply-side uncertainty from renewables and electrolysis.	**Model Weather-Driven Scenarios:** Build and test the system against explicit, weather-driven uncertainty to understand risks and improve resilience.
Missing Interdependencies: Models often omit key links (e.g., compressor power) and fail to coordinate fast (power) and slow (gas) timescales.	**Capture the Whole System:** Include missing interdependencies in a scalable framework and develop methods for cross-timescale coordination.
Underused Component Physics: The detailed physics of new technologies (e.g., electrolyzer efficiency) are not used in system-wide models.	**Integrate High-Fidelity Components:** Develop accurate but tractable models of new technologies to properly assess their system-wide impact.
Lack of GB-Specific Validation: A shortage of standardized, GB-relevant scenarios and reproducible testing processes exists.	**Provide a GB-Ready Toolkit:** Create GB-specific datasets and a rigorous, repeatable pipeline for model validation and benchmarking.

Key Findings: Innovation Projects

To understand the current landscape of applied industry research, the project team reviewed 90 GB energy network licensee-led innovation projects (comprising 26 live and 64 completed projects across the Strategic Innovation Fund (SIF) and Network Innovation Allowance (NIA) frameworks). Information was primarily sourced from the Smarter Networks Portal, supplemented by the Future Energy Networks portal (noting that publicly available project documentation varies in depth and consistency).

The review analysed projects across a wide range of themes spanning decision-support and control, digitalisation and digital twins, scenario development and extreme events, and evolving gas/hydrogen operability and storage, including cross-vector dependencies and constraints. A major finding is that while there is a wealth of innovation to build upon, the current trajectory of GB innovation projects leans heavily toward data integration, visualisation, and local/regional planning, rather than system-wide, automated operational decision support. For instance, while "Digital Twins" are a highly active area of innovation, many projects focus on data gathering/processing/exchange and visualisation for control-room use, rather than embedding integrated optimisation for coupled gas–power operational decision-making.

The specific gaps identified across the GB licensee innovation landscape, and FOGSI's focus in addressing them, are summarised in Table 2. Ultimately, the review of innovation projects indicates that detailed, simultaneous co-optimisation of electricity, gas, and coupling technologies, especially at national transmission scale and when considering stress conditions (e.g., extreme events and weather-driven variability), remains a significant gap in the current GB innovation portfolio.

Table 2 Key gaps identified in innovation projects

Key gap	FOGSI focus
Innovation projects focus on local planning or stakeholder behaviour, lacking a unified national transmission model.	Develop a holistic, physics-aware operational model for the national transmission system to assess system-wide impacts and trade-offs.
Scenario-building projects neglect the detailed operational feasibility and control strategies needed to manage extreme events.	Test the operational viability of future energy scenarios, especially under extreme conditions, by generating robust, coordinated control actions.
Digital twin projects focus on data and visualization, not integrated operational optimization.	(Future) Embed the optimization tool within a digital twin framework to enable automated, forward-looking operational planning.

Conclusion and FOGSI Focus

The combined findings from the academic and innovation reviews identified a clear capability gap in the GB context. While there are mature approaches for modelling electricity and gas networks in isolation, and substantial innovation activity in data integration, visualisation, and local/regional planning, the reviews found limited capability to carry out operationally grounded, integrated analysis of coupled gas/hydrogen and electricity systems at transmission scale, particularly where gas dynamics, linepack, and interactions between the networks materially affect feasibility and flexibility.

In response, FOGSI was positioned to address this gap by developing an integrated modelling framework that balances physical realism with computational tractability for GB-relevant operability questions. For the Alpha phase in particular, FOGSI aimed to deliver a foundational proof-of-concept: demonstrating the key interdependencies between electricity, gas/hydrogen networks, coupling assets, and storage, and establishing a credible basis for subsequent enhancement in later phases.

Chapter 2: Model Design and Development

The FOGSI model was developed to address a critical gap in whole-system energy planning: the need for an accurate, scalable framework that captures the complex physical interdependencies between national gas and electricity infrastructure. To achieve this, the model has been developed in three distinct but mathematically integrated parts:

- **The gas system**, which models the time-varying physics of a single-species gas transmission network (representing the proposed Project Union hydrogen backbone).
- **The electricity system**, which models dispatchable generation, flexible demand, and the high-voltage electricity transmission network.
- **The coupling system**, which provides the physical and mathematical bridge linking the two networks through electrolysers and hydrogen-fuelled thermal generators.

High-level model structure is depicted in Figure 1.

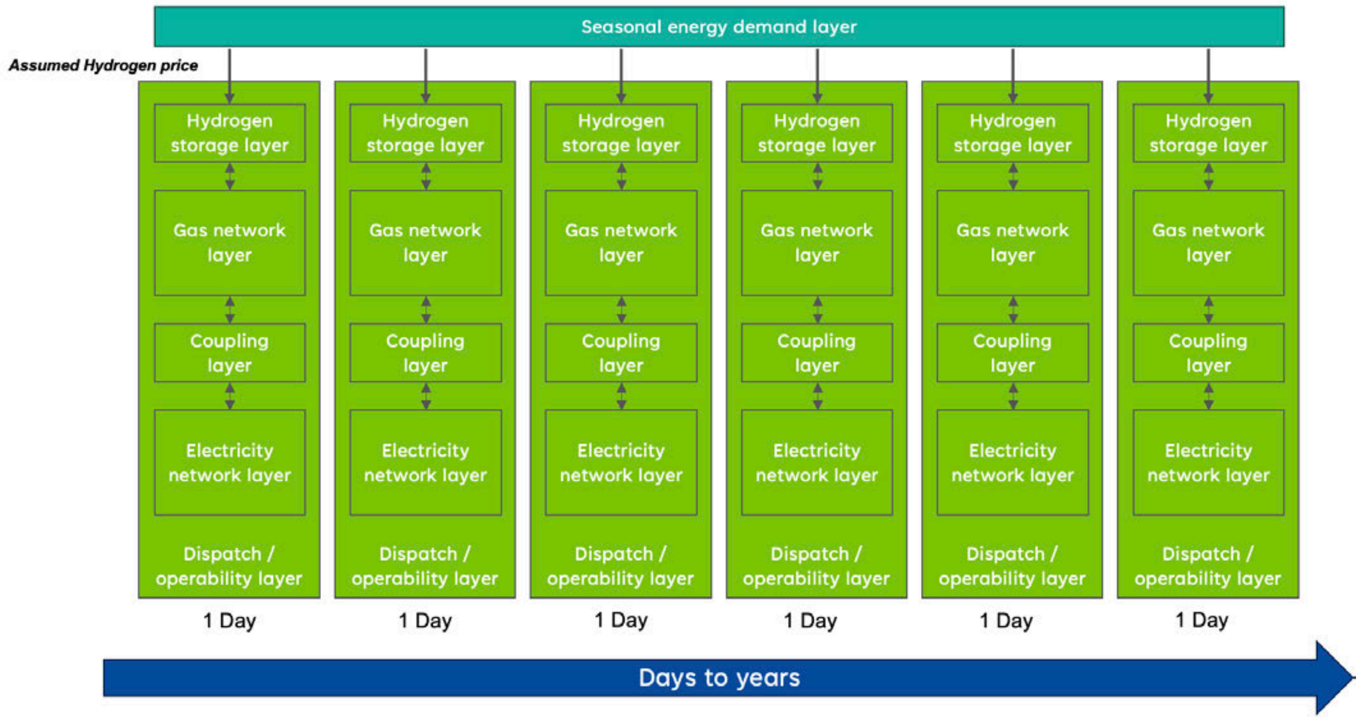

Figure 1 High-level model structure

Ideally, and in the plan for a future Beta project, we would want to focus on linking existing models and specifying their interfaces and interactions, following the structure outlined above. However, this was not possible during Alpha therefore the work presented here documents how we have developed each of the models and specified their interactions. This has allowed us to demonstrate how the operational complexities of a future tightly integrated hydrogen and electricity system would operate to explore the impacts and decision-making actions in each vector and for the coupled system overall.

System Components

To ensure adaptability and futureproofing, the model is built upon a modular, object-oriented software architecture using Python and the Pyomo optimisation library. The system is constructed from distinct building blocks, allowing planners to seamlessly create, modify, or remove various components of the electrical and gas grids. This modularity ensures the tool is highly flexible, enabling the rapid testing of diverse future energy scenarios, changing technology efficiencies, or alternative infrastructure topologies without requiring a redesign of the core physics engines. The code architecture is given in Figure 2.

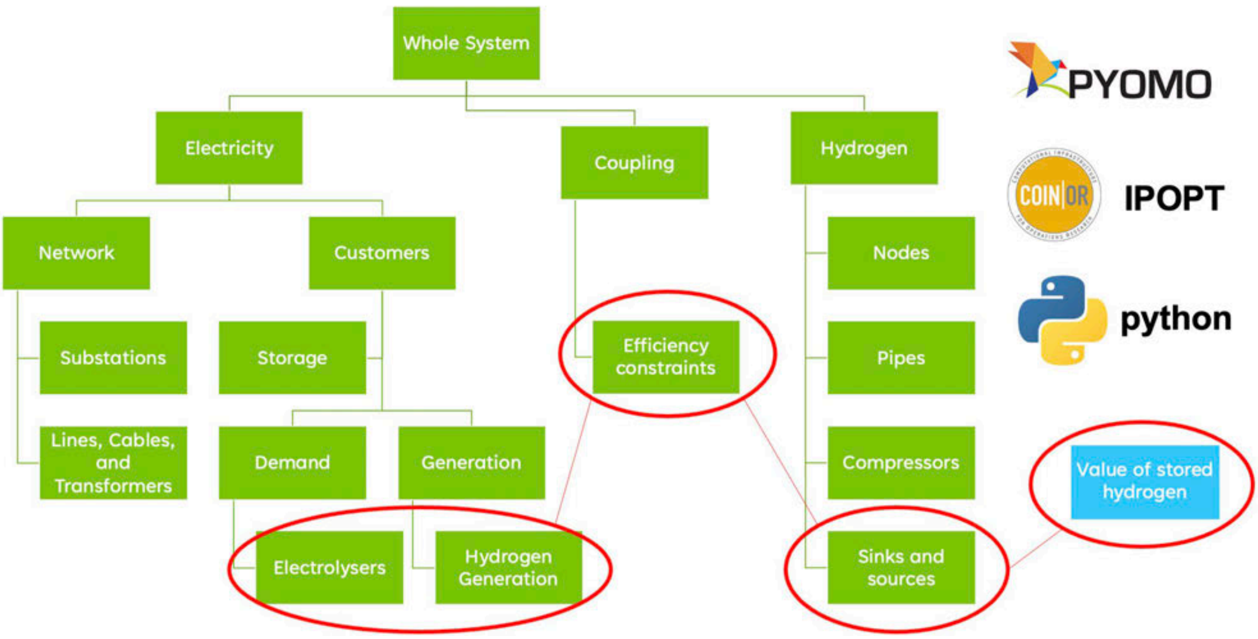

Figure 2 Code architecture

The general model options considered are summarised in Table 3.

Table 3 General model options

Modelling choice	Options	Selected option
What time granularity should we select?	**Option 1:** Daily **Option 2:** Hourly / half-hourly	**Option 2**
What time horizon should we model?	**Option 1:** Individual timesteps **Option 2:** Short sequences of timesteps (e.g. a day, half-hourly) **Option 3:** A full year	**Option 2**
What should we assume about connected European energy systems?	**Option 1:** Full pan-European model **Option 2:** GB model only **Option 3:** Simplified representation of European links	Implemented **Option 2**. The data required for **Option 1** and the computational expense are prohibitive for the Alpha. We will explore **Option 3** in our use cases (e.g., "what if there was abundant electricity available from Norway).
How much focus should there be on prices?	**Option 1:** Focus only on system constraints **Option 2:** Estimate the cost of operating the system alongside operability	As this project is focused on operability, we will select **Option 1**, and model elements of system cost where necessary. More detailed price estimation can be added if possible.

The full mathematical model description is included as an Annex to this report.

Electricity Network

The electricity network model has been developed using openly published data wherever possible (including the Electricity Ten Year Statement (ETYS[2]) and Future Energy Scenarios (FES[3])). Where specific technical assumptions have been made, these were rigorously reviewed and validated by National Grid Electricity Transmission (NGET), ensuring the inclusion of accurate tap changer settings, short-term emergency ratings, and transformer constraints.

Crucially, the model goes beyond simple supply-and-demand balancing by solving for Non-linear AC Optimal Power Flow (ACOPF). This allows the tool to accurately capture transmission losses, manage reactive power, and enforce statutory voltage limits. Furthermore, the model incorporates stringent "Grid Operability" constraints. By explicitly enforcing System Non-Synchronous Penetration (SNSP) limits and minimum System Strength (inertia) requirements, the model ensures that any hydrogen-related dispatch decisions respect the physical stability limits of the Great Britain power grid under high renewable penetration.

The electricity model options considered are summarised in Table 4.

Table 4 Electricity model options

Modelling choice	Options	Selected option
Representation of detailed technical factors (voltages, losses, reactive power)	**Option 1:** Assume all of these are negligible (so-called "DC load flow") **Option 2:** Simplified treatment of some (e.g. approximate voltages and reactive power, no losses) **Option 3:** Full non-linear "AC load flow" model	Model set up to be flexible. Results shown mainly with **Option 1**. **Option 3** possible but increases run-time.
What is the spatial granularity and scale of model	**Option 1:** Model entire network in detail **Option 2:** Model one region of the network **Option 3:** Model one region of the network in detail, with simplified treatment elsewhere	**Option 3**: GB network likely to be too large to model all in detail, but would like to see some of the details around key areas (like electrolysers in Scotland and CCHT in North-East England)
Do we represent unit commitment constraints (i.e. minimum stable levels of generation, start up and shut down costs etc)	**Option 1**: Model the binary decision of whether or not to commit a generation **Option 2:** Ignore this binary constraint, allow for unrealistic generation outcomes.	**Option 2** in all cases. This may only be possible for some generators in certain areas.
How do represent the security requirements of the network?	**Option 1:** Adding extra security constraints to the model to ensure post-fault security of the network. **Option 2:** De-rate the capacities of network assets to approximately account for the impact of network security.	Will implement **Option 2** in the first instance. Did not have time to explore **Option 1**.

Gas Network

The gas network model provides a high-fidelity representation of the Project Union hydrogen transmission system. Unlike simplified steady-state models that look at isolated snapshots in time, the FOGSI gas kernel utilises a "transient" (time-varying) formulation. This is a vital capability because gas does not move instantaneously.

By modelling the friction-dominated physics of gas flow over time, the tool can accurately quantify and utilise "linepack"—the inherent ability of the high-pressure pipelines to act as a physical storage buffer. The model tracks hour-by-hour changes in nodal pressure and gas density, constrained by safe operational limits and compressor capacities. This allows planners to

[2] ETYS documents and appendices, NESO, 2024
[3] Future Energy Scenarios, NESO, 2025

see exactly how the pipeline's flexibility can be leveraged to absorb excess wind generation (via electrolysis) and reliably deliver fuel to thermal power plants when grid demand peaks.

The gas model options considered are summarised in Table 5.

Table 5 Gas model options

Modelling choice	Options	Selected option
Which gases do we model?	**Option 1:** Hydrogen only **Option 2:** variable blending natural gas, hydrogen	**Option 1:** We focus on Project Union as the future hydrogen backbone network
What do we assume about the rate at which gas moves through the system?	**Option 1:** Assume gas travels instantaneously between locations. **Option 2:** Assume the rate at which gas moves is finite, need to consider the dynamics of this.	**Option 2:** Finite speed of compressing / moving gas is central to some of our use cases and needs to be modelled.
What is the spatial granularity and scale of model	**Option 1:** Model entire network in detail **Option 2:** Model one region of the network **Option 3:** Model one regio of the network in detail, with simplified treatment elsewhere	**Option 1**: Particularly focused on how hydrogen network interacts with transmission constraints (e.g. from generation locations in Scotland to demand and storage sites much further South
What does the model assume about gas temperatures?	**Option 1:** Constant gas temperature **Option 2:** Variable gas temperature	**Option 1:** For Alpha, an isothermal model is good enough to show value in the use cases

Coupling

The coupling layer acts as the mathematical handshake between the electron and molecule domains. It provides a highly granular, location-specific mapping that links individual electrical substations directly to specific nodes on the Project Union gas network.

This system enforces the strict conservation of energy between the two grids. It calculates the conversion of electrical power (MW) into physical hydrogen mass flow (tonnes/hour), meticulously accounting for the technology-specific efficiency curves of electrolysers and Combined Cycle Hydrogen Turbines (CCHTs). By embedding this conversion logic directly into the model, FOGSI can identify the locational benefits of siting coupling assets at specific grid bottlenecks.

The coupling component options considered are summarised in Table 6.

Table 6 Coupling component options

Modelling choice	Options	Selected option
What do we assume about how hydrogen electrolysers behave?	**Option 1:** Assume these are a simple constant efficiency / production level (e.g., X MWh of electricity creates Y m^3 of hydrogen at Z pressure). **Option 2:** Detailed model of heat balance within an electrolyser. **Option 3:** Intermediate complexity.	Will implement **Option 1** in the first instance. Did not have time to explore **Option 3**. Hydrogen electrolysers with local renewable production will be treated as pure hydrogen sources, rather than coupled components.
What do we assume about the behaviour hydrogen generators?	By and large, we will assume these behave like other gas generators. Some aspects might need to be considered in more detail (e.g., the hydrogen that needs to be used in advance to startup a generator)	

Integrated Model Structure

The overall FOGSI framework operates as a unified co-optimization engine. Rather than solving the gas and electricity networks sequentially, which can lead to physically infeasible schedules, the model solves them simultaneously across a defined time horizon (e.g., a 24-hour day).

This "first-discretise-then-optimise" approach evaluates the system using a time-expanded graph. The solver is able to make forward-looking, globally optimal decisions, such as utilizing cheap renewable electricity to produce and store hydrogen in the network linepack early in the day, anticipating the need for synchronous generation to support grid inertia during the evening peak. To represent operation over longer periods within the scope of Alpha, the model includes a "hydrogen storage layer[4]" that applies cyclic constraints and economic valuations to stored hydrogen, linking daily dispatch decisions to longer-term energy requirements.

[4] Note that there are two underlying assumptions here. Firstly, we generally assume that we have a period where there is ample hydrogen available, therefore we focus on the decision making for the hydrogen system (rather than for methane, as burning hydrogen would be preferable). Secondly, by focussing on hydrogen decision making, we implicitly assume that the methane network is unconstrained. We plan to revisit (and potentially relax) both of these assumptions in Beta.

Chapter 3: Inputs and Assumptions

This section describes the information, data, and assumptions used to populate the model.

While the inputs to the model and its outputs must be plausible, they are not intended to be projections of what might happen in an integrated energy system, and some specific assumptions and combinations of inputs may prove to be somewhat unrealistic. In some cases, we have made assumptions (e.g. about the relative price of hydrogen generation versus gas with carbon capture) to promote certain behaviours in the model. However, our main goal within the Alpha is to demonstrate the possible operational impacts of coupling the models together, rather than predict what will actually happen.

Networks

The model includes detailed representations of both [redacted] hydrogen gas network, and the National Electricity Transmission System (NETS).

Project Union network

Baseline pipe data (including geometry, length and diameter) was sourced from the National Gas website[6]. This dataset includes more than 1000 pipes with diameters between 150mm to 1200mm.

The following procedure was used to process the network:

1. Pipe end points were identified based on the geometry of the GIS data.
2. Nodes that were very close to each other (within 6 km) were merged. This is to ensure the network is connected, and to remove very short pipes which could introduce numerical instabilities.
3. Narrow pipes (initially, with diameter less than or equal to 300 mm) were removed, as the information that was shared by National Gas did not include such narrow pipes. In our final model runs, we further increased the minimum pipe diameter to 900mm, although we have kept the model with 600mm pipes for sensitivity analysis.
4. Parallel pipes are merged, following the approach set out by Lenz[7], to determine the diameter of the resulting merged pipe. This reduces the number of pipes in the model, helping to guarantee the model is numerically stable and tractable. It also aligns with our understanding that the PU network should be radial and not include cycles.
5. Finally, pipes in series with similar diameters were also merged together, again, with the goal of obtaining the smallest possible number of pipes for numerical tractability.

[5] Project Union, National Gas, 2025
[6] Network Route Maps, National Gas, 2025
[7] Lenz, R., 2025. Pipe merging for transient gas network optimization problems. *Applied Mathematical Modelling*, *137*, p.115660 “Pipe merging for transient gas network optimization problems”, R. Lenz,

The locations of the compressor stations were manually selected out of the compressor stations currently used by NGT that lie close to the future PU network. All compressors were assumed to be bi-directional.

The resulting pipeline model is shown in Figure 3, with the colour indicating the diameter of the pipe and the thickness of the line representing its volume.

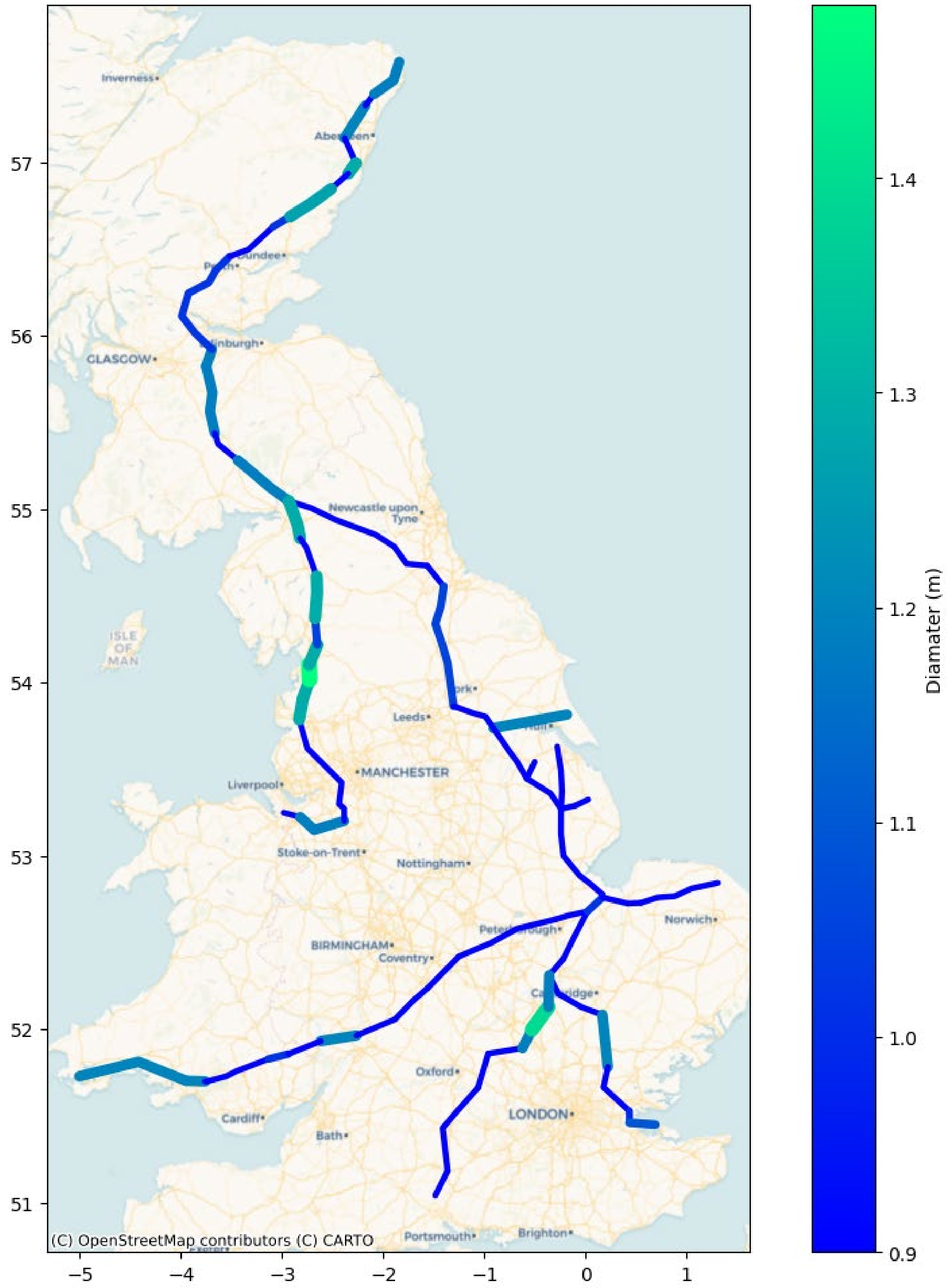

Figure 3 Gas pipeline model. Selected compressor station locations: Aberdeen, Avonbridge, Bishop Auckland, Carnforth, Nether Kellet, Felindre, Churchover, Peterborough, Hatton, Lockerley, Aylesbury, Kirriemuir, Kings Lynn, Wisbech, Cambridge, Huntingdon.

Electricity network

The electricity network is produced from the ETYS from 2024, with specific assumptions and minor amendments made based on discussion between TNEI and NGET.

For the model, we have used the 2035 version of the network, which includes many of the planned strategic network investments in RIIO-T3 and beyond, such as the offshore HVDC Eastern Green Links and Western Link 2. The resulting network is shown in Figure 4, alongside some of the key system boundaries included in the ETYS publication. Note that circuits are plotted as the crow flies rather than following actual routes and, as a result.

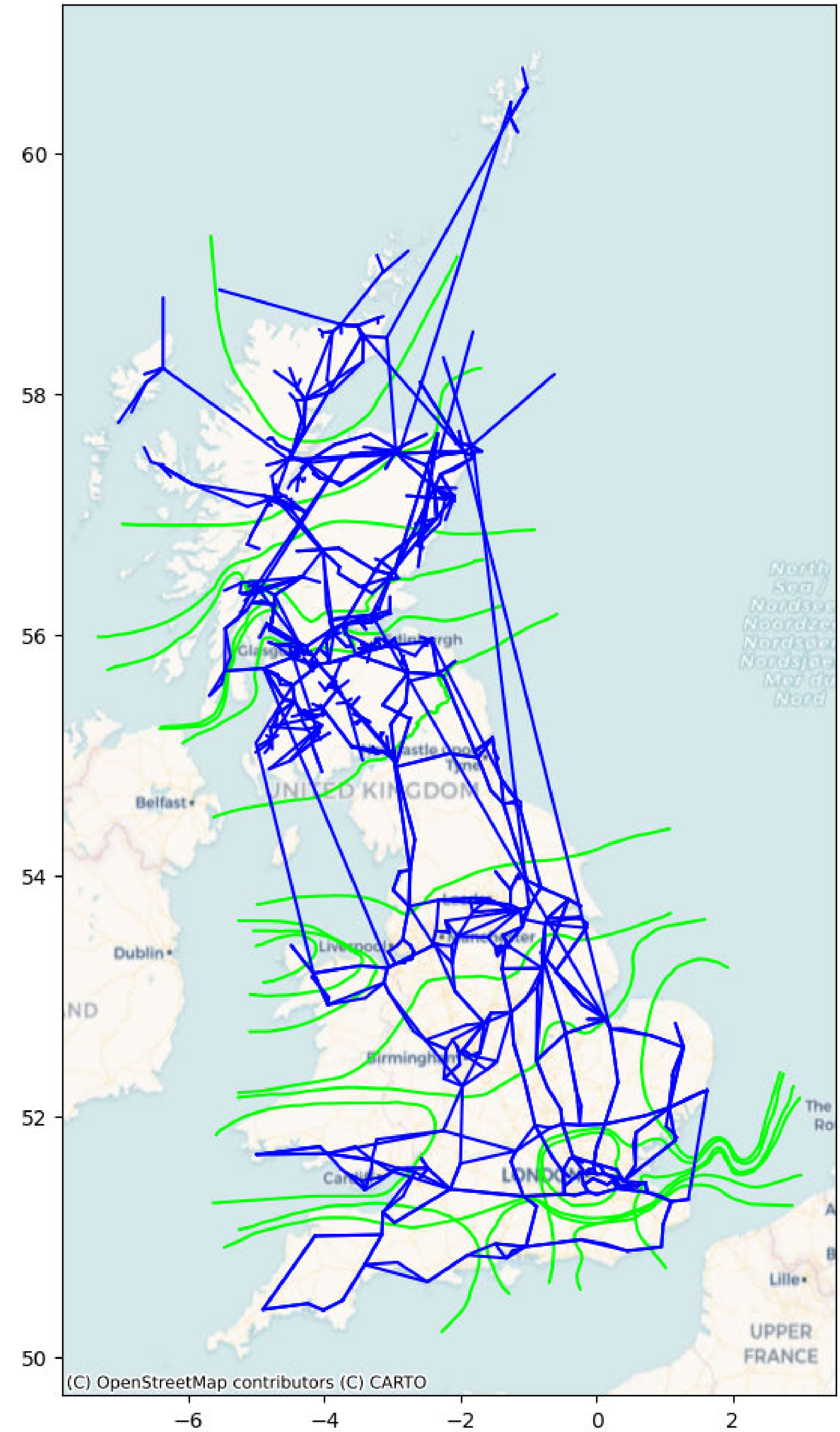

Figure 4 Electricity transmission system model

To ensure tractability, an aggregated version of the model was also produced. All nodes in the network were mapped to their major and minor FLOP[8] zones, and a mapping also produced between boundaries and flop zones. Figure 5 shows these aggregations of FLOP zones between boundaries, based on Grid Supply Point (GSP) GIS information published by NESO[9] .

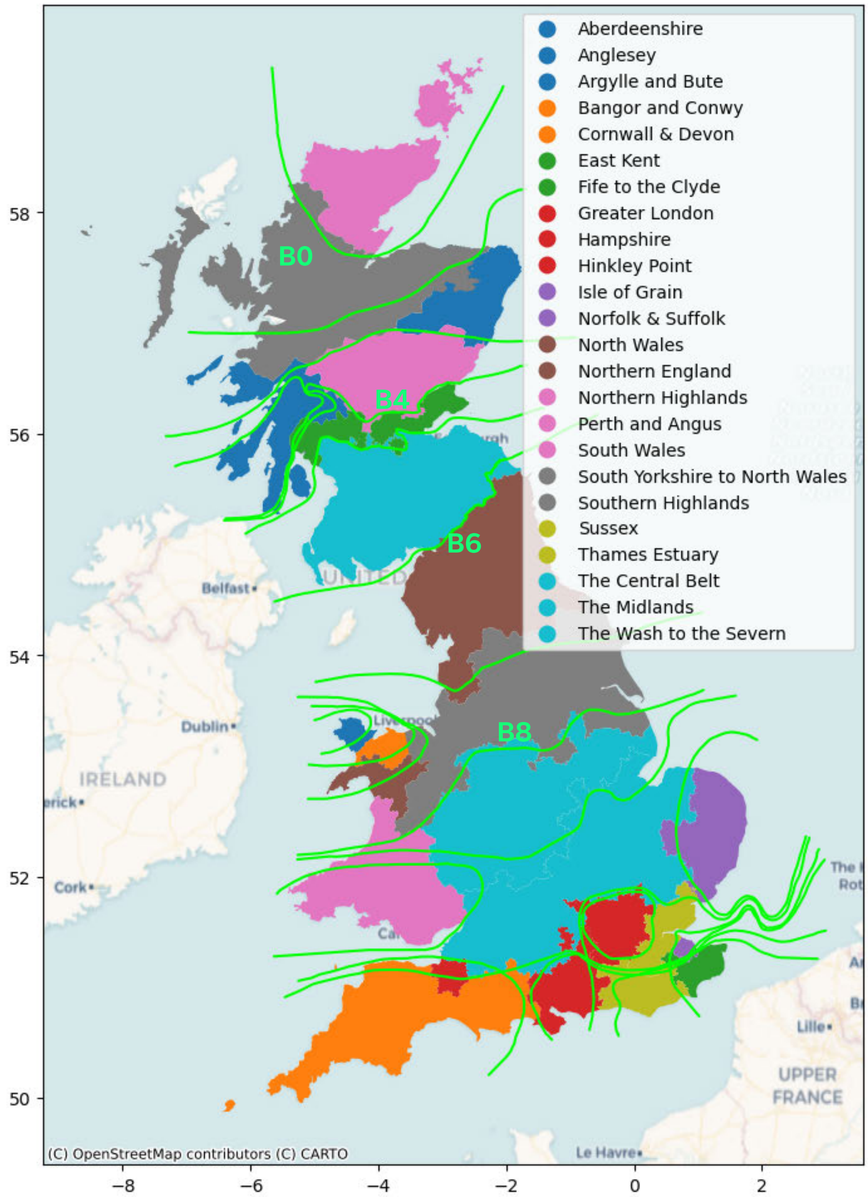

Figure 5 Aggregated FLOP zones between transmission system boundaries

The aggregation allows for some major and zones to be represented in detail, while others are represented as a single node with no restrictions within the zone. Aggregated zones have all their nodes merged together, and all branches within the zones are removed. Real power balance is informed at each aggregate node, but the power flow equations on aggregated lines are not enforced. Nevertheless, realistic flows are ensured through boundary capacity limits, which are sourced from ETYS, using projected values for 2045.

The electricity network used in this report includes a detailed representation of Aberdeenshire and Perth & Angus in Scotland, and the East Coast of England (within Northern England and South

[8] Flow Optimisation
[9] GIS Boundaries for GB Grid Supply Points, NESO, 2025

Yorkshire). The rest of the electricity network is aggregated into zones and boundaries. The resulting aggregated network is shown in red in Figure 6.

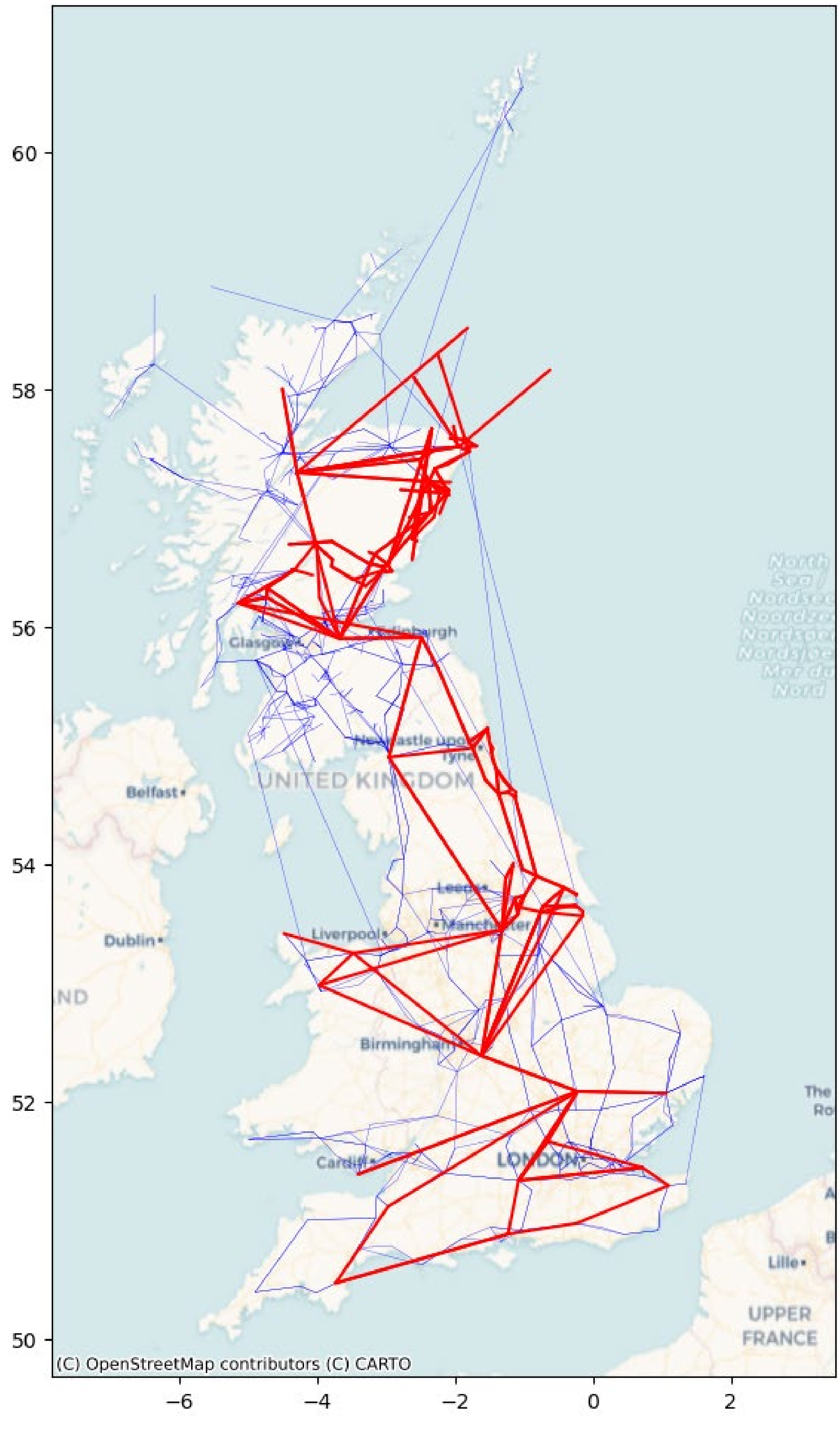

Figure 6 Electricity system model for Alpha

Future Scenarios

The analysis presented in this report is based on the 2025 Holistic Transition scenario for the future year 2045. The core features of this scenario from 2030 through to 2035 have informed the UK Government's Clean Power plans[10].

In this scenario, hydrogen is used for industrial applications, aviation and shipping demand (which are otherwise hard to decarbonise sectors), with very little hydrogen used directly for heating. Hydrogen is produced by either steam methane reformation (SMR) or electrolysis and is also used as a source for power generation. The Sankey diagram in Figure 6 summarises this scenario at a high-level, although note that this describes the year 2050 (but is nevertheless similar to 2045).

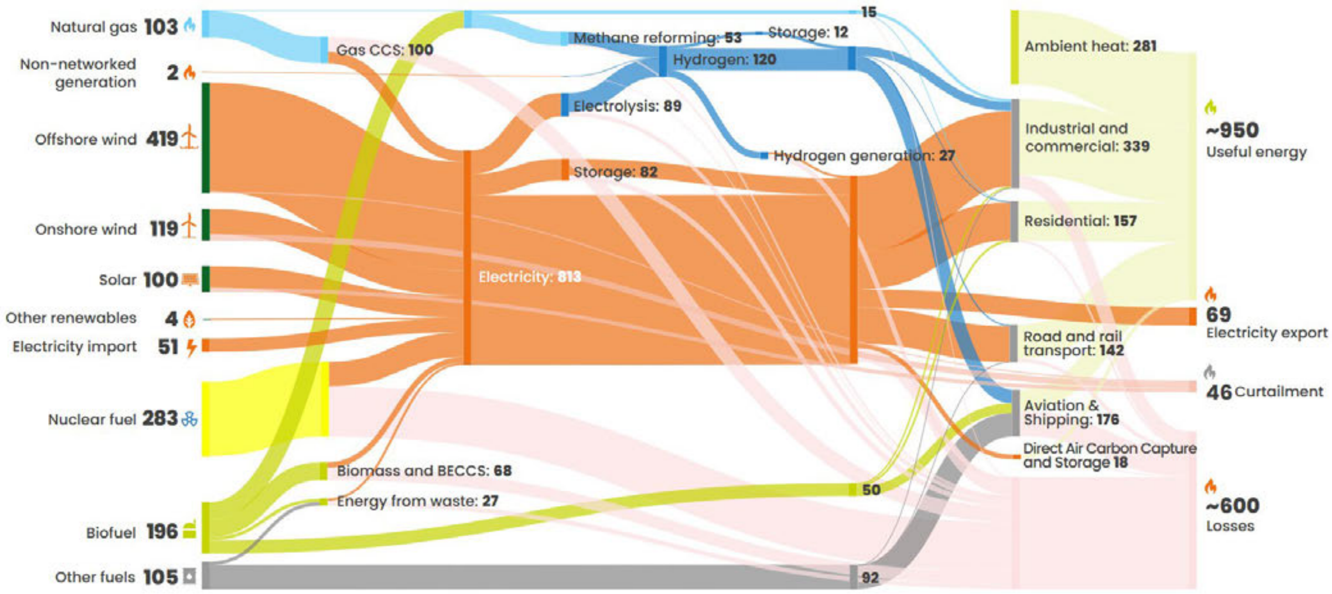

Figure 7 Sankey diagram for Holistic Transition scenario

Generation capacity

Generation capacity is based on the information published in various FES documents, supplemented with additional assumptions where necessary. The FES building blocks data, within the FES data workbook, includes capacities of each type of generation, aggregated by GSP (for distributed generation) and by TO licence area (for transmission connected generation). For distributed generation, these capacities are provided directly to the model.

However, for transmission connected generation, further spatial disaggregation is necessary, to map this generation capacity to specific nodes (or, at least, to major and/or minor FLOP zones). This has been done by combining the aggregate (TO level) capacities in the FES with planned connections detailed in the Transmission Entry Capacity (TEC) register[11].

Wind, Solar, and BESS

Wind, Solar and BESS projects were filtered down to match the capacities included within the FES scenario based on the principles of the Gate 2 to Whole Queue process within Connections Reform (i.e. whether projects have planning permission and their connection dates).

[10] Clean Power Action Plan, UK Government, 2025
[11] TEC Register, NESO, extracted December 2025

Pumped storage and biomass

For future pumped storage, and biomass, it has been possible to almost exactly identify which specific projects have been included in the FES, based on the total project capacities and the TEC held.

Interconnectors

Future interconnectors were prioritised for inclusion in the model based on their connection date, with the earliest connecting projects in each Transmission Operator (TO) licence area included until the total capacity approximately matched the capacity within the FES.

Nuclear

We have assumed the planned nuclear power stations at Hinkley Point and Sizewell will progress, as well as another project at Bradwell. The remaining nuclear capacity is assumed to be split between Small Modular Reactor developments at Wylfa and Oldbury.

Gas and hydrogen generation

There is a significant pipeline of new, large gas generation within the TEC register. We have made assumptions about which projects will progress as hydrogen, and which as natural gas with Carbon Capture and Storage, with a preference for hydrogen projects to be closer to the Project Union network. We have made an assumption about which projects are connected to the hydrogen network, and which are supplied from local hydrogen systems, based on the distance from each generator and the Project Union network and the installed capacity of the generators, with smaller and more distant generators assumed to not be connected to the national hydrogen system.

Electricity demand

Electricity demand at each Grid Supply Point (GSP) is based on the FES regional workbook, which gives peak electricity demand from different technologies at each GSP. This includes distribution and transmission connected electrolysis capacity. Like with hydrogen generators, we have made an assumption that smaller and more distance electrolysers are not connected to the national hydrogen system.

Other hydrogen users

In addition to hydrogen power stations and electrolysers, we have also included other forms of hydrogen injection and withdrawal, representing the production of hydrogen from Steam Methane Reformation (SMR), consumption for industrial demand, and storage within salt caverns.

The Holistic Transition FES includes 35.29 TWh of SMR supply in 2045. We have assumed this hydrogen would be produced at the existing North Sea and European interconnector terminals at St Fergus, Teesside, Easington and Bacton. For simplicity, we have translated this into a constant production of 1 GWh per hour at each site[12].

The FES also includes 72.19 TWh of hydrogen demand for all purposes other than power generation. We have assumed that 25% this is off the gas grid within local / regional hydrogen

[12] From FES, we understand that NESO assumes these facilities operate at a fairly constant level.

systems, consistent with our assumption about off-grid electrolysis, resulting in an average hourly demand of 6 GWh. This is shared evenly across the six industrial clusters indicated in National Gas's Project Union maps, at Grangemouth, Teesside, Merseyside, the Humber, Milford Haven, and Southampton.

We have included salt cavern storage injection points in Merseyside and in Teesside, based on existing analysis of the potential resource[13]. These locations function as unrestricted sources of extra gas injection or withdrawal to help balance the network.

[redacted]

[redacted]

[redacted]

[13]See, for example, Williams et al., "Does the United Kingdom have sufficient geological storage capacity to support a hydrogen economy? Estimating the salt cavern storage potential of bedded halite formations", Journal of Energy Storage, 2022

Daily profiles

The model is run for individual days at a time, at an hourly granularity. Time-series data is required to describe how electricity demand and renewable availability varies from one time step to the next. We have considered 4 specific types of operational day, which show variation across two different dimensions:

- The overall level of electricity demand
- How renewable availability changes through the day (e.g., windy to calm or calm to windy).

Zonal wind and solar load factors (based on actual historical BMU data from Elexon[14] and the PV Live[15] solar data), defined as percentages of installed capacity, have been used from four real days in the 2024 calendar year, to define four different scenarios:

1. **Winter Windy to Calm:** January 24th 2024 provides an example of wind output starting very high and getting low on a high demand day
2. **Winter Calm to Windy:** January 25th 2024 provides an example of wind output starting low and getting very high on a high demand day
3. **Summer Windy to Calm:** July 5th 2024 provides an example of wind output starting very high and getting low on a low demand day
4. **Summer Calm to Windy:** July 3rd 2024 provides an example of wind output starting low and getting very high on a low demand day

For each of these days, a scaled demand profile (for baseline residential, commercial, and industrial demand) has been produced based on NESO demand data, adjusted to offset the impacts of embedded wind and PV generation. EV and heat pump profiles are included based on datasets from previous innovation projects[16]. Assumptions are included about the ability for load to be shifted within the day, based on some of the findings included within the FES, with particularly high levels of shifting from commercial demand and electric vehicles. However, demand can only be shifted within the day; it cannot be shifted from one day to the next, or reduced entirely.

Nuclear power stations and biomass are assumed to operate as base load, with a constant power output equal to half their capacity (to reflect a pessimistic maintenance scenario). Flows on interconnectors are assumed, and fixed, with a general rule that they export when it is very windy and import when wind output is lower.

Figure 9 shows the resulting levels of demand, fixed power output (for baseload and interconnectors), and available power (for renewables) for the Winter Windy to Calm scenario.

[14] Actual Generation Output Per Generation Unit (B1610), Elexon, 2025
[15] PV Live, Sheffield Solar, 2025
[16] Electric Nation Data, NGED, 2019 and BEIS Electrification of heat demonstration project, 2025

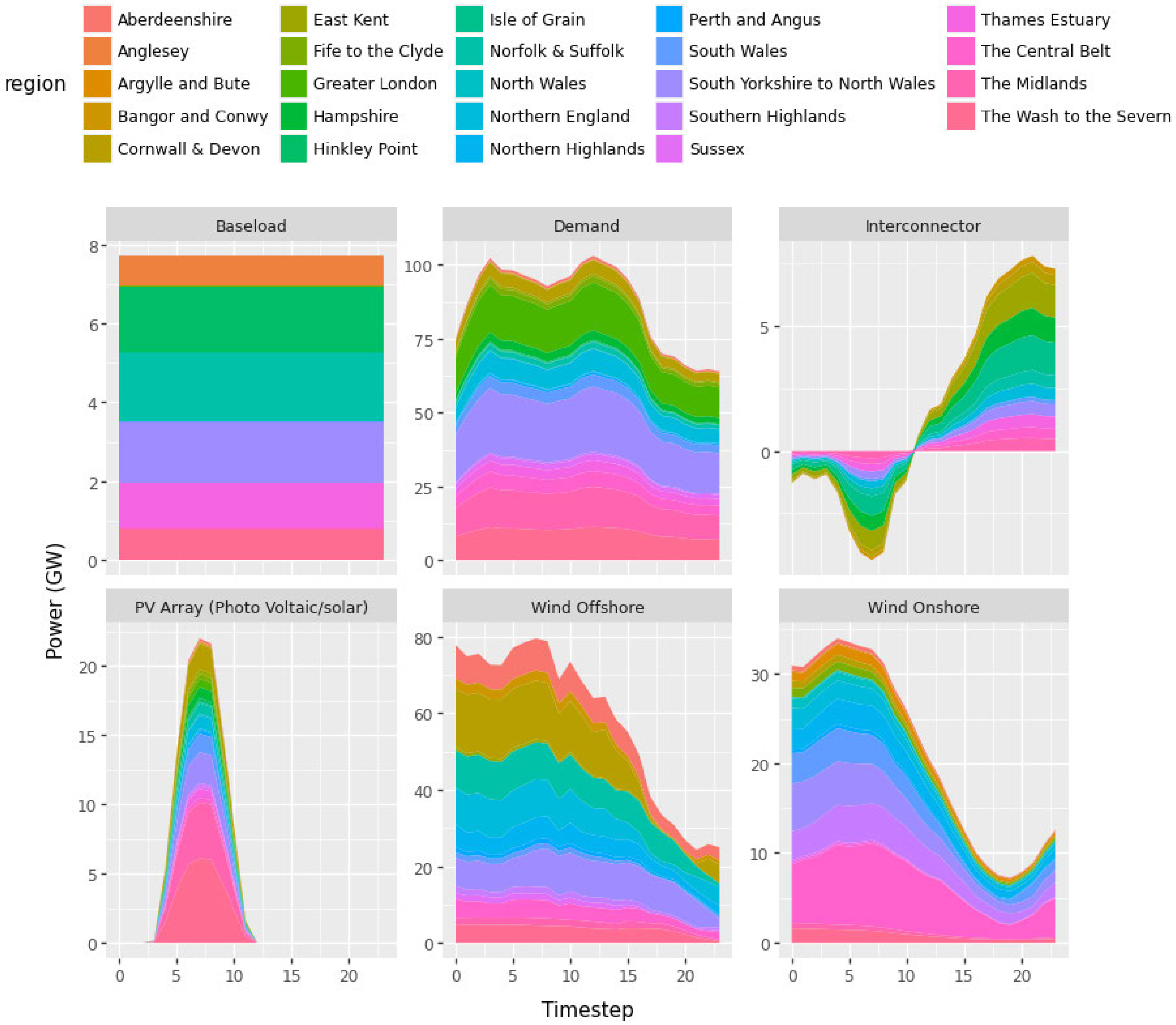

Figure 9 Hourly inputs for the Winter "Windy-Calm" Scenario for half hourly timesteps

Cost assumptions

While the model is not concerned with costs as a key output, relative costs of different types of electricity generation and demand are used to drive decision-making. Figure 10 summarises the different levels of cost (and credit i.e. negative cost, in green) used to drive decision making in the model. The absolute level of these costs is not important, as long as its drives realistic decision-making processes.

The model assumes that all renewable generation (whether transmission or distribution connected) can be curtailed, but that this incurs a penalty based on the most recent DESNZ estimates[17] of the levelised cost of energy for that particular technology in 2045. For thermal generation, we have used these variable O&M rates, carbon costs, fuel costs, and efficiencies.

[17] Electricity generation costs 2025, UK Government, 2025

We have assumed a baseline value of stored hydrogen of £25/ MWh[18], and explored this through sensitivities. This sets the production costs for hydrogen generation (via the assumed efficiencies), as well as the value created when hydrogen is electrolysed. For simplicity, we assume that value is created as soon as hydrogen is electrolysed, and cost is incurred as soon as it is consumed, meaning hydrogen stored in salt caverns and in the network's linepack are considered to have the same value. A price of£25/MWh ensure that (i) electrolysis is not valuable enough to justify running any non-renewable power station, but (ii) CCHTs would be preferred to CCGTs.

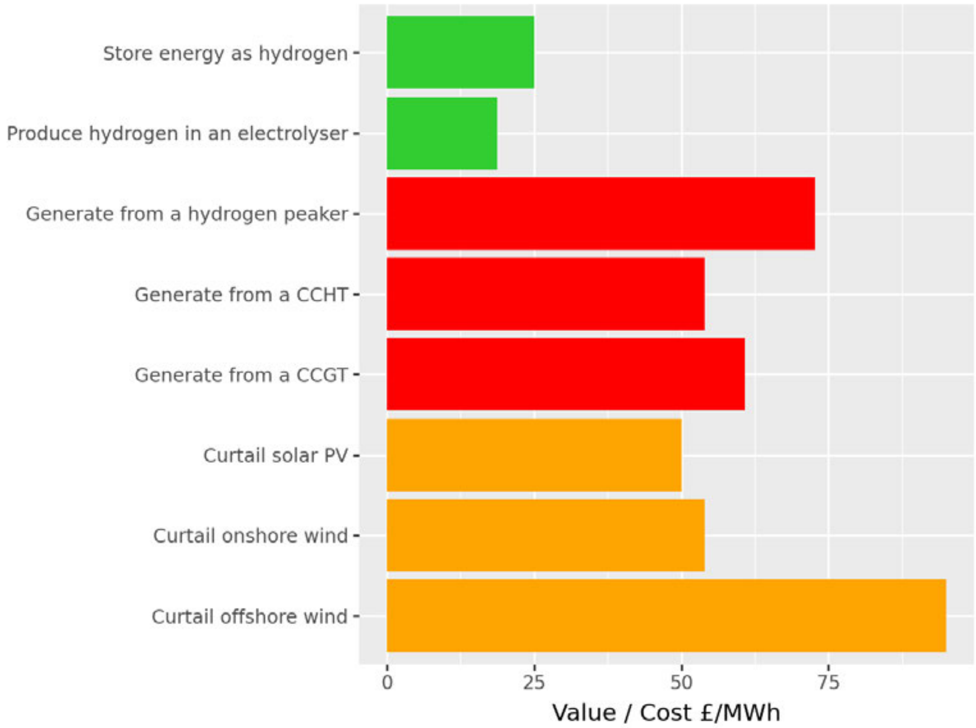

Figure 10 Levels of cost driving decision making in the Alpha model

At a high level, these costs and values lead to the following behaviours:

- The output of renewable electricity is maximised wherever possible, in order to avoid the costs of curtailment.
- Interconnectors are assumed to export when it is very windy and import when the wind dies down.
- Electricity storage (batteries and pumped hydro) can cycle to help balance demand with renewables within the day, although we constrain these to a single cycle within a day.
- Flexible demand can also help to minimise the volume of curtailment.
- If possible, curtailment will be avoided through electrolysis of hydrogen.
- However, no other types of generation are dispatched in order to fuel electrolysers; their dispatch costs are higher than the value created from the electrolysis.
- Where thermal generation is required (after baseload, interconnection, demand flexibility, and electricity storage have been exhausted), large scale hydrogen generation is favoured.

[18] In reality, the value of hydrogen would be determined as part of the medium-to-long term planning process represented by the seasonal energy demand layer in Figure 1.

Operational restrictions

In addition to the physical models of the gas and electricity systems, additional operational restrictions are imposed which limit how the system can be operated.

Forecasts and foresight

We assume that the system operators have perfect foresight of system conditions throughout the day.

Boundary and circuit limits

The total electricity that flows between aggregated zones is limited by the capacity of the boundary between those zones. Where circuits are modelled in detail, the flow on each circuit is limited by its pre-fault rating, scaled by 50%. to approximate the impact of N-1 security criteria.

Penetration of renewable generation

We assume that, in any specific hourly period, renewable energy can provide at most 90% of electricity demand (including electrolysers but not including interconnector exports or charging of electricity storage).

Electricity system operability

Conversely, we assume that at least 10% of demand must be supplied by transmission connected synchronous generation, including nuclear, biomass, CCGT and CCHT. These are assumed to be required to provide system services like inertia, fault level, and reserve. This is a strong assumption, and its impact has been explored in a sensitivity.

Electricity storage cycling

We allow the model to decide the initial state of charge of electricity storage, which represents an ability to plan days-ahead for system conditions. However, we impose that the total electrical energy in storage at the end of the day must match the total electrical energy in storage at the end of the day, such that electrical storage is only used for within day balancing.

Daily change in linepack

Similarly, we allow the initial level of hydrogen energy stored within the network's linepack to be optimised by the model. However, we impose that the daily change in the total linepack is constrained. We limit this to 30 GWh, based on the existing target within NGT's Linepack Performance Measure of a daily change of 2.8mcm. Due to the generally lower linepack within the Project Union network (due to the lower length of pipe and the reduced energy density of hydrogen), a 30 GWh change in linepack is relatively much more significant than within the existing NTS, corresponding to a 10% change (rather than a ~1% change in the methane NTS).

Pressure limits

We impose minimum and maximum pressure limits of 40 bar and 94 bar respectively.

Exploration of Use Cases

Figure 11 shows the modelling work flow we have adopted within the project.

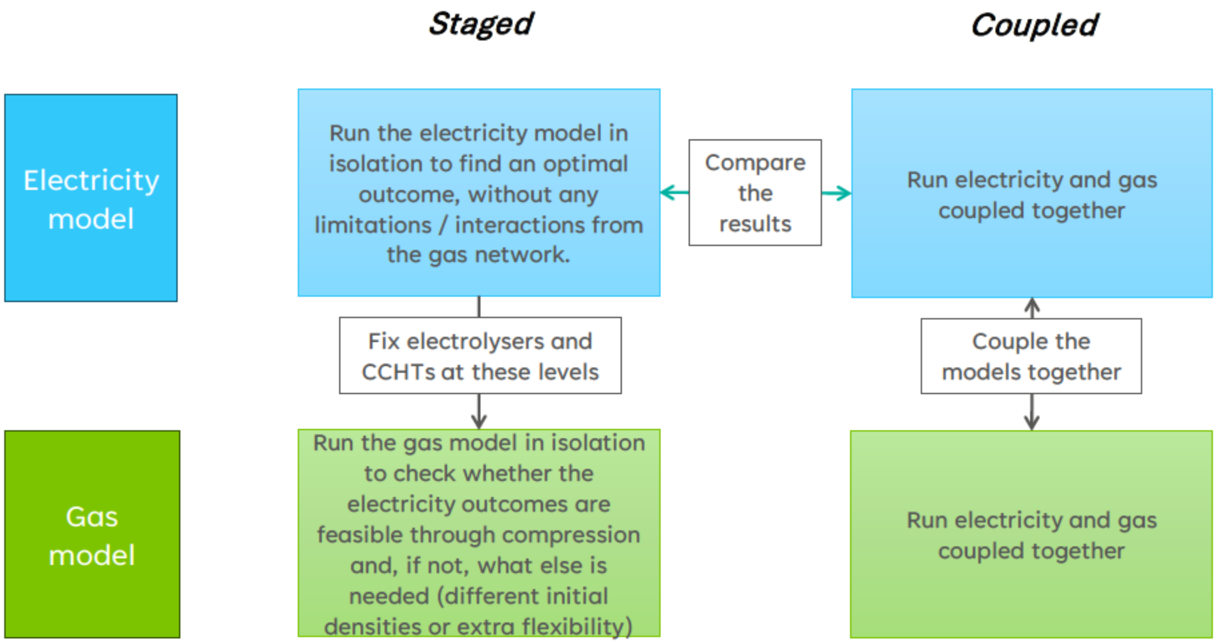

Figure 11 Alpha modelling workflow

As the figure shows, we run the model in two different methods: staged and coupled. In the staged run, injections into and withdrawals from the hydrogen network for electrolysers and hydrogen generators are fixed at the levels set by the electricity system in isolation. In many cases, the required gas flows would not be physically feasible, and so we allow for “slack” injections and withdrawals of hydrogen, which we describe as residual balancing, the volume of which is minimised.

In the coupled case, the electricity and gas models are solved at the same time. The costs of these residual balancing actions are set very high such that the model will try to avoid using them, and instead change the behaviour of the electricity system and the technologies which couple the networks together.

The full model is run in hourly timesteps over the course of each day. The three components combine to create one large mathematical optimisation problem in Pyomo, which is solved using the non-linear optimisation solver, IPOPT.

Chapter 4: Model Results

This section presents results from the models, and discussion of what the results could mean for the planning and operation of integrated energy systems.

Staged model

First, we present results from the staged model, in which the electricity system is modelled, with fixed requirements then passed to the gas system.

Electricity system

Generation mix

The generation mix is shown in Figure 12 below, separating out renewable technologies and baseload in one set of plots and all other generation types in another.

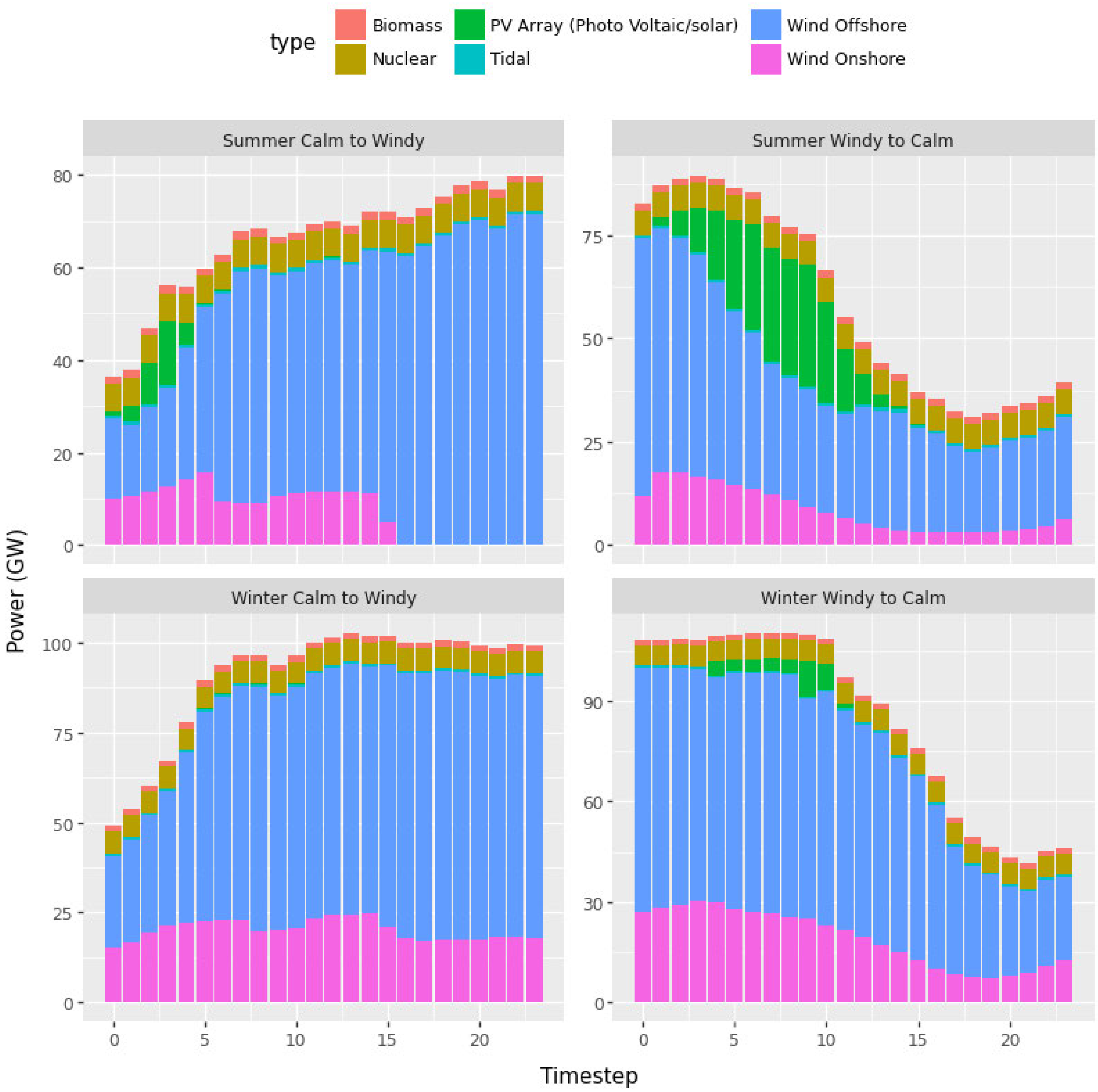

Figure 12 Generation mix for renewables and baseload across all days in the "staged" run

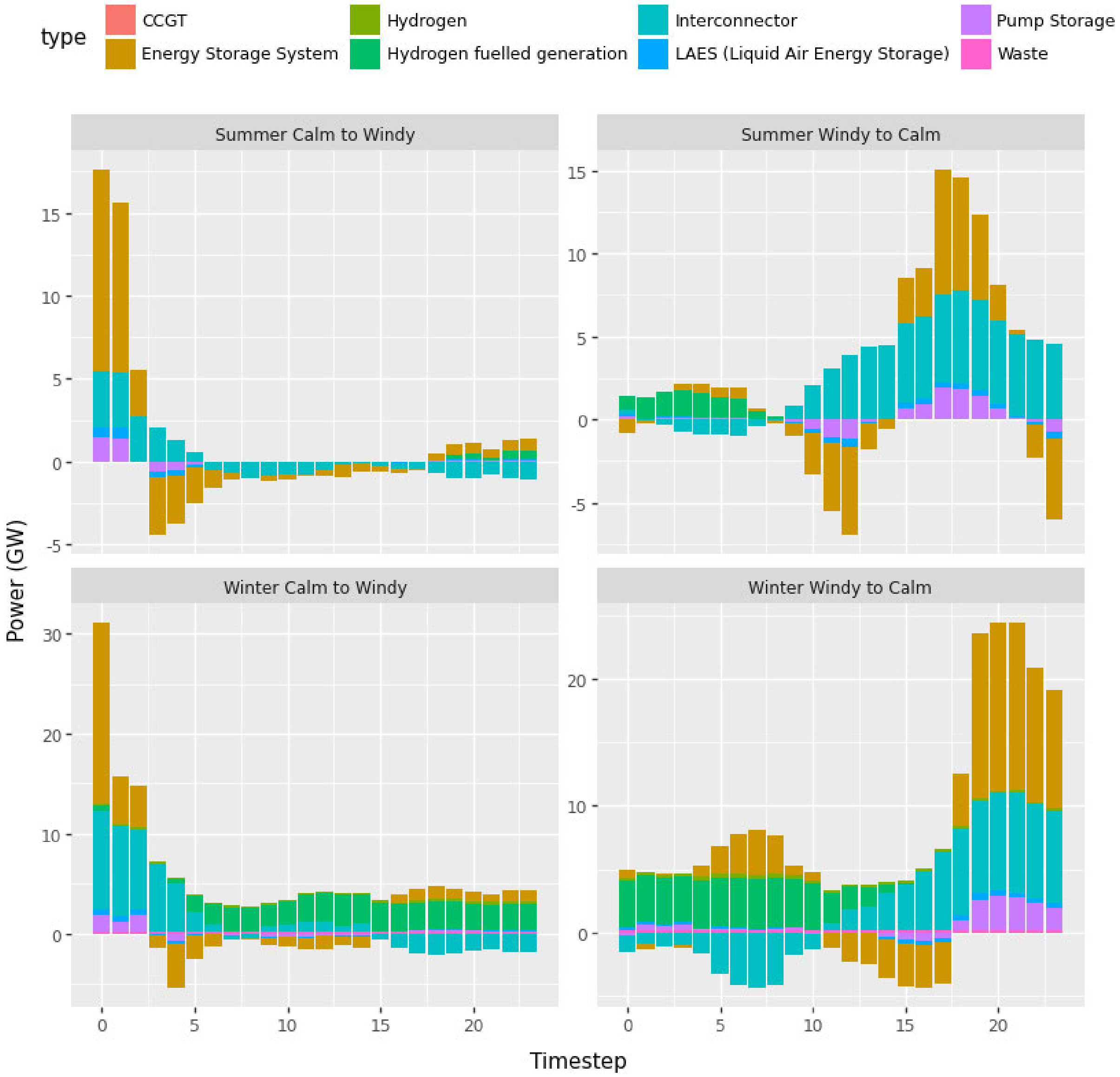

Figure 13 Generation mix for interconnectors and dispatchable power across all days in the "staged" run

The very high volumes of renewable power output are notable, as is the preference for the model to generate from offshore wind (as it has the most expensive curtailment cost).

The use of other types of generation is much more varied. In summer, significant volumes of storage are required during calm periods but, when combined with the interconnection, not much additional generation is required. In winter, hydrogen fuelled generation (CCHT) issued extensively, although, interestingly, there is greater usage during periods where renewable output is high due to the assumed need for thermal generation to support system operation. This is somewhat counterintuitive, as it means the electricity system is producing hydrogen in some locations (to use excess renewables) and consuming it in others (to support system operation). It is not clear whether this is an unrealistic consequence of how the model is set up or a possible feature of how this type of energy system might operate. However, this is not strictly important for the purposes of this report; it is more interesting to examine cases where hydrogen needs to be moved around the system, even if this is a slightly unusual use case.

Hydrogen fuelled generation is not dispatched during the "calm" periods in winter; since the calmest periods modelled occur either at the start or the end of the day, these do not coincide with the demand peaks. Furthermore, calm does not mean there is no renewable generation, and even in the calmest periods modelled during the winter days there are still tens of GW of renewable output.

Boundary flows

Next, we show the transfer of power and energy across four key system boundaries, B0 (the northernmost part of the Highlands), B4 (which separates SSEN-T's licence area from SPT's), B6 (on the Scotland and England border) and B8 (which separates the north of England from the midlands. In every case, a positive number represents a flow of power from North to South. (The boundaries are illustrated on Figure 5.)

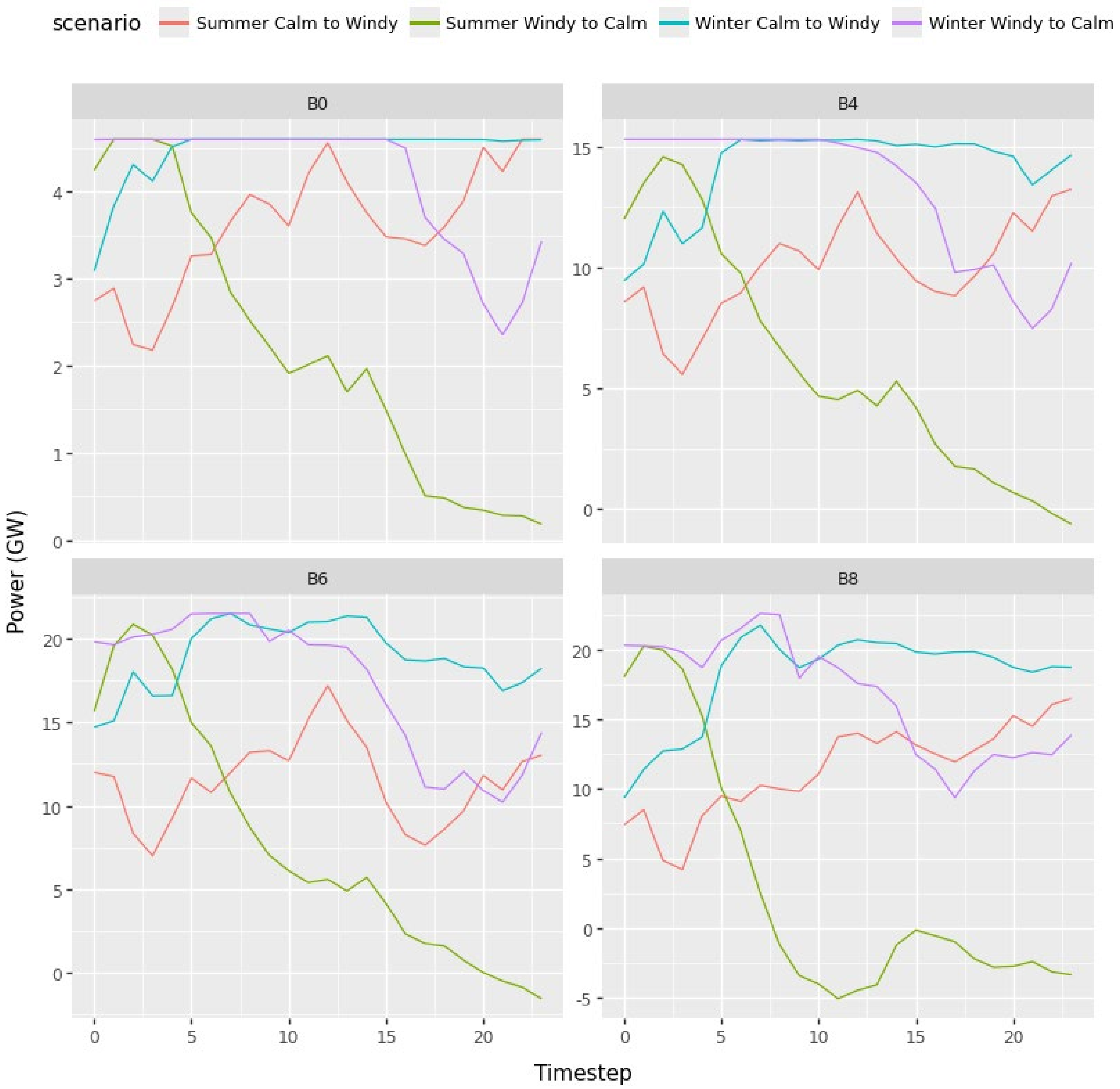

Figure 14 Boundary flows

The Scottish boundaries are regularly at, or close to, their maximum capacity, particularly when it is windy, so that renewable power can be exported south.

Renewable curtailment

The next plot shows the amount of renewable energy of different types being curtailed. As described above, the model's preference for curtailing solar and then onshore wind before offshore wind is clear. Curtailment is highest when it is most windy, or during the summer in the middle of the afternoon when solar output is highest.

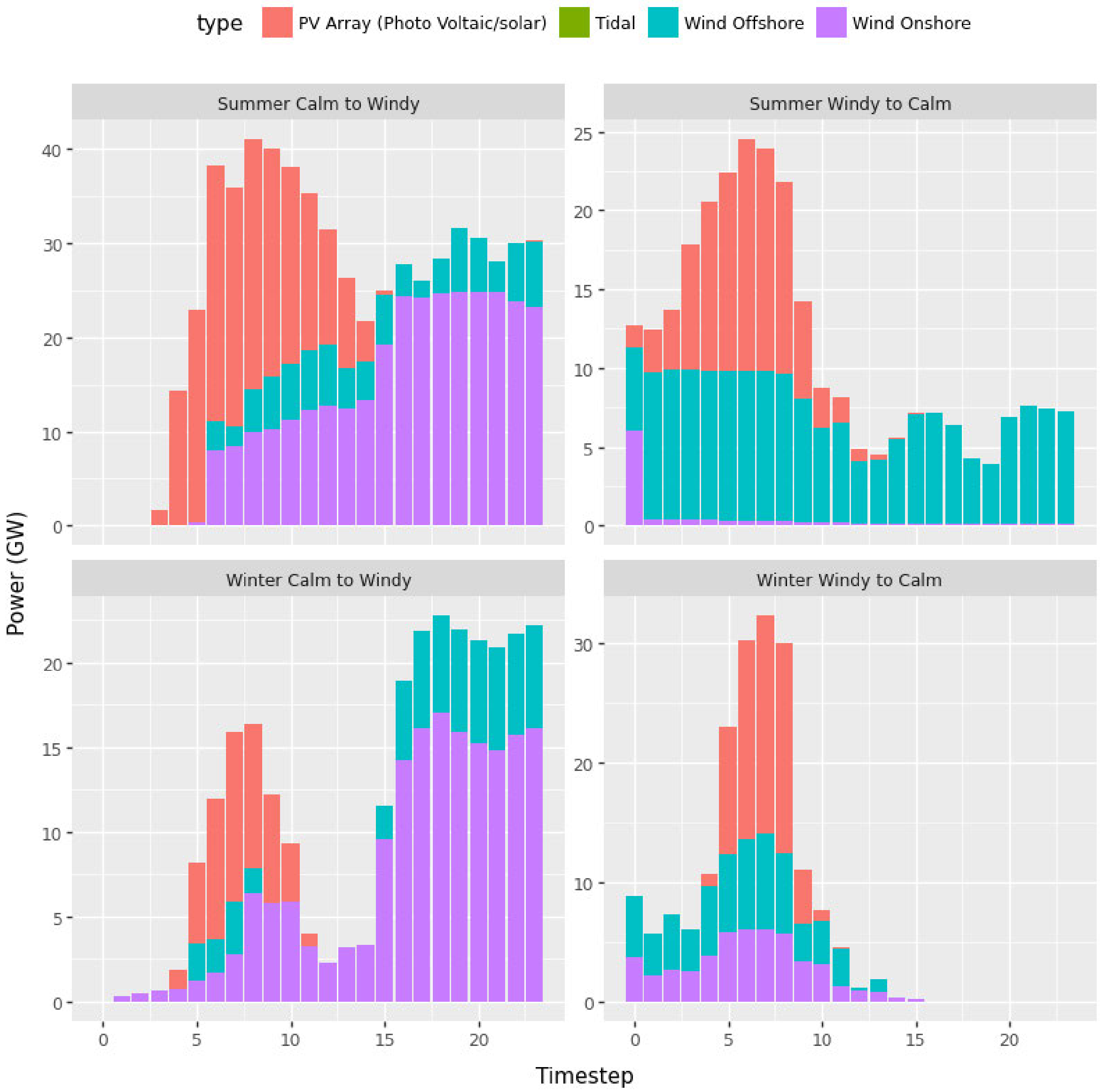

Figure 15 Renewable energy curtailment

Figure 16 shows the spatial distribution of the total volume of curtailed renewable energy for the Winter Windy to Calm day (with the colour legend in GWh).

Renewable curtailment is high in the North of Scotland, where curtailing wind can affect multiple boundaries. However, it is also vary in the Southwest of England. The TEC register includes many offshore wind projects connecting in this region, but ETYS suggests only a few GW increase in boundary capacity. There are also relatively few electrolysers modelled in this region (and none connected to the PU network, due to the long distances), meaning little opportunity to absorb excess generation into the hydrogen network. This is likely an area where our simple assumptions about generation locations are misaligned with the detail that underpins FES (and hence the ETYS).

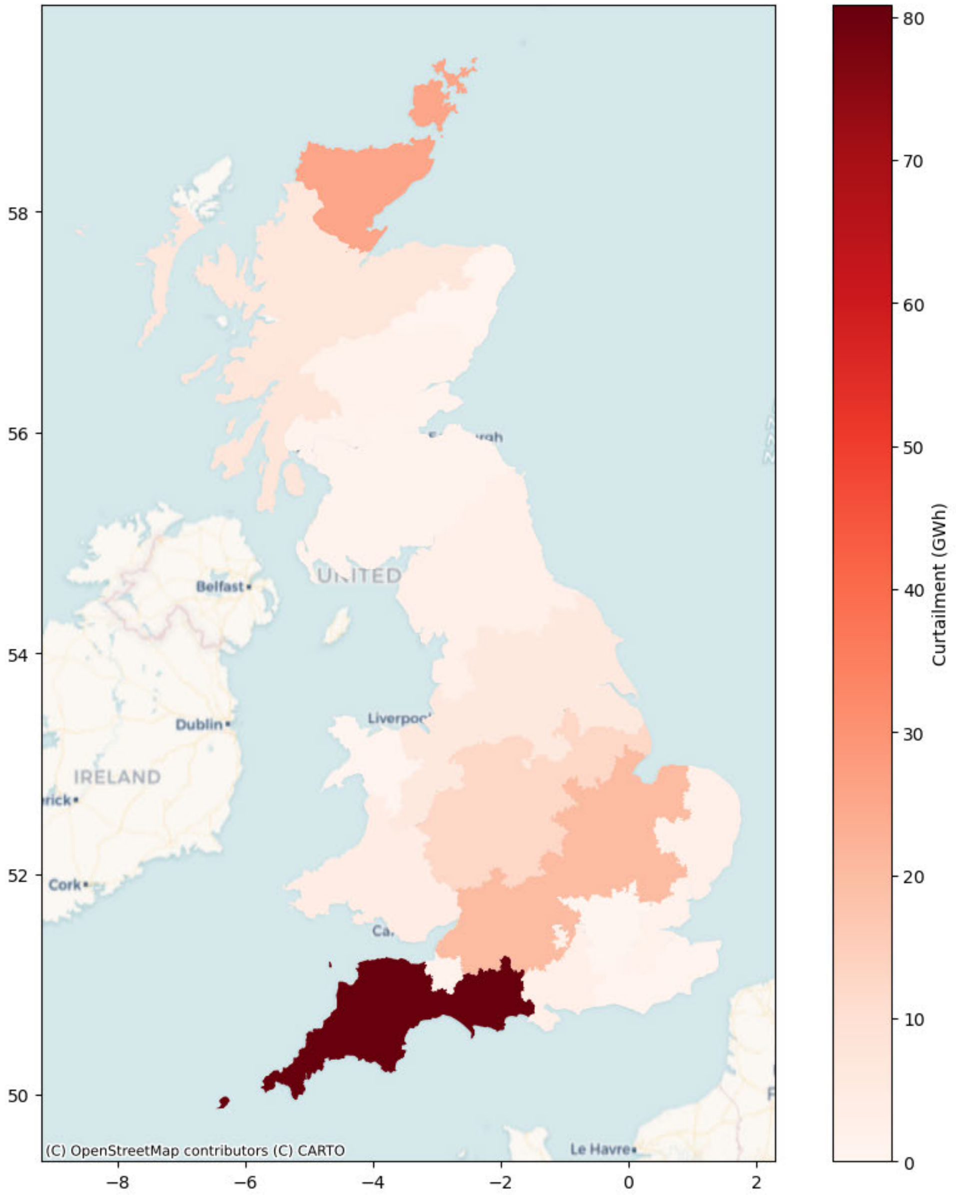

Figure 16 Spatial distribution of renewable curtailment

Hydrogen power generation

Figure 17 shows the spatial distribution of hydrogen power generation connected to the PU network. The overwhelming majority of this generation takes place in the Northeast of England and Merseyside, although the generation we have located in Aberdeenshire and the Central Belt is dispatched at times. As describe above, this generation tends to run when wind speeds are high in order to support system operability, as demand is not high enough / renewable output is not low enough to require it just to meet demand.

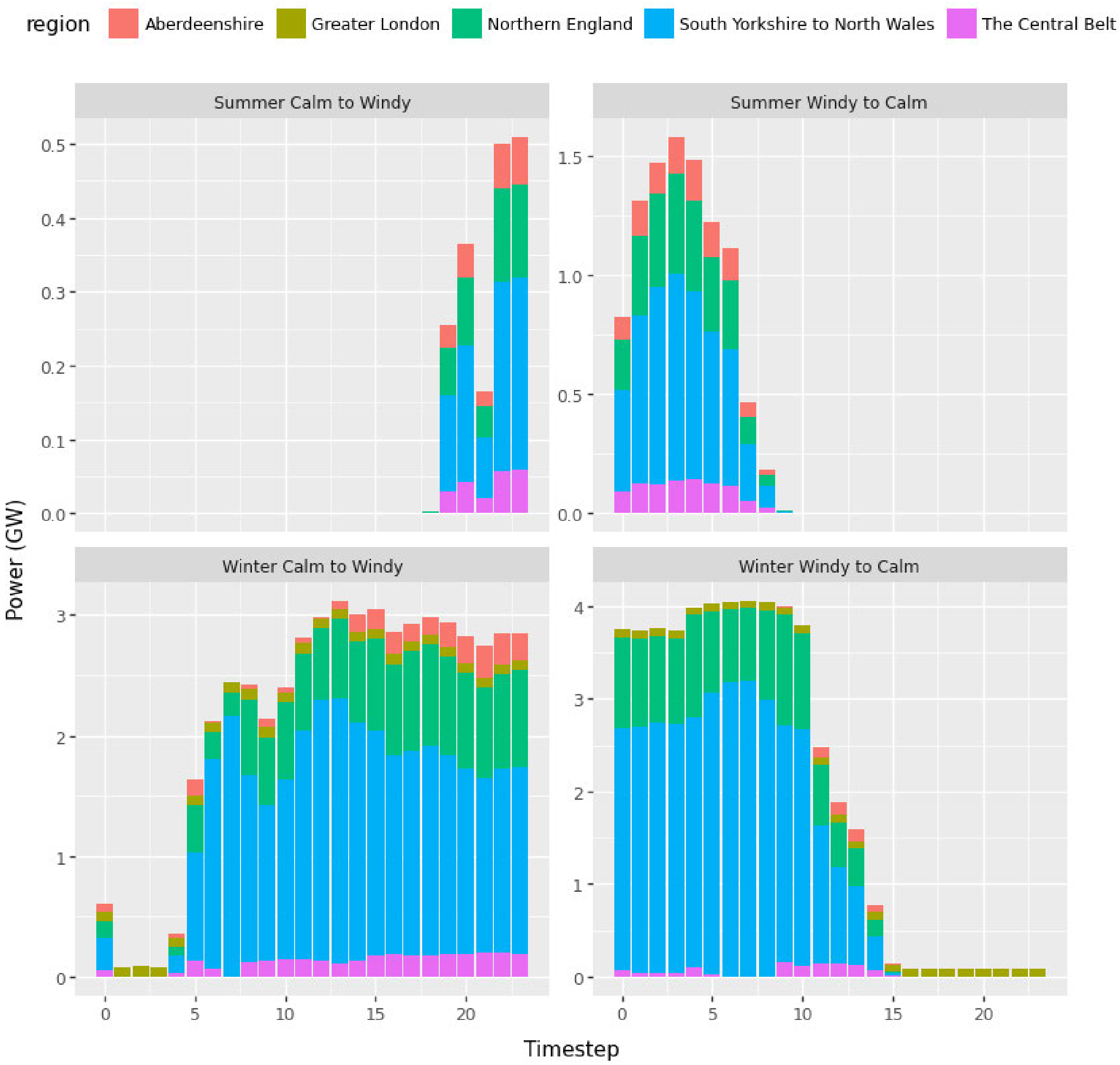

Figure 17 Spatial distribution of hydrogen generation connected to the network

Electrolysis

Finally, Figure 18 shows the electrical demand for electrolysis across different regions (note the colour scale has changed compared to the previous plot). Electrolysis load is fairly constant whenever there is excess renewable energy. This is almost 24/7 on both the calm days, even in winter when demand is high. The sudden drop in electrolysis demand in the second timestep (6am) on the Summer Calm to Windy day is due to a temporary spike in electricity demand at this timestep.

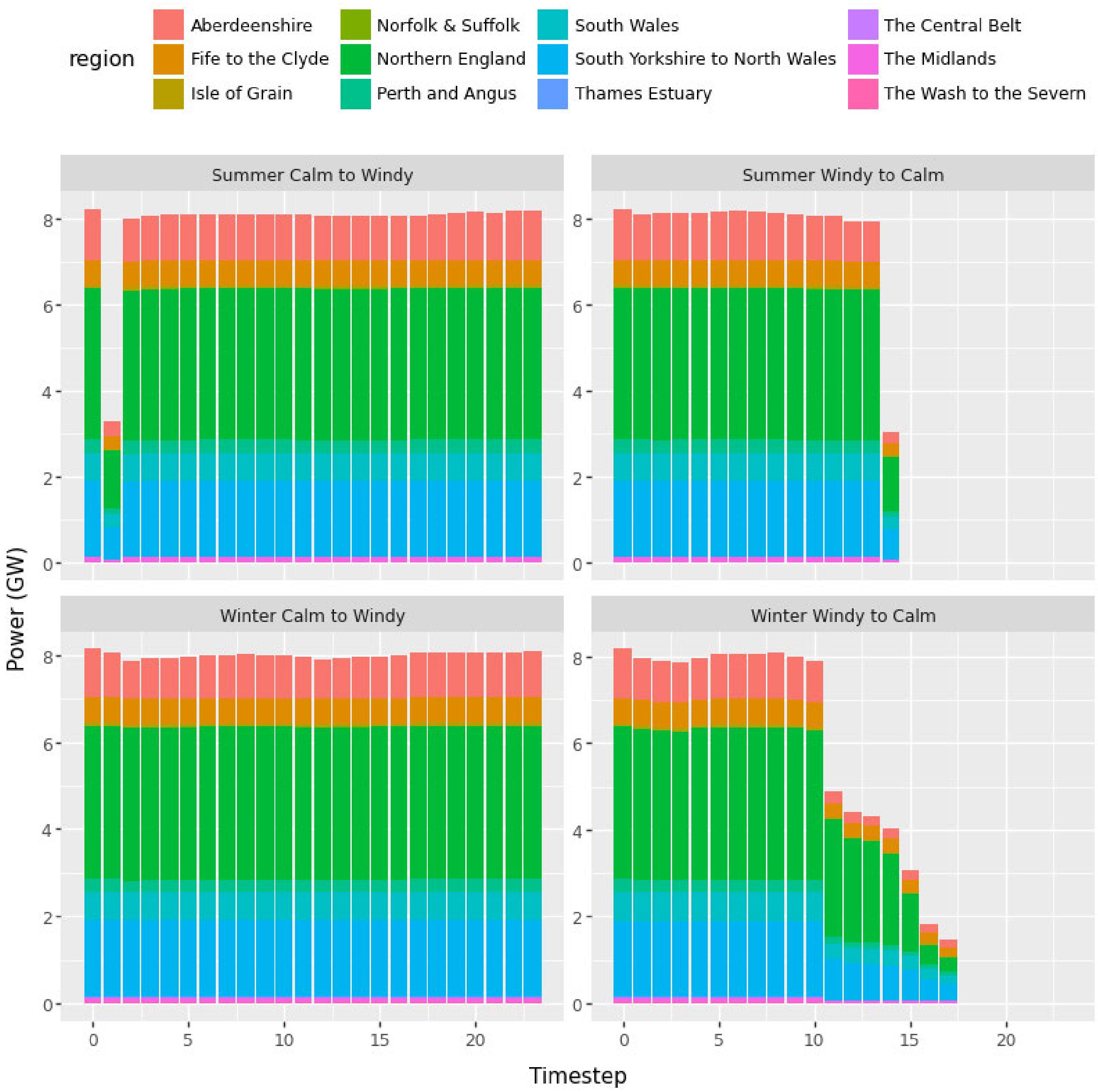

Figure 18 Regional electricity demand for electrolysis

Gas system

Balancing shortfall

The key output for the gas system in the staged model run is whether the requirements of the electricity system are feasible. This is measured by examining the size of the hydrogen balancing shortfall; the extra volumes of hydrogen that would need to be withdrawn or injected throughout the system so that flows and pressures could be sustained. The hourly shortfalls are shown in Figure 19, colour coded by the approximate location within the Project Union network.

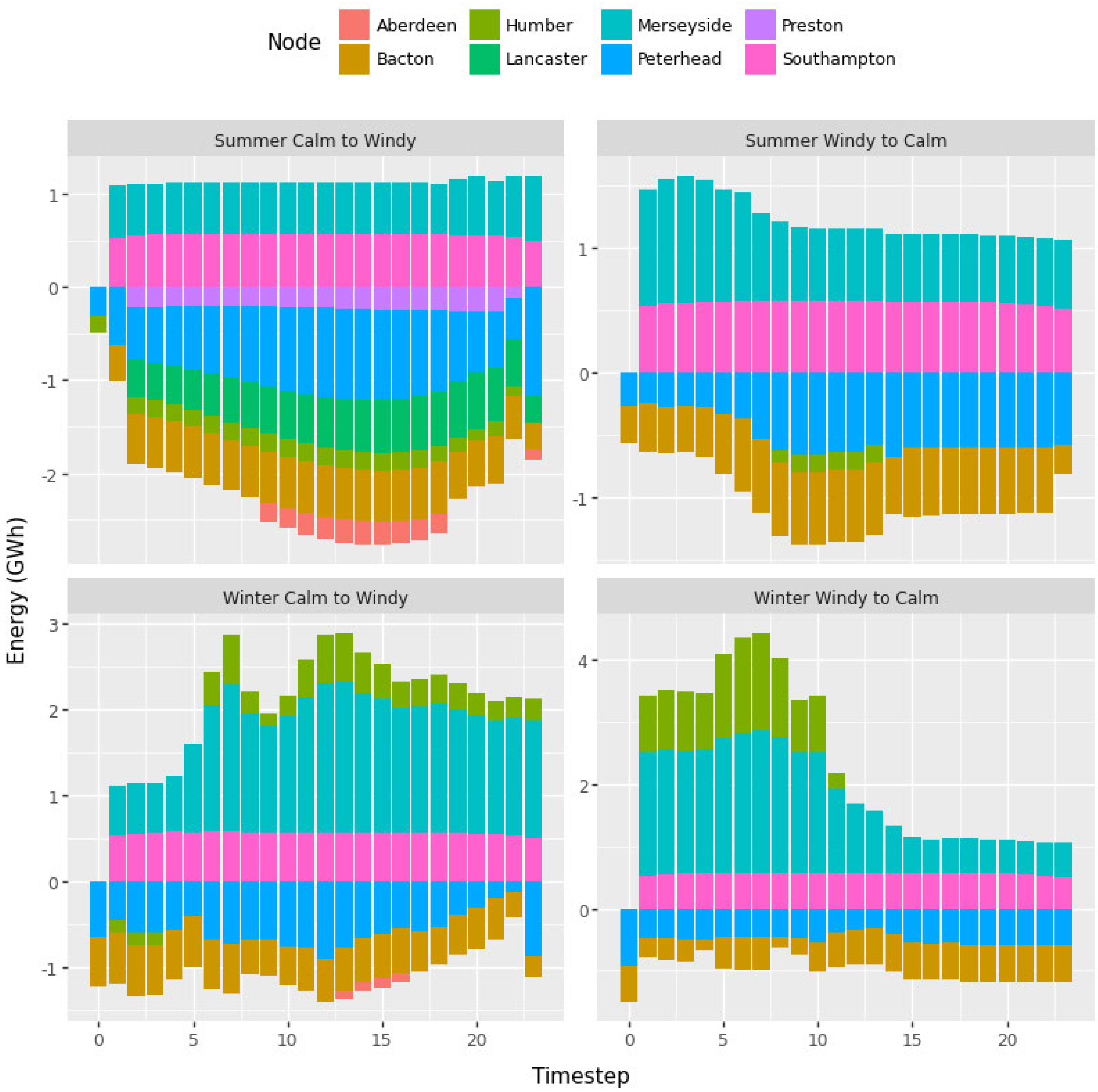

Figure 19 Hourly balancing shortfalls per (approximate) Project Union location

The gas network consistently needs additional gas in Merseyside and in Southampton. These are both Project Union industrial clusters, and this suggests the demand we have included for these clusters is too large for the network (both are supplied by 900mm pipes). However, Merseyside also has a CCHT, and during periods of high wind (which, as described above, we assume introduces a need for synchronous generators to run to support operability) the shortfall is even larger. There are additional shortfalls around the Humber during these periods; a part of the network which also supplies CCHTs with hydrogen.

There are also many parts of the network that cannot accommodate the volume of hydrogen that *could* be injected into the network. This includes Bacton, which, like with the industrial cluster demand, suggests we have assumed a constant injection of gas which is too large for the network (Bacton also has a 900mm pipe connecting it to the wider network). It also includes Peterhead, which has both a constant stream of SMR hydrogen injection at St Fergus as well as hydrogen production from Electrolysis, and at times this issue extends further south to Aberdeen. In some periods, there is more electrolysis that can be accommodated in the Humber. On the Summer

Calm to Windy day, there are also overly high injections in the Northwest around Lancaster and Preston – FES includes very large electrolysis demand in this area.

Figure 20 shows the total gas injection (shown in green) and withdrawal (shown in red) required for residual balancing across the entirety of the Winter Windy to Calm day in GWh.

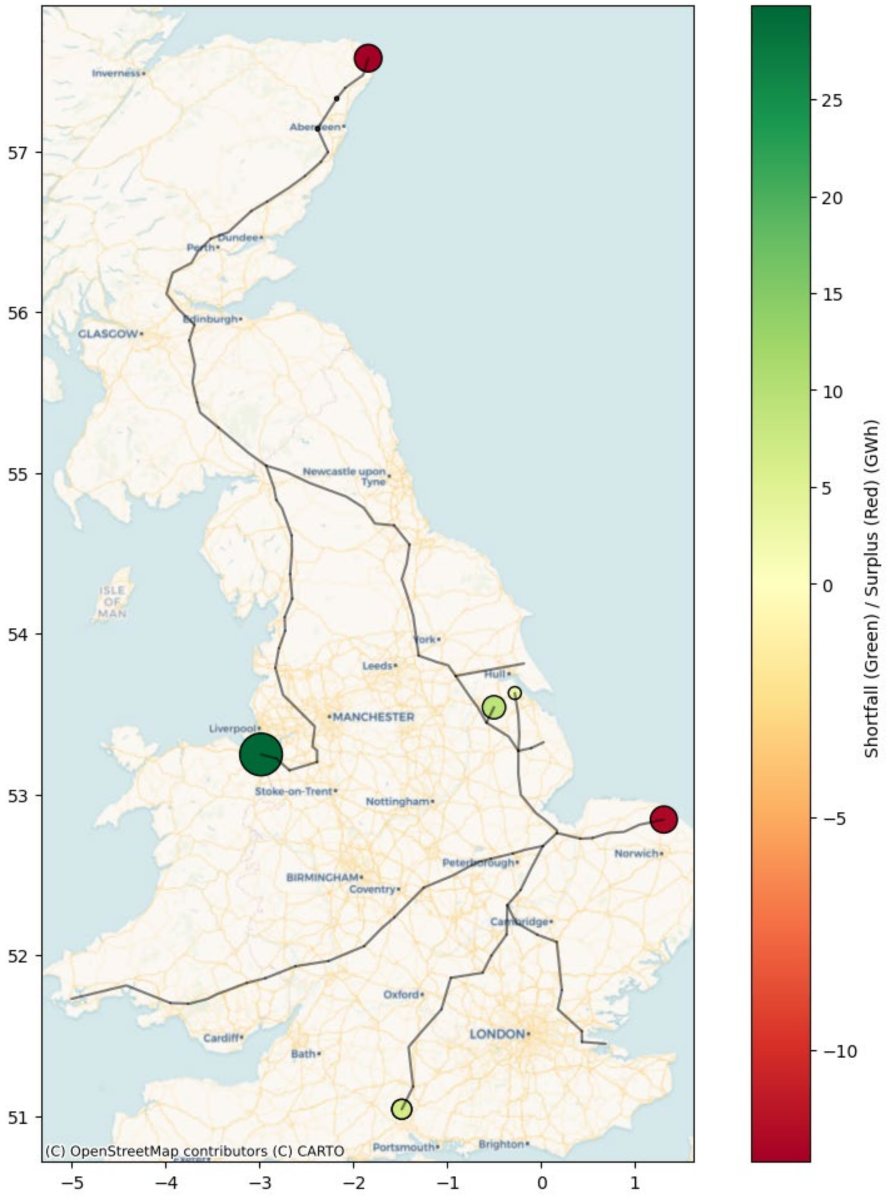

Figure 20 Total gas injection and withdrawal for residual balancing in the "Winter Windy to Calm" day

Coupled model

Next, we show results from the coupled model, where the electricity and gas system are co-optimised. In practice, this allows the electricity system to adapt to the operational restrictions of the gas system and minimise the need for residual balancing of hydrogen flows.

Electricity system

Figure 21 and Figure 22 show how the generation mix changes between the staged and coupled model runs, for each scenario day and in each hourly timestep.

Generation mix

Figure 20 and Figure 21 show how the generation mix changes between the staged and coupled model runs, for each scenario day and in each hourly timestep, compared to Figure 12 and Figure 13. It is clear that, accounting for physical and operational constraints within the hydrogen system leads to quite a different overall dispatch of generation technology, due to limitations on how electrolysers and hydrogen generators can operate within the hydrogen system. In general, the electricity system often requires larger hydrogen flows than the assumed network shown in Figure 3 can accommodate, particularly in segments where the pipes have lower diameters. In these cases, the model struggles to find feasible combinations of pressures and flow rates and therefore needs to adjust the injections and withdrawals of gas.

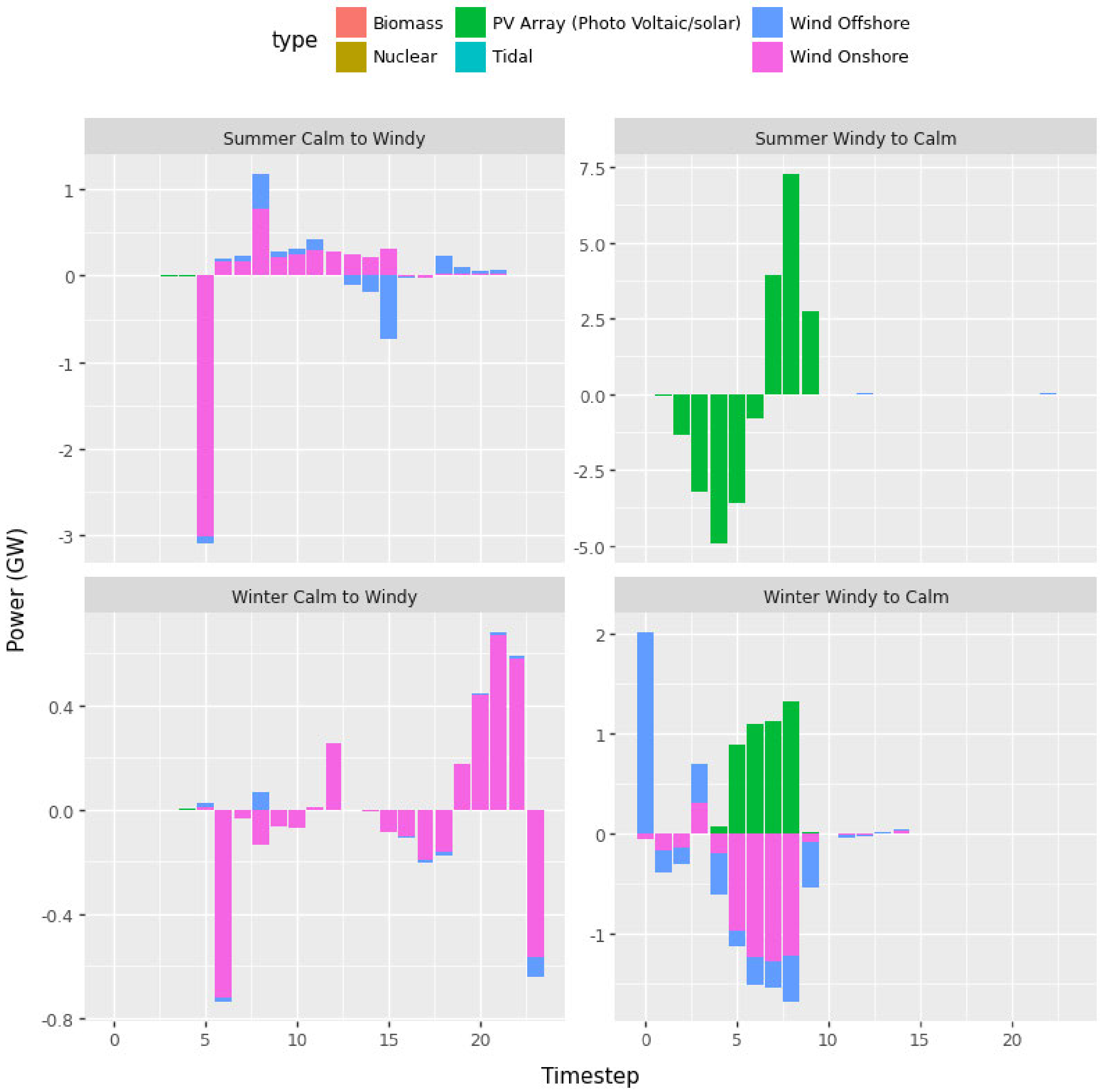

Figure 21 Difference in generation mix for renewables and baseload across all days between the "staged" and "coupled" runs

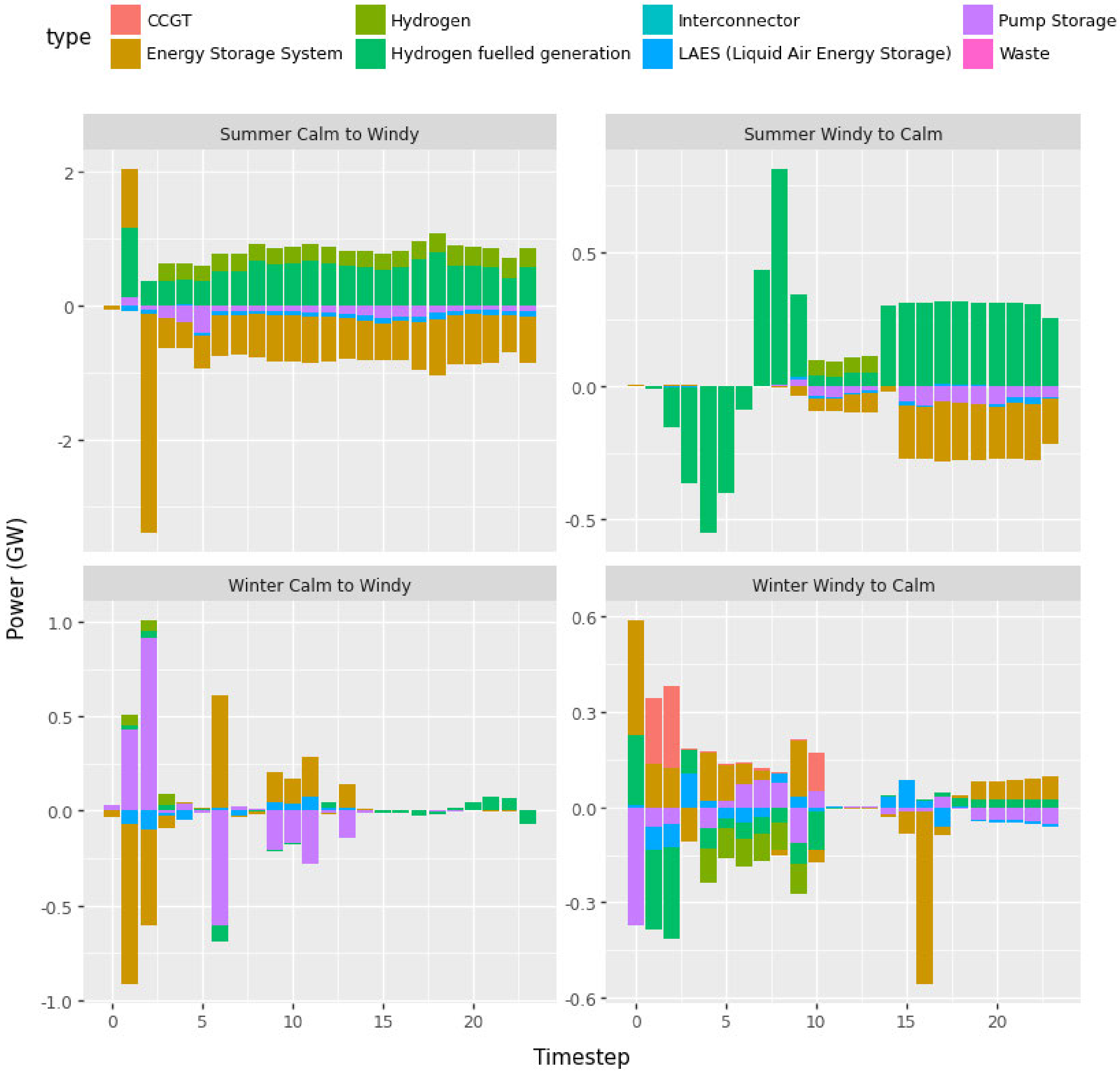

Figure 22 Difference in generation mix for interconnectors and dispatchable power across all days between the "staged" and "coupled" runs

Renewable curtailment

Figure 23 shows how the curtailment of renewables changes between the staged and coupled runs, for each scenario day and for PV, and onshore and offshore wind. The timing and location of optimal curtailment, and the type of generation curtailed, is quite different when the gas system is coupled to the electrical system.

However, Figure 24 shows that the overall volume of curtailed energy across all regions and timesteps is actually quite similar. The change in the total volume of curtailed energy within a day is within +/- 100 MWh for the Summer Calm to Windy, Summer Windy to Calm and Winter Calm to Windy days. Total curtailment increases by 500 MWh on the Winter Windy to Calm day, although this requires more curtailment of Onshore Wind and less of Solar PV (which, based on our assumptions, incurs a greater system cost).

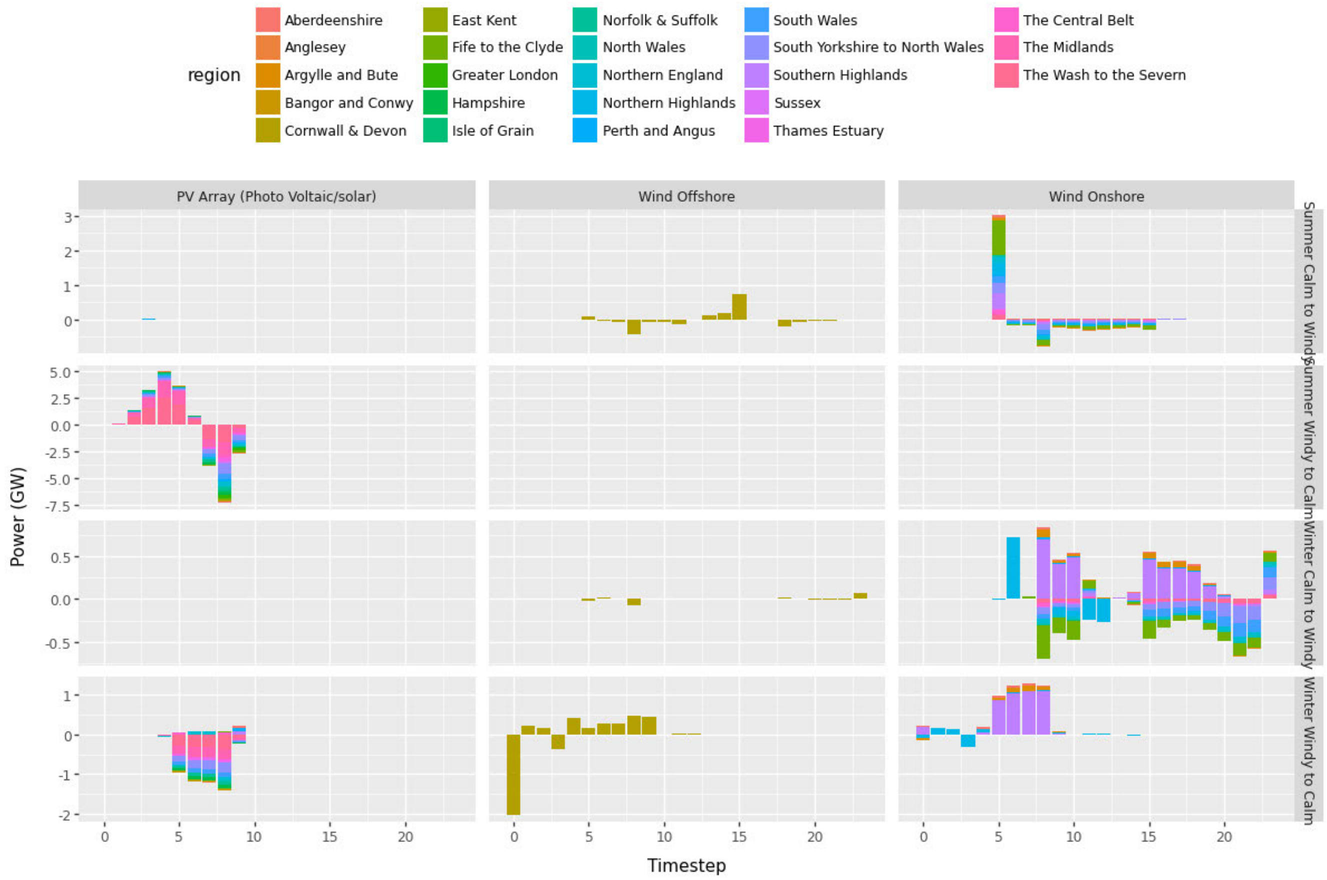

Figure 23 Changes in curtailed renewables between the "staged" and "coupled" models

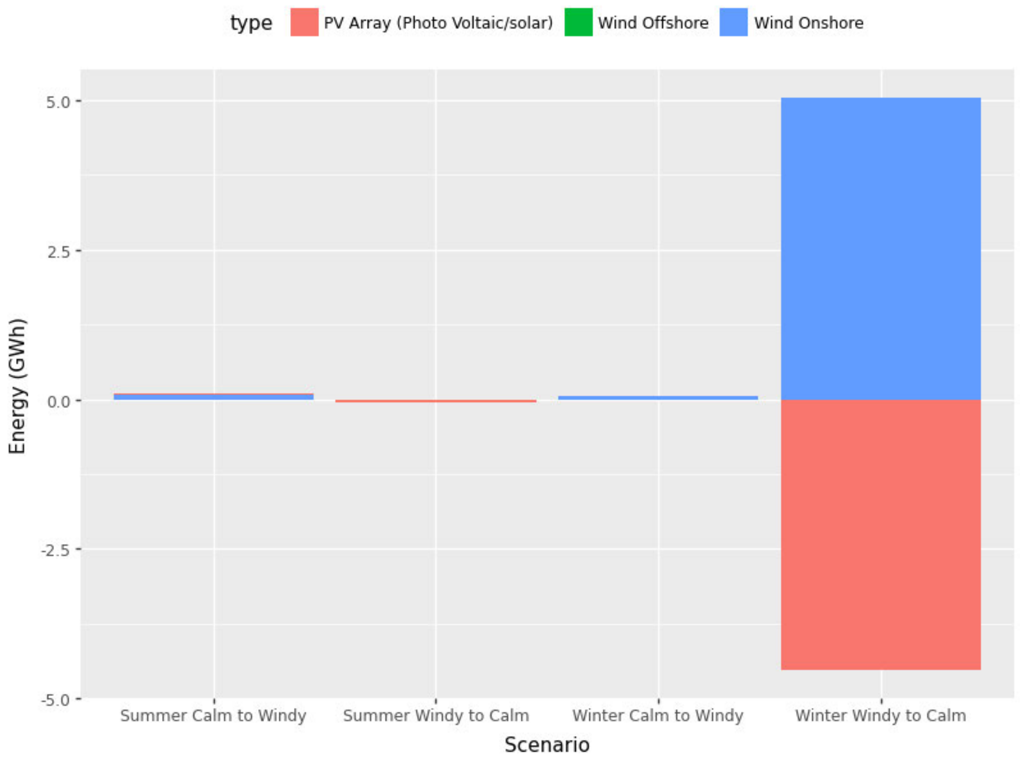

Figure 24 Overalled difference in curtailed energy across all days

Figure 25 shows the spatial distribution of the total daily change in curtailment (of all types of technology) due to coupling the models on the Winter Windy to Calm day, with the scale representing GWh. This shows an increase in curtailment in Scotland, versus an increase in generation output in England.

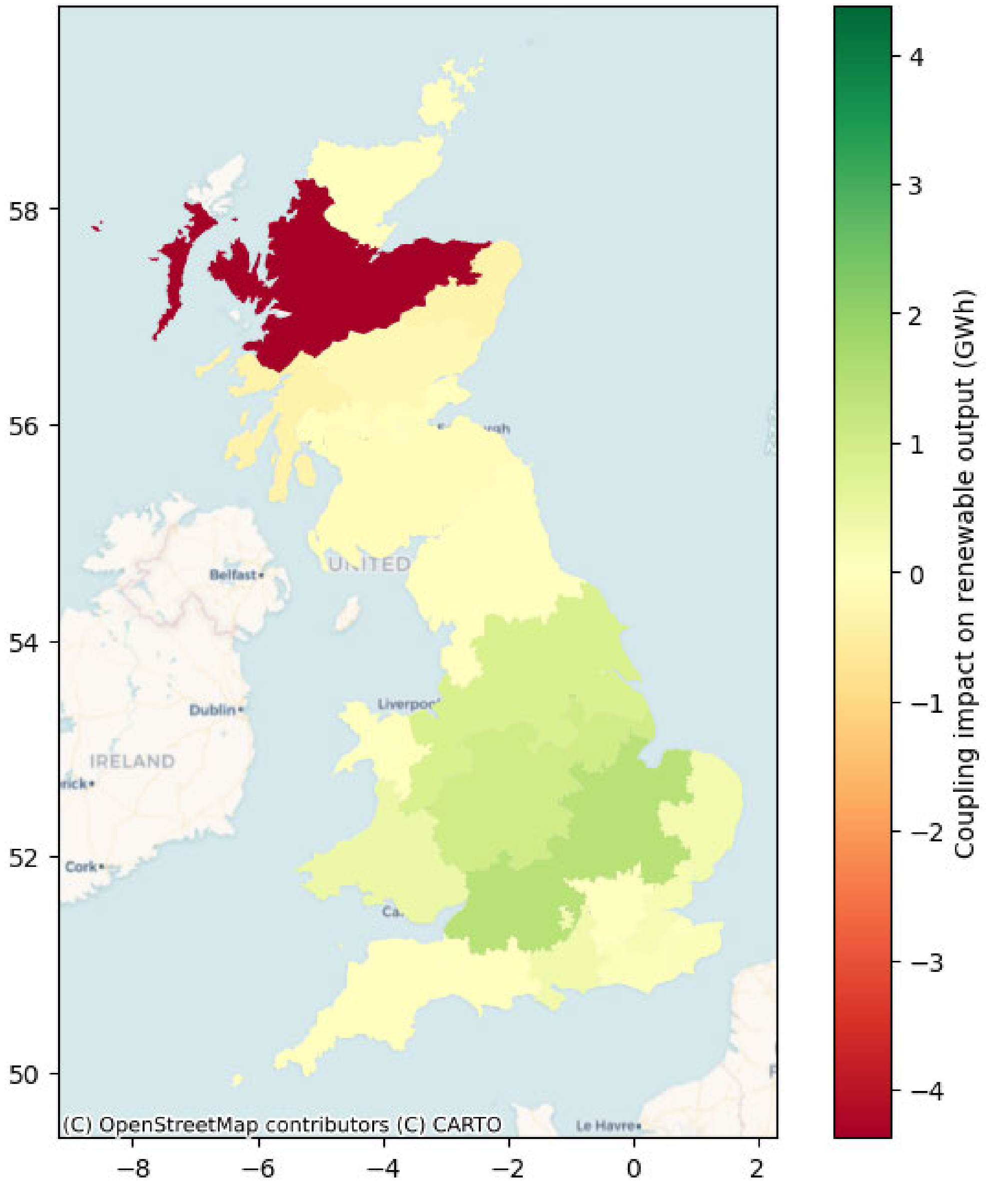

Figure 25 Spatial distribution of the total daily change in renewable output in the coupled "Winter Windy to Calm" day

Hydrogen generation

Figure 26 shows the total dispatch of the hydrogen generators connected the PU network in the staged and coupled model runs. At the national aggregate level, the differences are quite modest in most case, although there is a pronounced increase in hydrogen generation on the Summer Calm to Windy day (which could reflect the need for demand to absorb hydrogen from the linepack of the PU network due to widespread electrolysis injection).

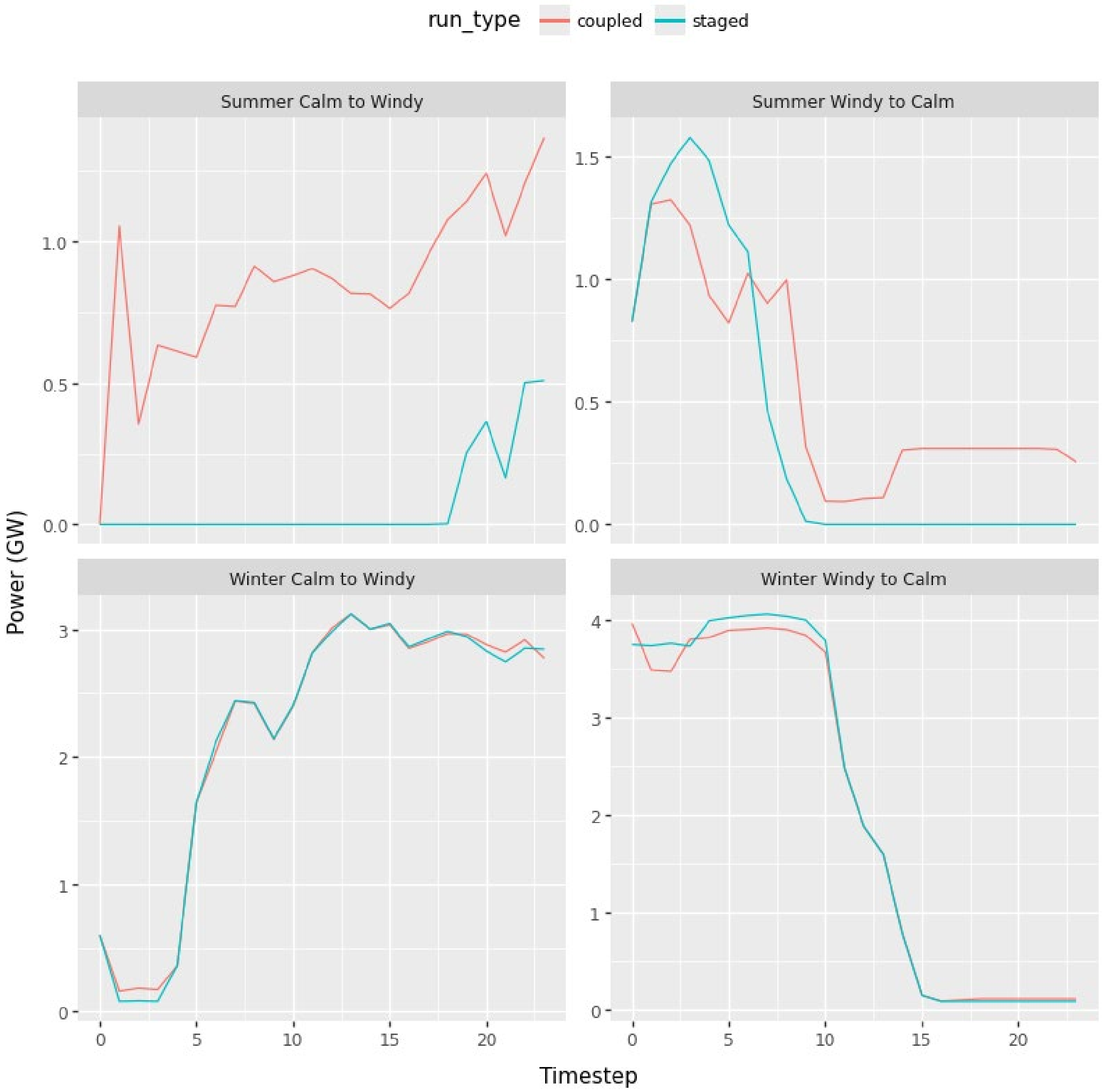

Figure 26 Dispatch of hydrogen generators in the "staged" and "coupled" models

Figure 26 illustrates regional differences in hydrogen generation output, again showing that, while national level outcomes can be relatively similar, the detail of exactly where and when generators are dispatched is quite different. The general trend across three of the four modelled days is to consume less hydrogen for generation in the Northeast of England, and to increase consumption in Aberdeenshire (at Peterhead) in particular. However, in the Summer Calm to Windy day the figure shows there is generally high renewables output in comparison to demand, leading to an increase in hydrogen generation across the system.

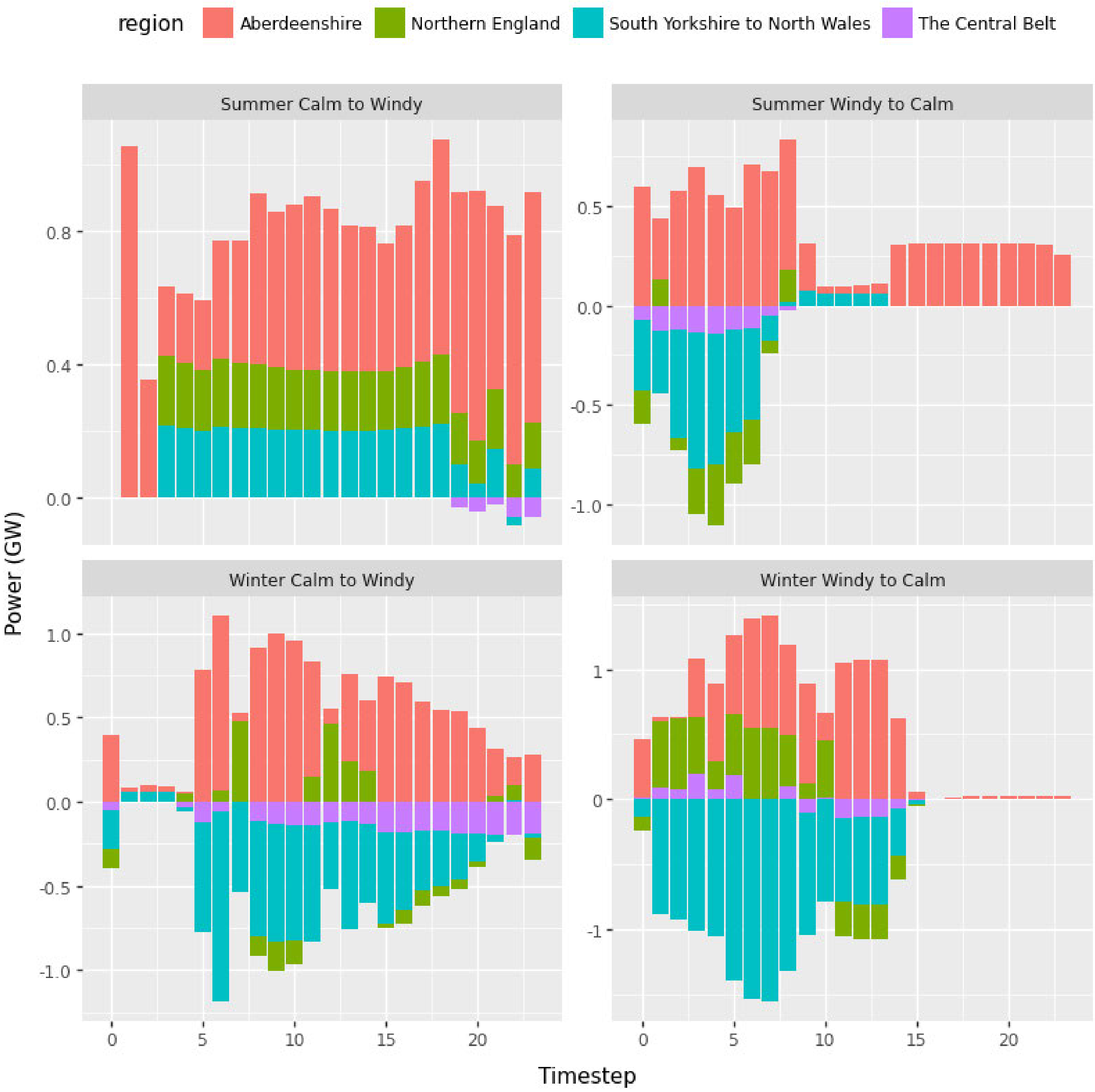

Figure 27 Regional differences in hydrogen generation across all days from staged to coupled run

Figure 28 shows the spatial distribution of the total daily change in hydrogen generation (only including those connected to the PU network) due to coupling the models on the Winter Windy to Calm day, with the scale representing GWh. This reinforces that on this day there is a large shift in hydrogen generation from South Yorkshire and Merseyside to Aberdeenshire, and a smaller shift from the Central Belt (at Grangemouth) to the Northeast.

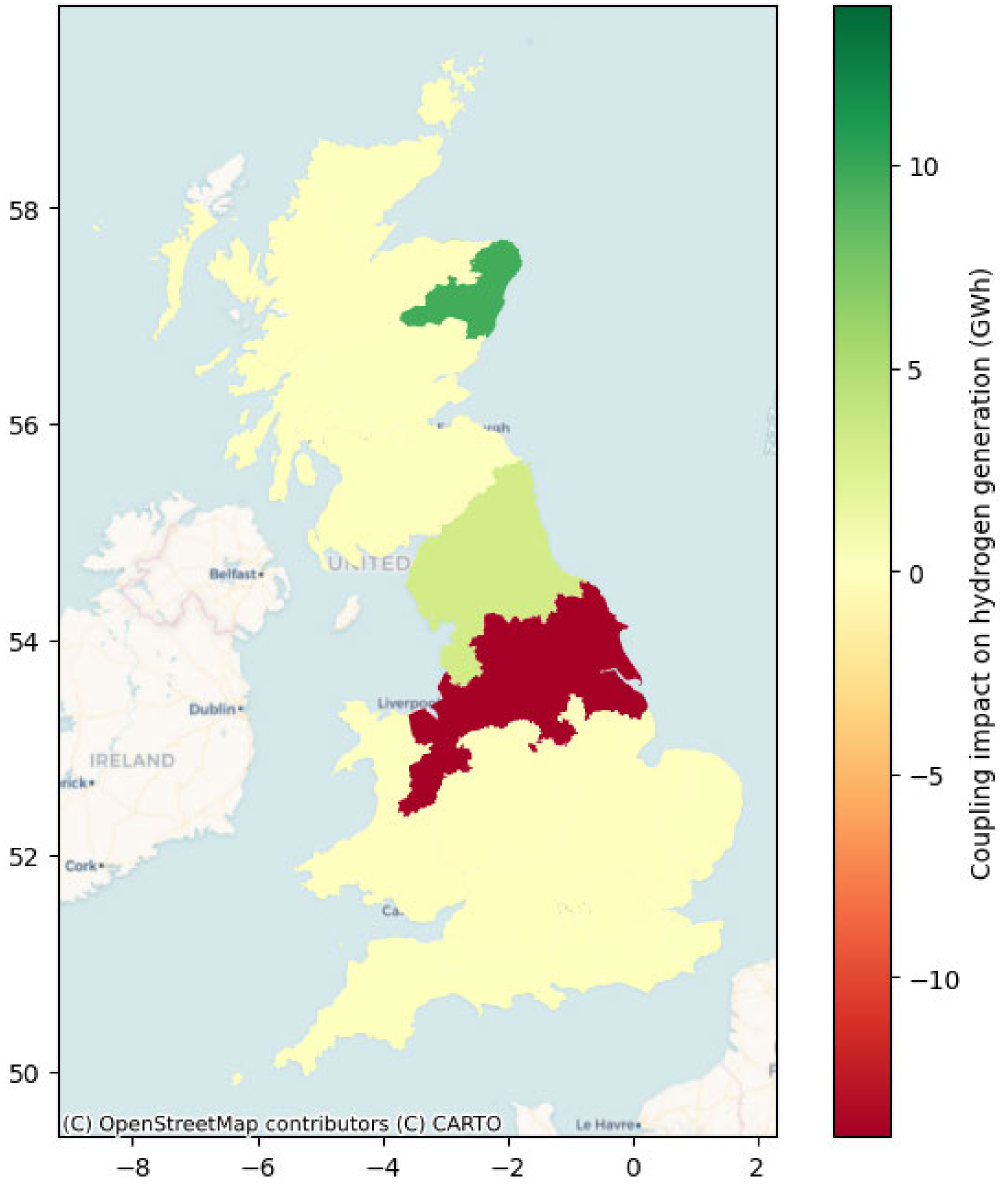

Figure 28 Spatial distribution of the total daily change in hydrogen generation for the "coupled" Winter Windy to Calm day

Electrolysis

Figure 29 shows the total demand for electrolysers connected to the PU network in the staged and coupled model runs. Again, at the national aggregate level, the differences are quite subtle in most cases. However, the spatial and temporal distribution of this Figure 30 is again quite different in some timesteps on some of the days. The most significant difference is on the Winter Windy to Calm day, where the PU network limits the amount of hydrogen that can be injected in the North of England in the first half of day, but more can be injected in other regions later in the day. The two summer days require quite significant changes in the spatial distribution of electrolysis for only one or two timesteps during the day.

Figure 31 shows the spatial distribution of the total daily change in electrolysis (only including those connected to the PU network) due to coupling the models on the Winter Windy to Calm day, with the scale representing GWh.

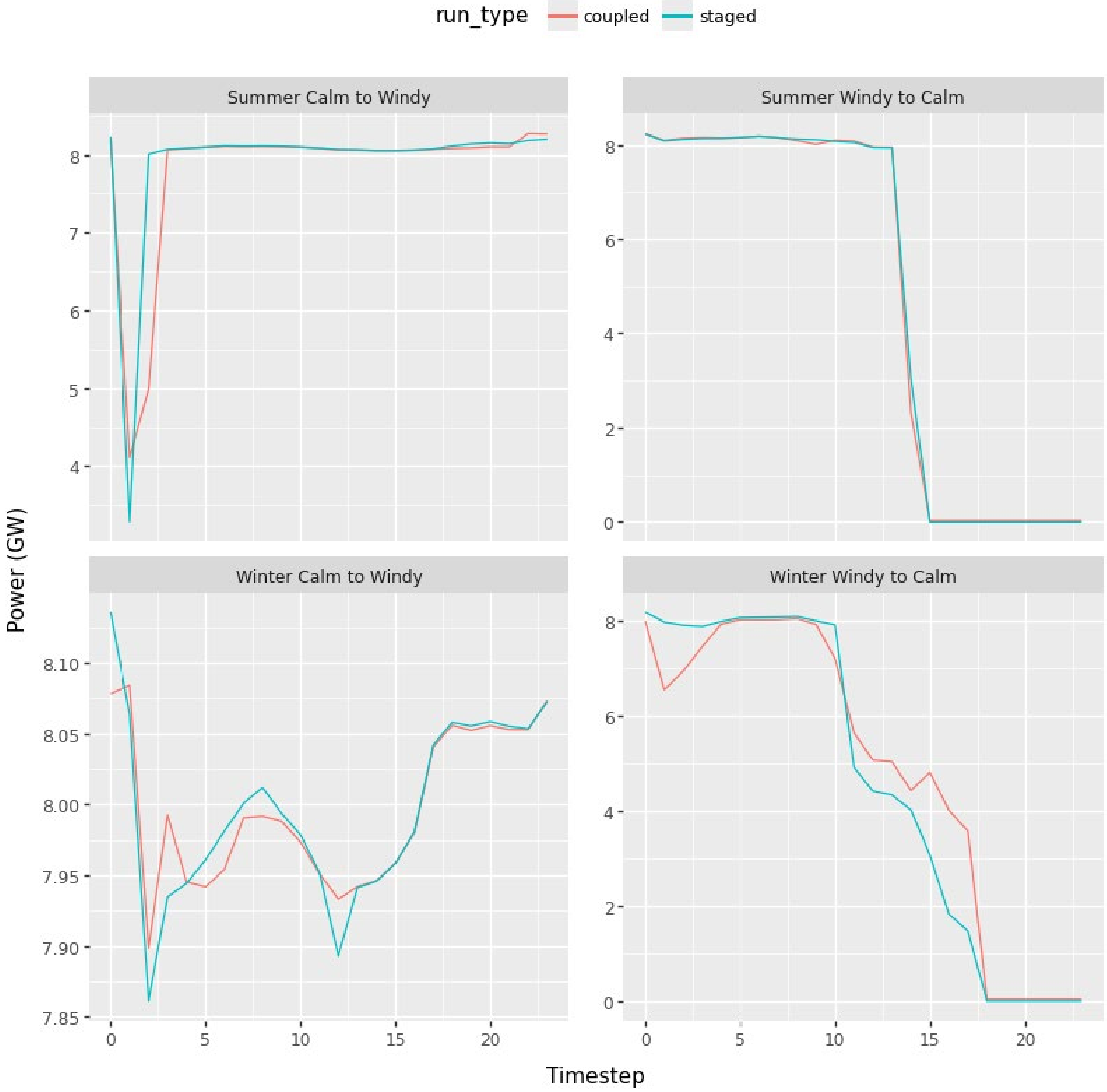

Figure 29 Total demand for electrolysers in the Project Union network for all days

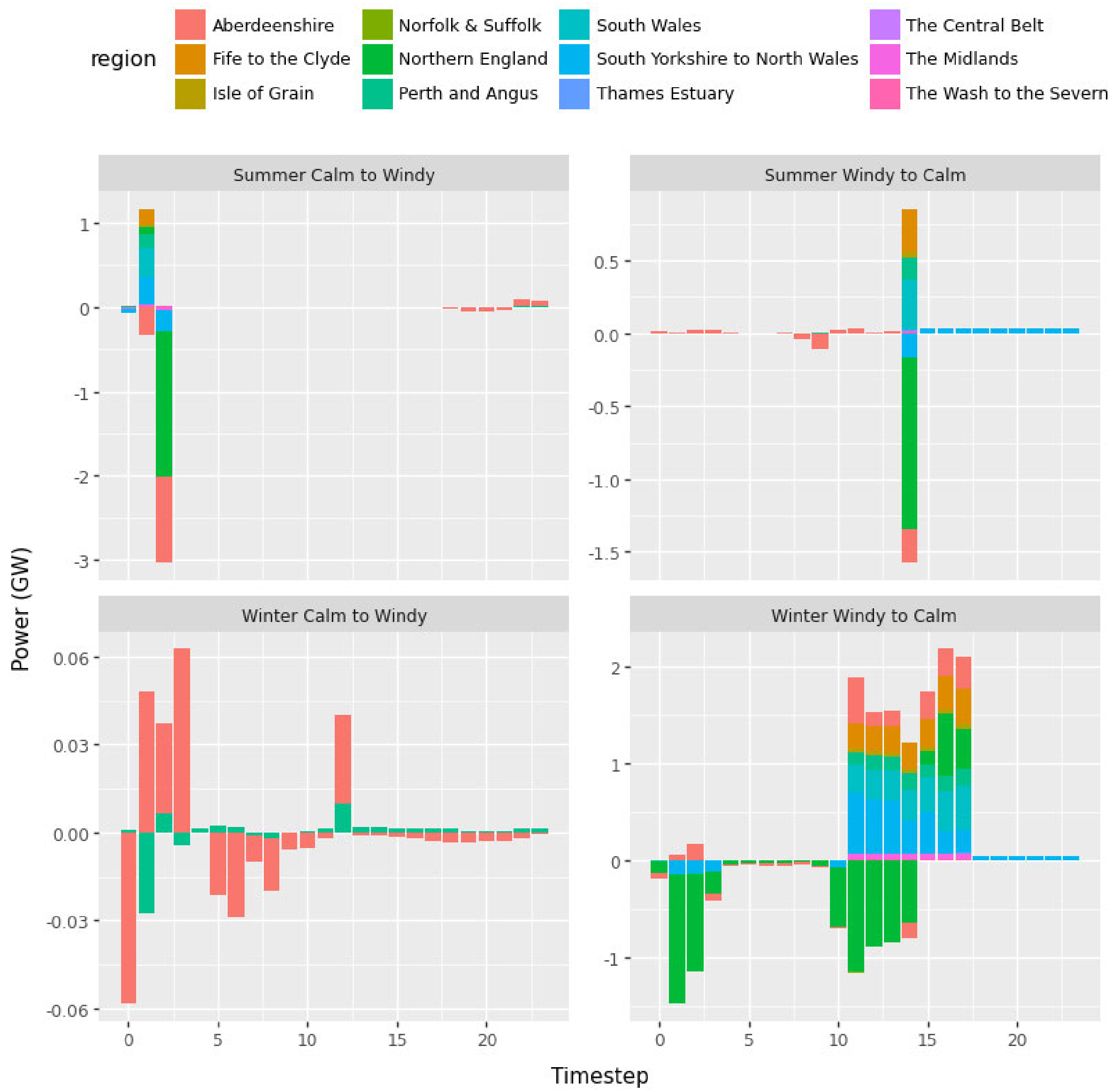

Figure 30 Regional view of the change in total demand for electrolysers for all days from staged to coupled run

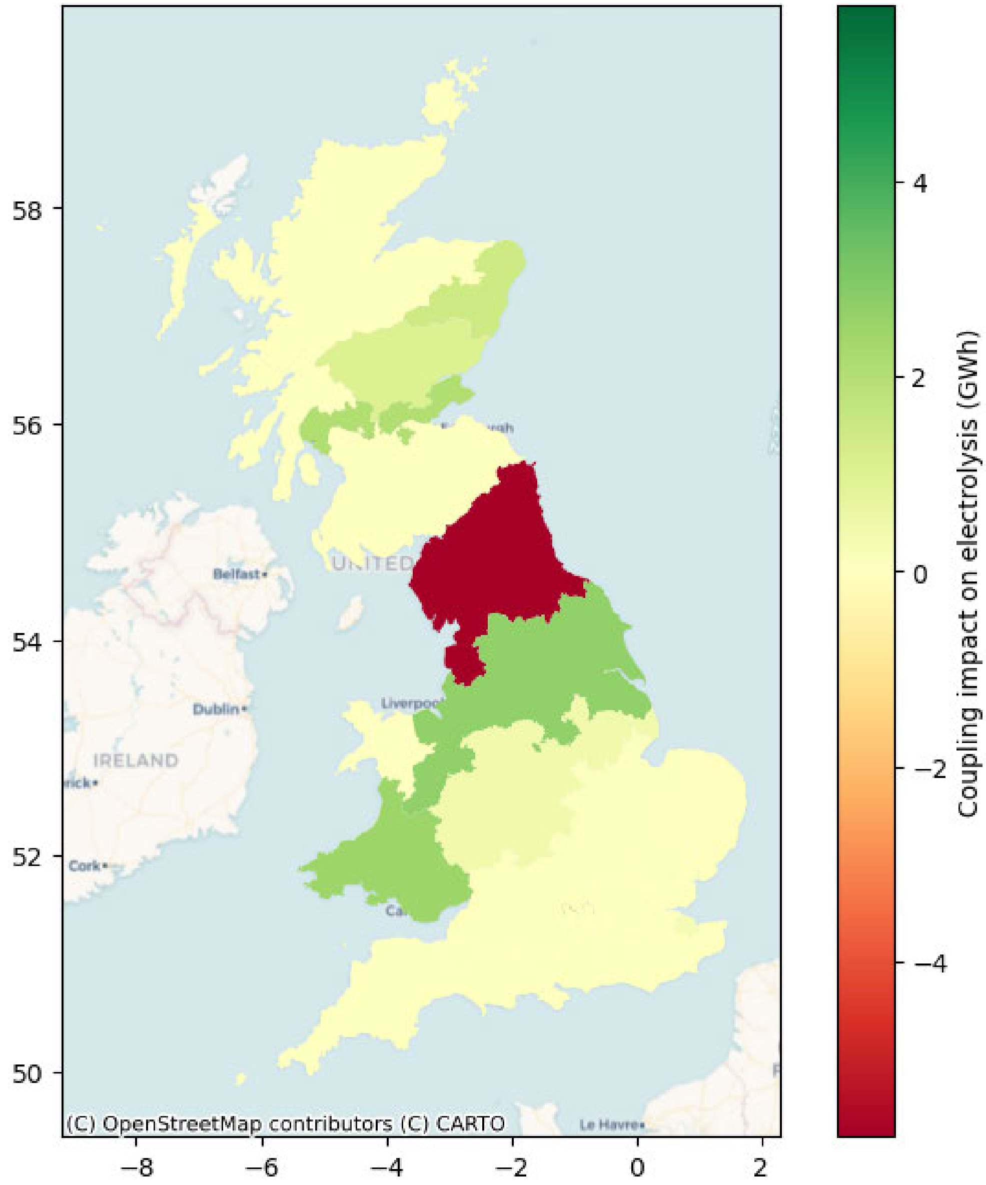

Figure 31 Spatial distribution of the total daily change in electrolysis between the "staged" and "coupled" run of the Winter Windy to Calm day (positive showing electrolysis demand increases, and negative showing it decreases).

Gas system

Coupled injections

Figure 31 shows the total daily injection / withdrawal of hydrogen (in GWh) from Electrolysers and Hydrogen Fuelled Generators into the PU network on the Winter Windy to Calm day. This is another way of visualising the electrolyser and hydrogen generation results, from the perspective of the gas network.

This shows large injection from electrolysis in Scotland, the North-West of England, and South Wales, with high demand at power stations in the Northeast of England and at Peterhead.

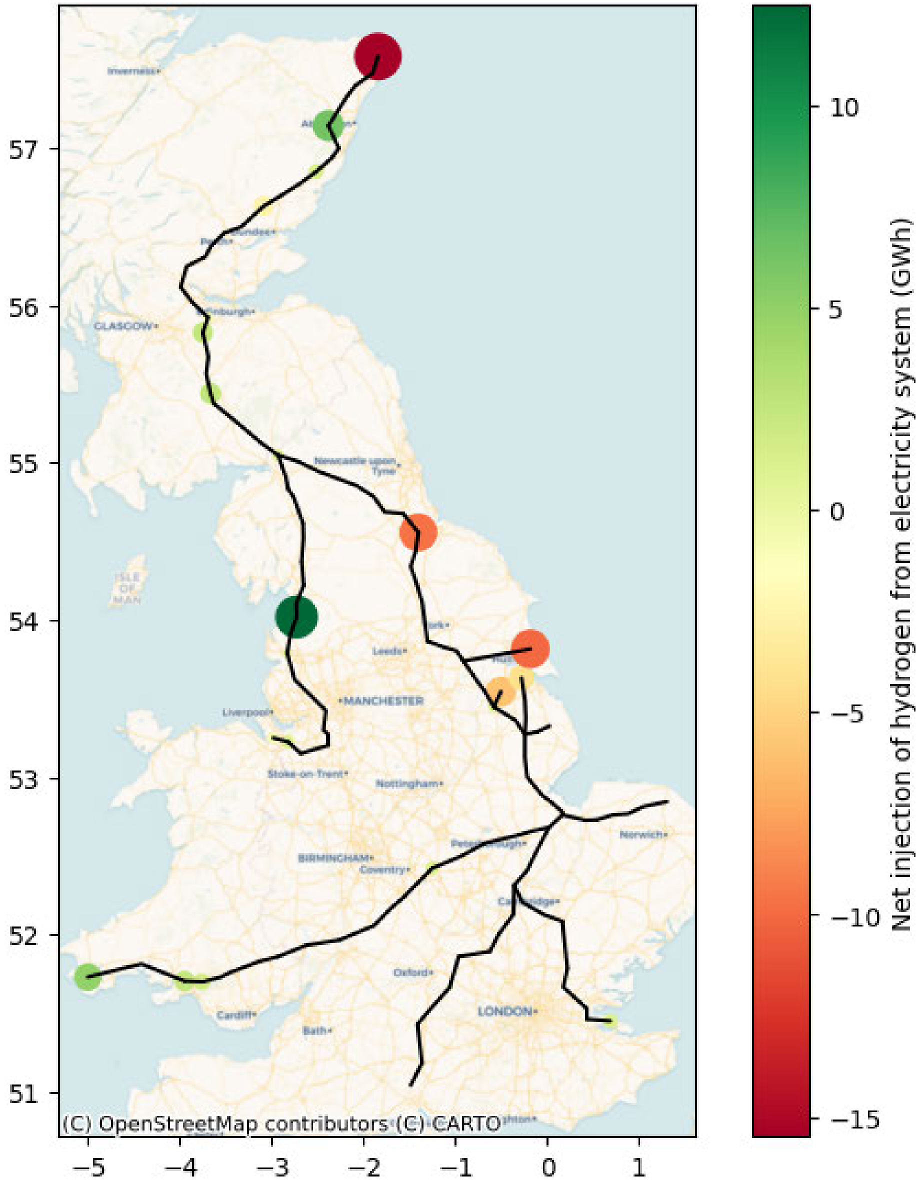

Figure 32 Total daily injection/withdrawal of hydrogen from electrolysers and CCHTs for the staged "Winter Windy to Calm" day

Figure 33 shows how these injections of gas change due to the coupling of the models. In general, coupling of the models reduces the amount of gas being injected or withdrawn from the network (the difference is red where the original output was green, and vice versa).

Interestingly, there is a significant increase in the net injection at Merseyside but in the coupled results there is no injection or withdrawal here; this is because the staged run had selected to run the CCHT in this area, but when coupled together, the physics of the hydrogen network make this impossible. The coupling has introduced the need to run the generator at Peterhead, which was not selected in the staged run.

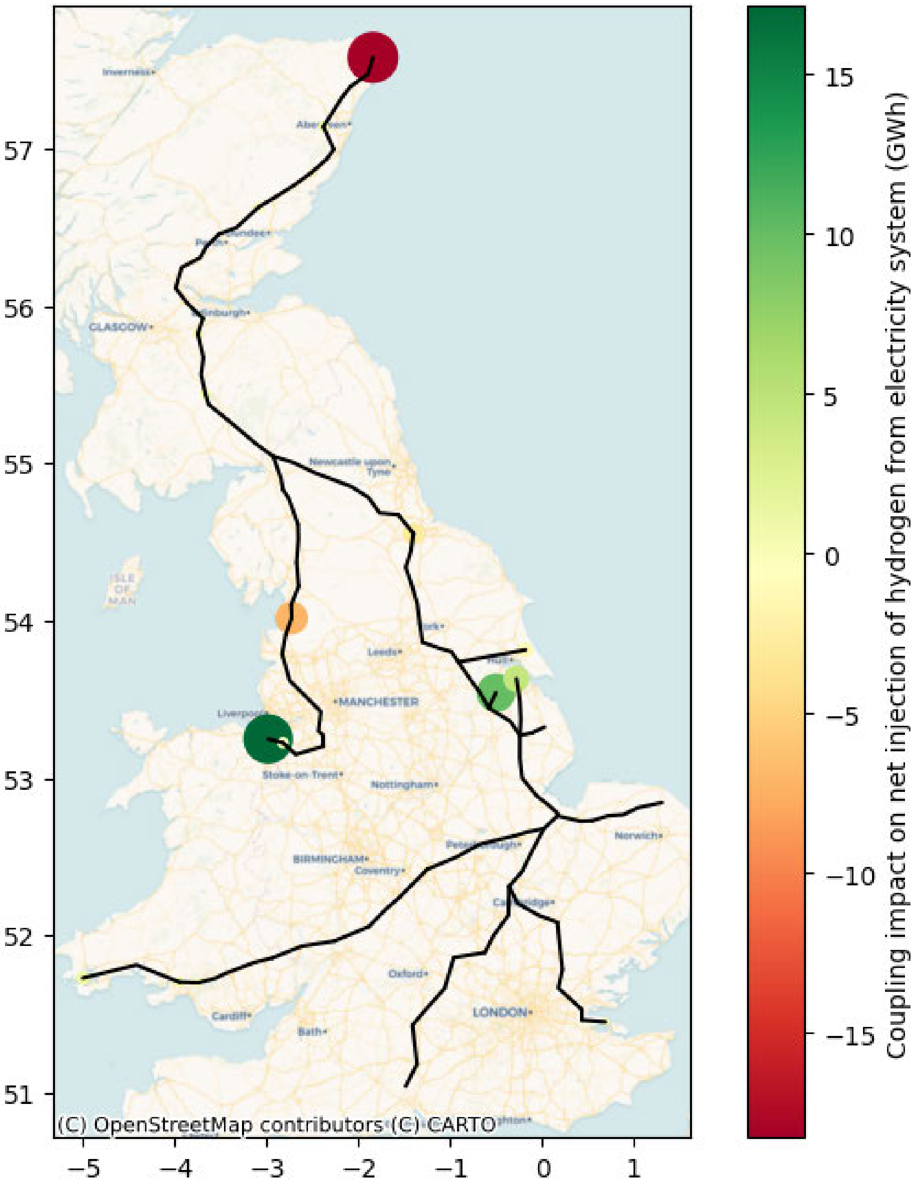

Figure 33 Total change in daily injection/withdrawal of hydrogen from electrolysers and CCHTs between the staged and coupled run for the "Winter Windy to Calm" day

Balancing shortfall

Figure 34 shows the total gas injection and withdrawal required for residual balancing across the entirety of the Winter Windy to Calm day in GWh in the coupled run, which can be compared with Figure 19. Almost all of the residual balancing need is removed, although there is still too much gas at Bacton (where there is SMR production) and not enough at Southampton and Merseyside (both of which have an industrial cluster).

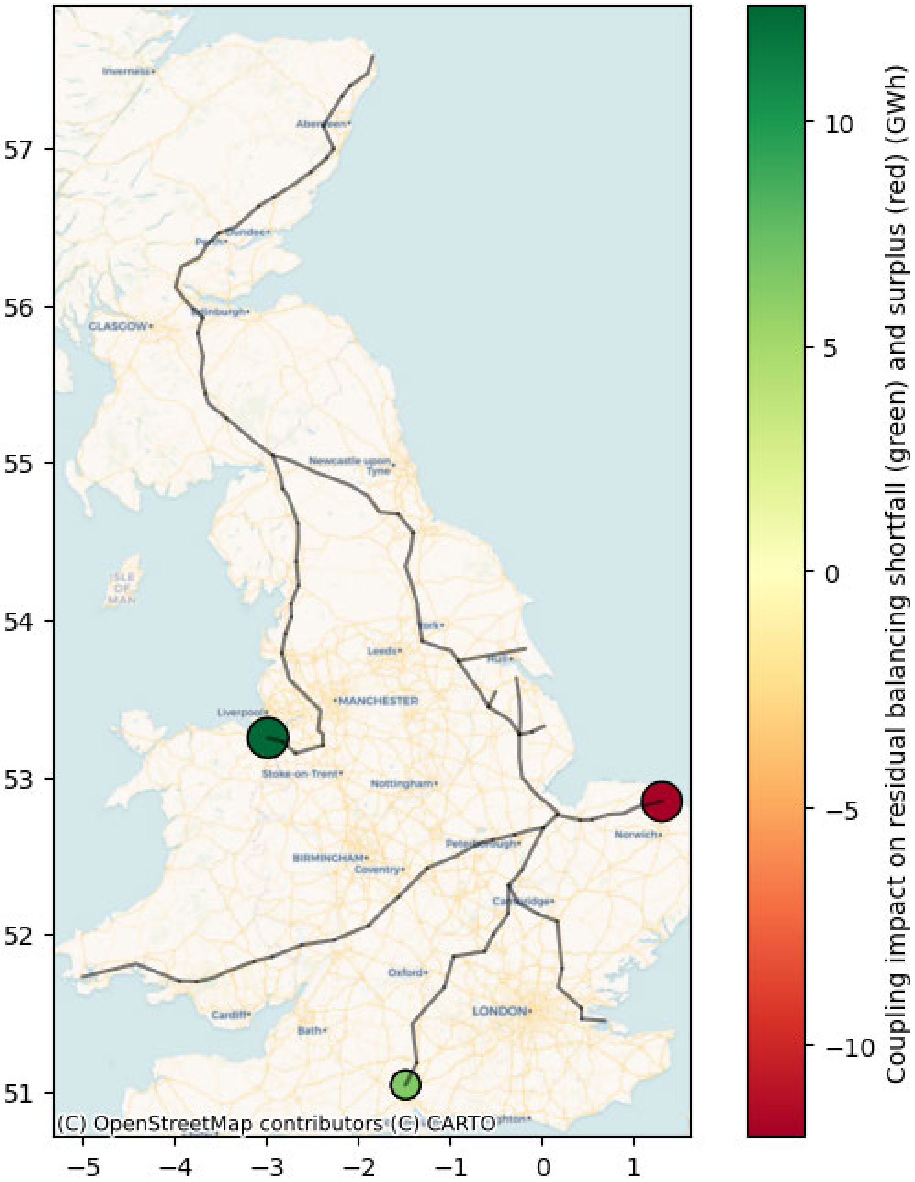

Figure 34 Total change in gas injection and withdrawal for residual balancing for the "Winter Windy to Calm" day from staged to coupled run

Figure 35 shows the change in the gas for residual balancing once the models are coupled together, relative to the staged results in Figure 18. All of the need for residual balancing associated with the electricity system (electrolysis and hydrogen generation) has been removed.

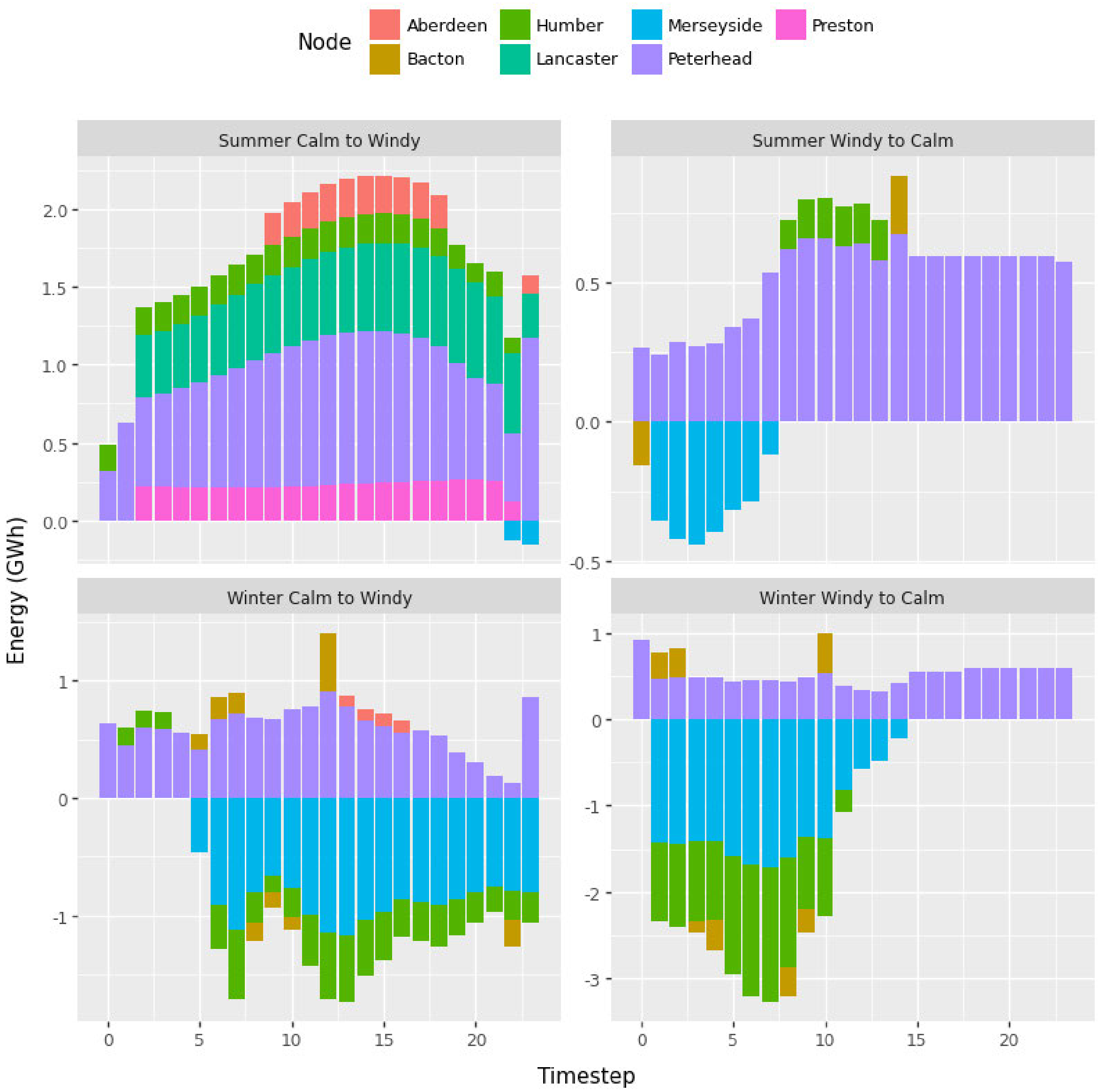

Figure 35 The change in residual gas for balancing between the "staged" and "coupled" versions of the model, for all days

Salt Cavern Storage

Figure 36 shows the volumes hydrogen injected / withdrawn from the network by the salt cavern storage sites. The stores are consistently filling during the Summer Calm to Windy day, and during the calm period of the Summer Wind to Calm day. No hydrogen is injected into salt caverns on the Winter days.

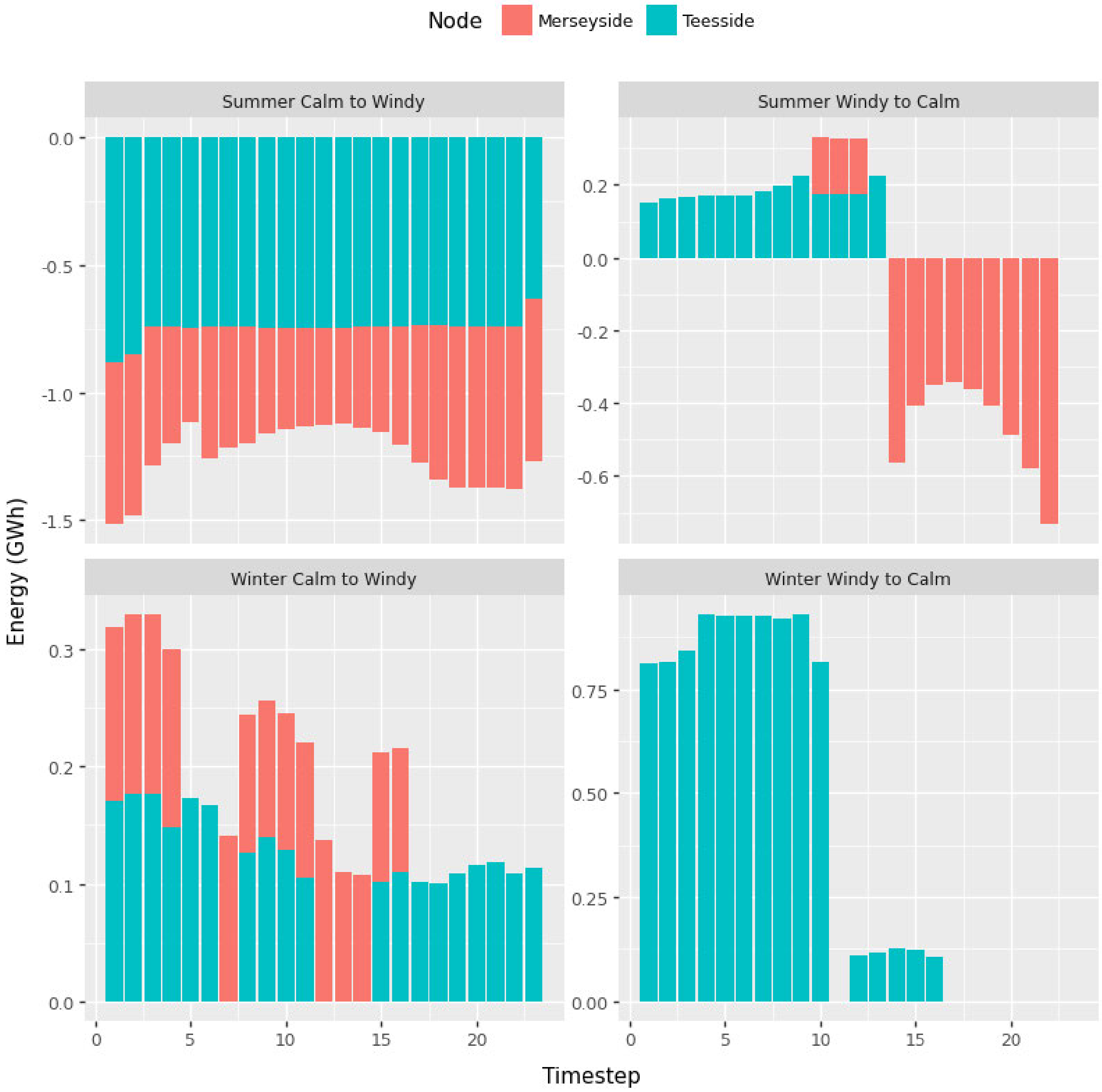

Figure 36 Volumes of hydrogen injected and withdrawn into salt cavern storage for all days

Gas flows

Figure 37 shows the hourly flow of hydrogen in the pipes within the system, distinguishing between pipes where the flow within the day is very steady, and those where the flow is highly variable. Many pipes are used to transport hydrogen at a steady rate throughout the day, but there are others which require quite sudden and / or frequent changes (each row illustrates a different level of variability). in the volume of gas being transported. In the most extreme cases, there are pipes for which the direction of the gas flows must change direction during the day, sometimes several times.

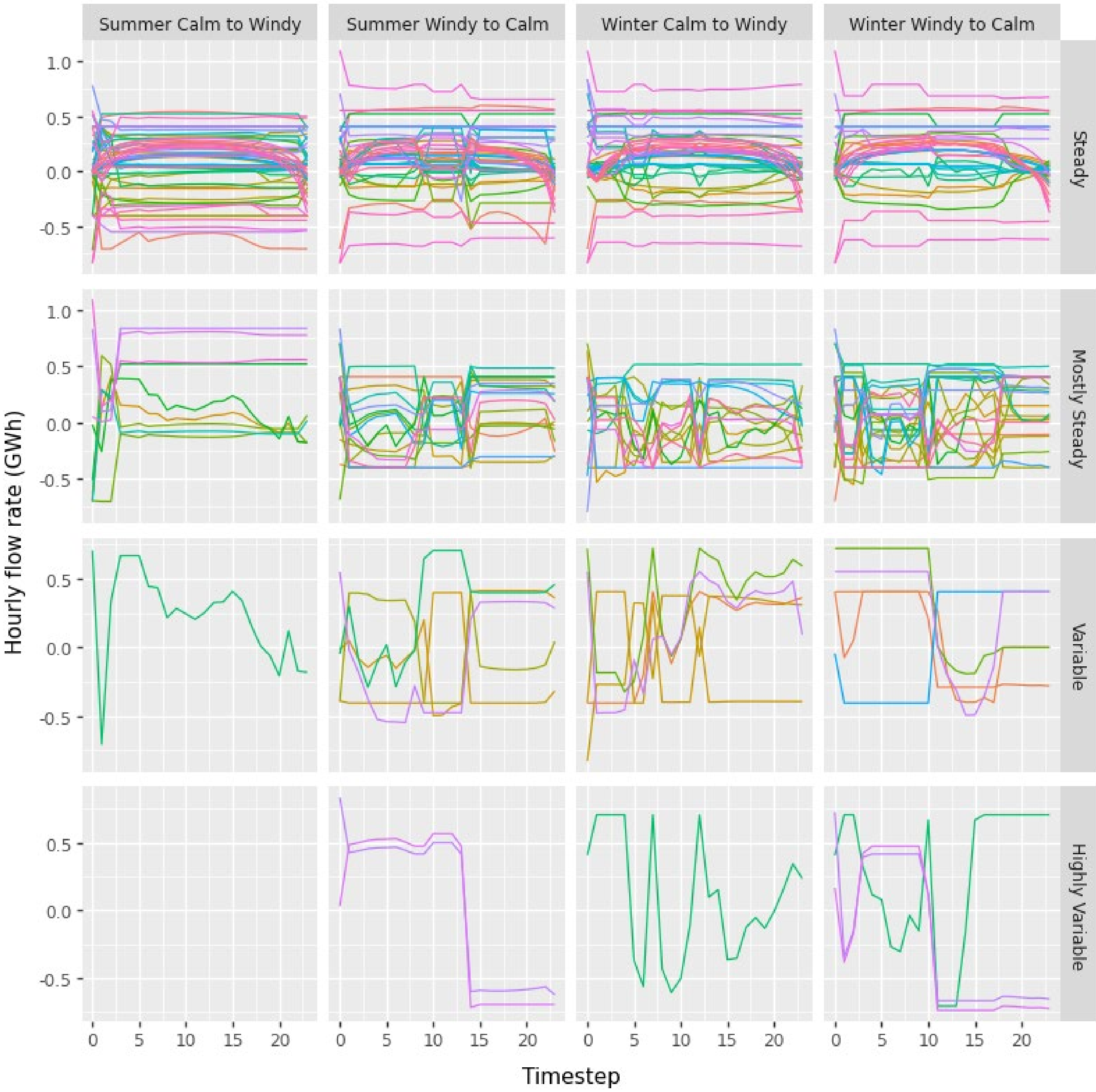

Figure 37 Hourly flow rate of hydrogen across the pipes in the system for all days

Figure 38 presents this geographically for the Winter Windy to Calm day, with net injections and flows of gas in MWh. At each node, blue means the node is injecting gas (whether from coupled technologies, storage, hydrogen only users, or residual balancing requirements), while red means the node is withdrawing gas. Along a pipe, blue represents a north-to-south flow of gas, and red a south-to-north flow. The left-hand plot is for timestep 5 (6am-7am) and the right hand plot is for timestep 15 (4pm – 5pm), chosen to illustrate the difference between period where renewable output is high (and low). .

The long stretches of pipe towards Southampton and Milford Haven have very stable, predictable hydrogen flows. Southampton only includes the industrial cluster demand, and the electrolysis production in South Wales is quite low in volume relative the industrial demand to Milford Haven. Similarly, Bacton injects gas into the system at a fairly constant rate.

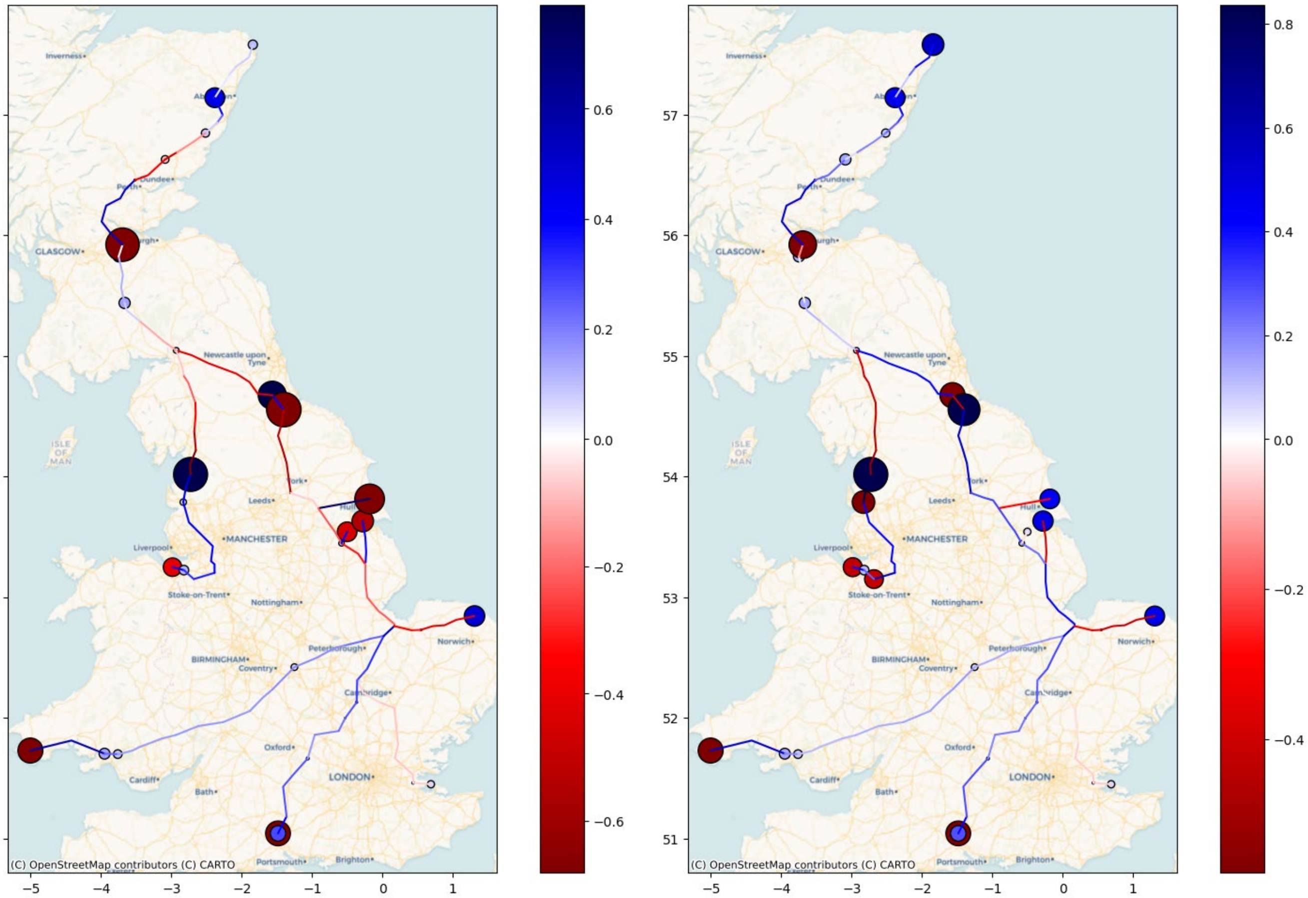

Figure 38 Hourly flow of hydrogen across GB for “Winter Windy to Calm” for 6am-7am (left) and 4-5pm (right)

However, many other parts of the system show much more unpredictable behaviour. The network nodes around the Humber go from being net demands of gas (at 6am) to net producers of gas (at 4pm). The assumption here is that Humber will supply local demands first, and then inject the remaining supply into the transmission system. The flow of gas from Scotland to North-East England reverses direction, as does the flow between Perth and Aberdeen. There is a complex interaction between the users around Teesside, which includes SMR supply, industrial demand, electrolysis, hydrogen demand and salt cavern storage, with flow along a short segment of pipeline in the opposite direction to the rest of the route through the Northeast. At 4pm, all of the supply from Bacton flows South and West, whereas at 6am some of the gas also flows north towards the Humber.

Compression

Figure 39 shows the hourly compression ratio for all the compressors modelled within the system, distinguishing between compressors where the compression ratios are generally quite low, and those where compression ratios are high (in either direction).

The general need for bidirectional compression is very clear, with most compressors going from ratios above 1 to below 1 during the day, or vice-versa. Like with the flow in pipes, there are some compressors that only have quite modest compression ratios (and others with significant swings (including examples where compressors start the day doubling pressure in one direction and finish it doubling pressure in the other direction). This is driven by the location of the electrolysers relative to the generators, meaning gas no longer flows largely in a single direction.).

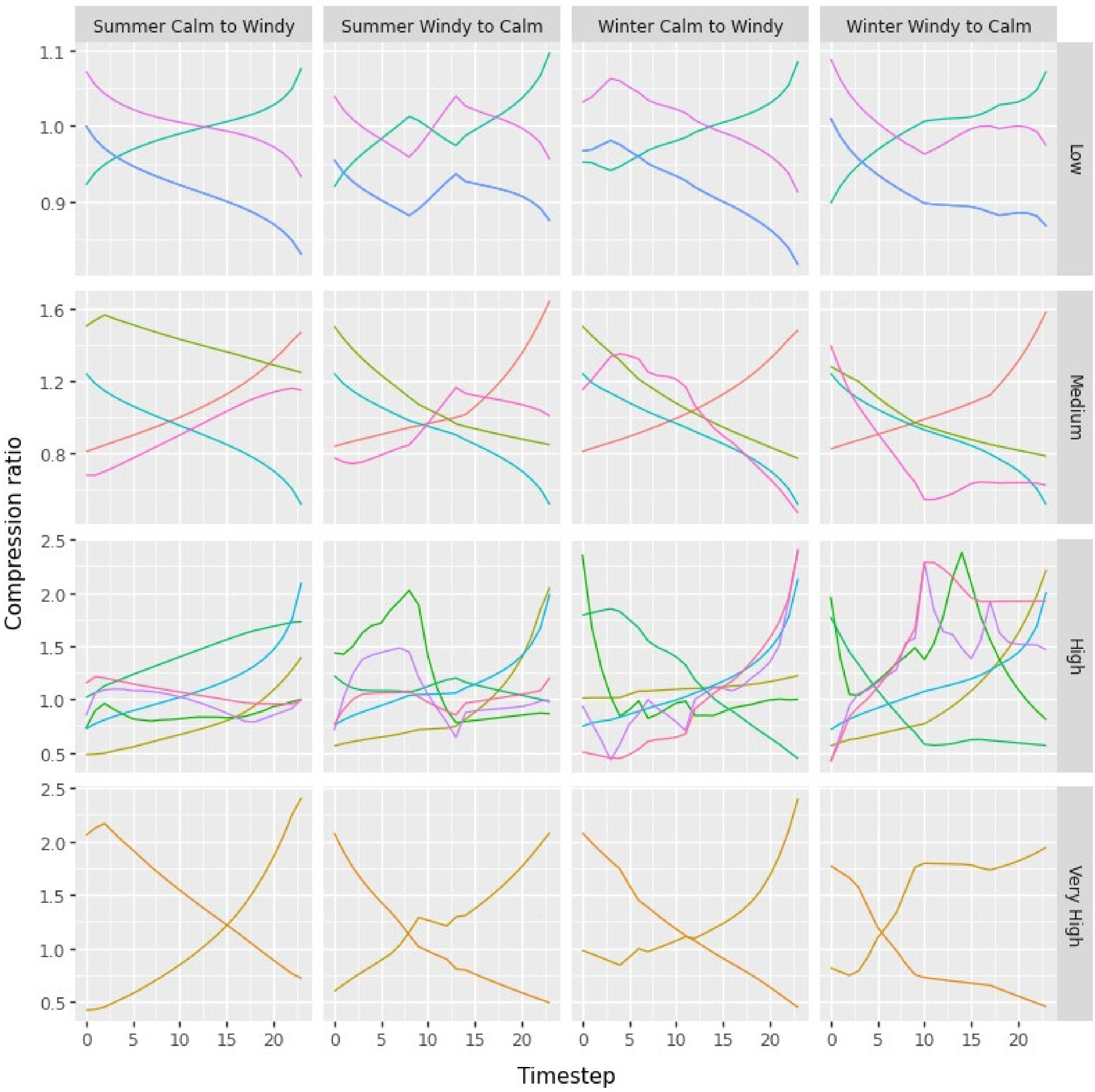

Figure 39 Hourly compression ratios for all modelled compressors

Linepack

Figure 40 shows the total linepack energy throughout the day, with each colour representing a different pipe. Linepack is generally around 300 GWh, an order of magnitude less than the methane NTS. On two of the days (Summer Calm to Windy and Winter Windy to Calm) the total change in linepack is at the upper allowed limit of 30 GWh. It is also notable that the initial linepack is very different on the Winter Calm to Windy and Winter Windy to Calm days.

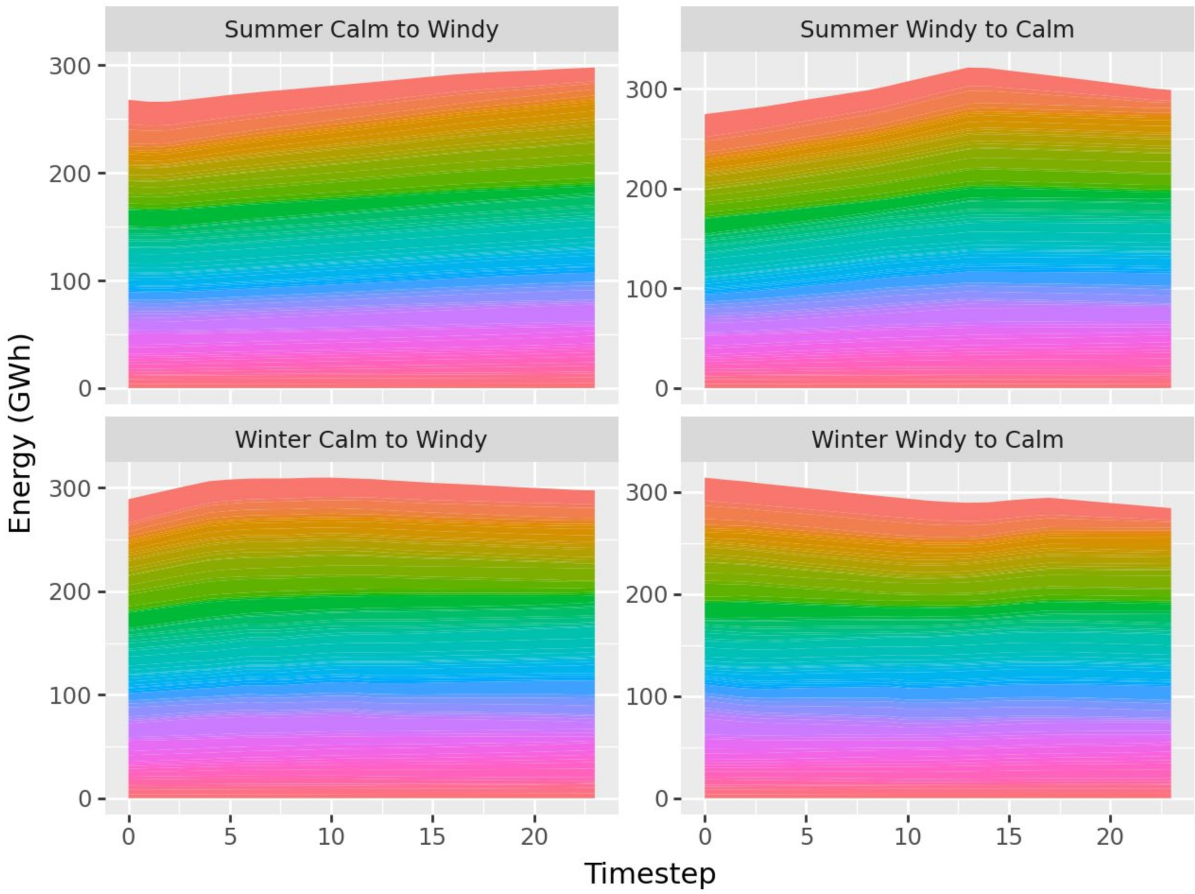

Figure 40 Total linepack throughout the day for all days

Figure 41 shows, for the Winter Windy to Calm day, the density of hydrogen at the start of the day (on the left) and at the end of the day (on the right) (compressors are marked with black dots). While the total linepack has only changed by 30 GWh, the spatial distribution of gas is significantly different.

For example, there is initially a high volume of linepack between the Humber and Teesside, around Grangemouth, near Southampton, near Merseyside, and near Milford Haven; in other words, near the industrial clusters. By the end of the day, the density of hydrogen in these parts of the system is less than half of what it was at the outset of the day.

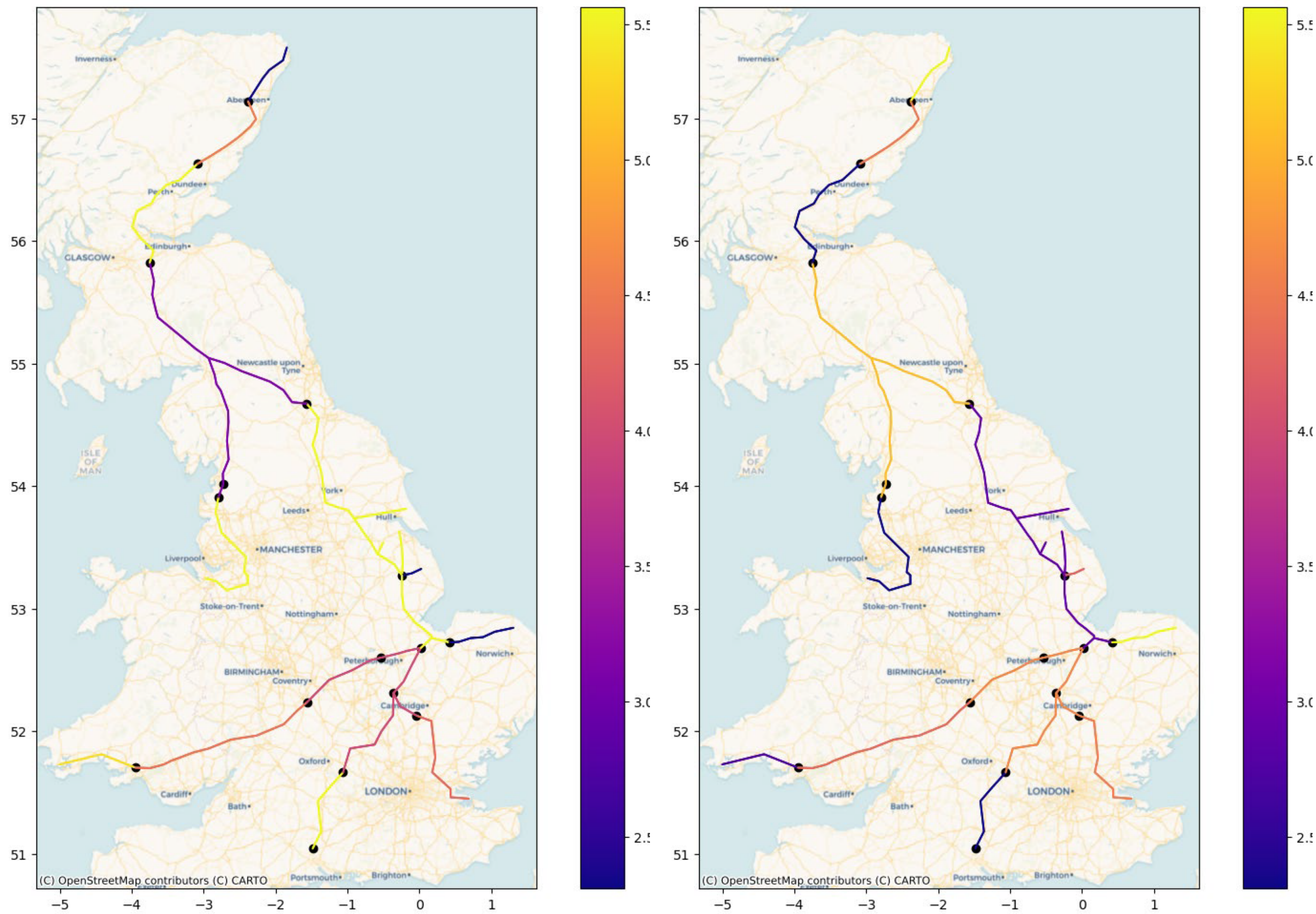

Figure 41 Hydrogen densities at the start of the day (left) and end of the day (right) for the "Winter Windy to Calm" day

Sensitivities

We have made some relatively strong assumptions, particularly about the value of hydrogen and how generation needs to have in the system which could affect the results presented here. We have undertaken sensitivity analysis to examine the impact of these assumptions, including:

- A configuration of the model which doubles the value of hydrogen, which means the electricity system would prefer to use CCGTs and other thermal generators before dispatching CCHTs.
- A configuration of the model which removes the need for certain types of synchronous generator to be operating at 10% or more of demand.

Figure 42 shows the required residual balancing energy for the hydrogen network under these sensitivities in the staged run, excluding the three locations (Southampton, Merseyside, and Bacton) for which the SMR injection and industrial withdrawal requires residual balancing.

In every case, there is still a need for residual balancing actions on the hydrogen network, particularly at Peterhead where gas needs to be remove to absorb the SMR injections and production from electrolysis. The need for additional hydrogen around the Humber disappears in the sensitivity case, as this need was driven by the use of the hydrogen power stations in this region.

However, in some of the modelled days, the sensitivities actually lead to an even greater need for residual balancing actions, particularly removal of hydrogen from the system in areas with high levels of electrolysis (like Lancaster). We expect this arises because, with less usage of hydrogen power stations, there is less hydrogen demand resulting in less capacity to absorb electrolysis.

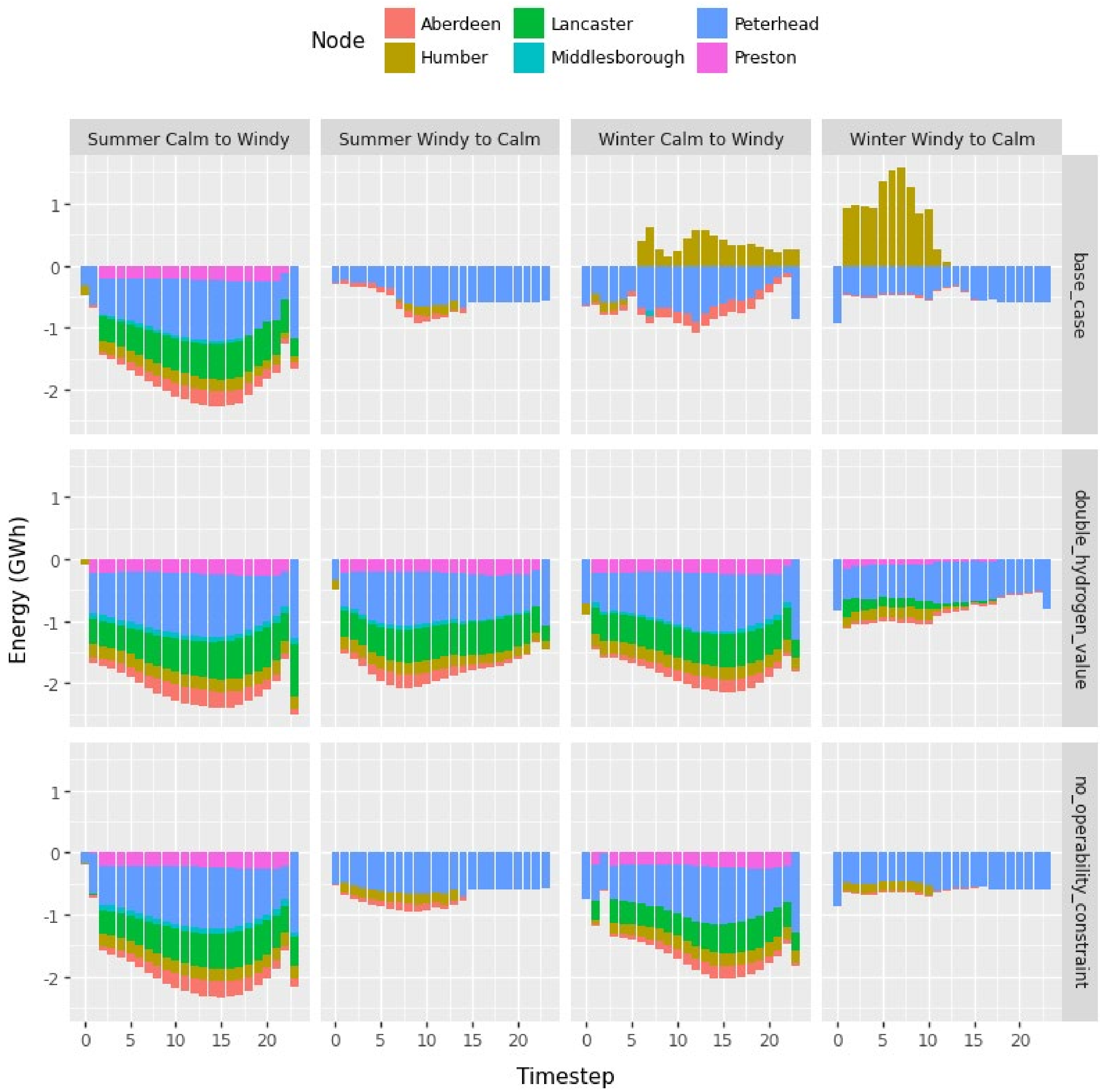

Figure 42 Sensitivity analysis results for residual balancing hydrogen volumes

We have also explored a sensitivity in which we separate the national PU network into six local islands, each centred around one of the industrial clusters. Each island includes some mix of SMR injection, electrolysis, and hydrogen generation, and two of them include salt cavern storage. But there is no capacity for shortfalls in one area to be accounted for by excesses in another.

Figure 43 shows the results. There are a few occasions / regions where there is a greater shortfall of hydrogen in the PU islands case, (e.g. in the Humber and in Hull on the Winter Windy to Calm day), although these differences are quite subtle.

However, it clearly, demonstrates that several regions have reduced capacity to absorb additional hydrogen when not connected to a national network, increasing the amount of negative residual balancing energy (e.g., around Lancaster on all four modelled days, and around Middlesbrough, the Humber, Preston and York on the Summer Calm to Windy day).

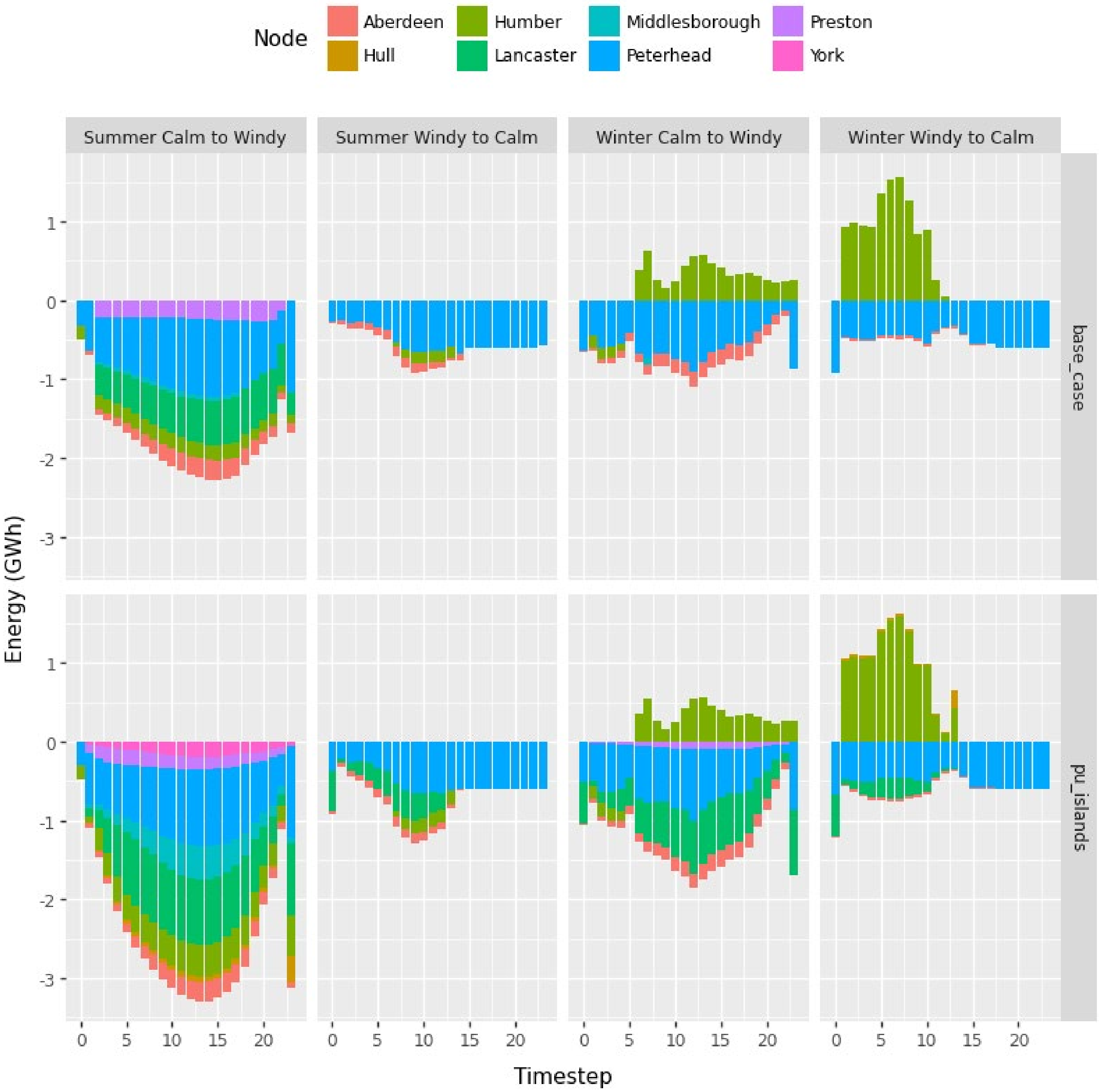

Figure 43 Sensitivity analysis results when islanding the Project Union network around industrial clusters

Chapter 5: Implementation Plan

Implementation Requirements

We have considered both the requirements for Alpha development, and potential future needs for a Beta phase project and beyond into BAU.

Skills and Training

The model development during Alpha has required a mix of specialist skills including mathematical optimisation, programming and software development, and domain engineering knowledge of both the electricity and electricity systems, as well as the assets that couple the systems together (gas generators and electrolysers).

The model developed in Alpha can be installed as a Python package – modular form of code that can be readily integrated into other applications. At this stage it has limited documentation, and is run from a terminal, and as such its use is most suited to developers and superusers. Looking ahead to a Beta phase of the project we anticipate the model will have a broader user base, and that focussed training will be required for these users. However, the exact nature of the training will depend on the final use case and user requirements, as well as the processes for integrating the model and model structures with the various planning processes used across the industry.

Software and Dependencies

The model developed in Alpha has a number of software dependencies, largely based on open-source tools such as Python and the optimisation solving package IPOPT discussed earlier. This can be run locally on a suitably powerful laptop. Looking ahead to a Beta phase, there may be additional software dependencies, such as commercial optimisation solvers, and it may be necessary to deploy dedicated hardware for running the model itself (for example, a standalone server). Work in a Beta phase would consider how to minimise new software and hardware dependencies, and work within the restrictions of existing tools and platforms.

Implementation Approach

The project is actively preparing the FOGSI tool for its transition from the Alpha phase to a Beta phase and ultimately into business-as-usual (BAU) operations. This involves aligning with key stakeholders, defining clear ownership and integration pathways, and addressing training and technical needs to ensure the model can be adopted as a regular planning tool. Below we outline the actions taken to date, the implementation requirements and options for scaling up, and the critical considerations (governance, technical readiness, stakeholder alignment) for a successful Beta and BAU transition.

Implementation Requirements and Product Ownership

As we plan the progression from Alpha to Beta and then BAU, several implementation requirements have been identified to enable scaling and adoption of the FOGSI model:

1. **Product Ownership & Governance:** A clear product owner must be designated going forward. This owner will be responsible for hosting the model and maintaining access to all necessary operational data from the relevant network licensees. Strong governance will be needed to manage data sharing agreements, updates to the model, and its integration into decision-making processes. Early designation of a product owner in Beta (and involving that owner in development) will facilitate a smoother handover and sustained support for the tool.
2. **External Access and Data Confidentiality:** The implementation plan assumes that the model's outputs or certain functionalities will be accessible to external stakeholders (e.g. other network companies or academia) under appropriate controls. The product owner is expected to provide access on a tiered basis, aligning with data confidentiality requirements. In practice, this could mean different levels of data or feature access for internal planners, external partners, or the public. Ensuring the right confidentiality frameworks (e.g. anonymization or aggregation of sensitive data) will be important so that the tool can be useful widely without compromising any proprietary or sensitive information.
3. **Open Methodology and Code:** In line with innovation best practices, the methodology and codebase for the FOGSI model will be made publicly available. This open-access approach (e.g. hosting the code on GitHub during Alpha) encourages transparency, peer review, and future collaboration. It also means that the knowledge from the project can be leveraged by others in the energy sector, and it facilitates easier transfer of the tool into different IT environments. However, open-sourcing the code also implies a need for ongoing maintenance, the product owner or developer will need to manage version control, contributions, and updates in the long term.
4. **Funding Pathway:** A plan for sustainable funding of the tool's maintenance and enhancement in BAU is required. The project team notes that after the SIF Alpha phase, funding will likely need to come through regulated business plan commitments or other BAU budgets. This is under discussion, for example, inclusion in future regulatory business plans or innovation allowances. Early clarification of funding sources for the Beta phase and post-Beta deployment will mitigate the risk of resource gaps when the project transitions out of the innovation framework.
5. **Integration & API Development:** To embed FOGSI into operational planning processes, the model will need to interface with existing tools and databases. Developing an API or other integration layer is anticipated, potentially requiring third-party software development support. This API would allow the FOGSI optimisation engine to pull necessary input data (e.g. network models, scenario data) from NGT/NGET/NESO systems and to feed its results into planners' toolkits (such as PLEXOS or other models). A robust integration is crucial for technical readiness – without it, there's a risk the model remains a stand-alone prototype rather than a seamlessly used planning tool. We will aim to minimize custom development by leveraging existing platforms or interfaces where possible, but some software development will likely be needed to achieve a production-grade, user-friendly interface in Beta.

Decisions for Alpha

During the Alpha phase, the project team has engaged closely with National Gas Transmission's (NGT) System Capability team and with National Electricity System Operator (NESO) teams (Whole System Planning and Net Zero Operations). This early engagement was aimed at aligning the FOGSI model with existing business-as-usual (BAU) future system planning tools and processes. Additionally, the team considered how the FOGSI solution could integrate into the wider NGT IT system architecture, identifying any architectural or data interfaces needed to embed the model into current systems.

[redacted]

Implementation options

A major decision for the implementation plan is how to technically and organisationally transition the FOGSI model from the current Alpha setup into a long-term home within the GB energy ecosystem. Two high-level options have been proposed for the Beta phase and BAU scaling, as summarised in Figure 44 below. These options differ mainly in which organisation's IT environment will host the model during the Beta phase and how the handover to BAU is executed.

The solution is currently being developed on Github:

[redacted]

Figure 44 Implementation options

[redacted]

In weighing these options, the project team is carefully considering governance and stakeholder alignment, technical readiness, and risk mitigation:

Governance & Stakeholders

[redacted]

[redacted]

Technical Readiness

[redacted]

[redacted]

Risks and Recommendation

[redacted]

[redacted]

[redacted]

Training, Skills, and Technical Dependencies

Developing and using the Alpha model requires a fairly niche mix of skills

- Mathematical optimisation
- Python, particularly Python optimisation in Pyomo
- Domain engineering knowledge of electricity system, the gas system, and gas generators / electrolysers.

The model can be installed as a Python package that is run from a terminal and has limited documentation. As such, the model is most suited to developers and superusers.

Beta will require focused training for a wider user base, but this will depend on the exact nature of the GUI and data inputs. Domain training (e.g. electricity networks training for gas engineers) may be beneficial.

During Alpha, we have been able to run the model locally on high-spec laptops without needing special hardware. This is encouraging for prototyping, but as we move to Beta/BAU, we must consider scaling and performance. Depending on the complexity and size of future use-cases, the Beta model may require more powerful solvers or computing platforms. For instance, we might integrate a commercial optimisation solver if that significantly speeds up run-times or improves solution robustness, though this introduces licensing costs and dependencies.

Likewise, if scenarios in Beta grow (e.g. modelling a full year or more detailed networks), a dedicated server or cloud computing environment might be needed to run the model in reasonable time. A key principle for the team is to minimise the introduction of new software/hardware dependencies in Beta, and instead work within existing tools and platforms as much as possible.

This is both to control costs and to ease integration, for example, if NESO already has certain database or cloud infrastructure, we would aim to deploy the FOGSI model there, rather than require a brand-new system. Still, we are evaluating options (like using high-performance computing clusters for large runs, or partitioning the problem to run in parallel) to ensure that technical performance will meet user needs. Any new dependency or technology adopted in Beta will come with a plan for maintenance and support in BAU.

Conclusion

In conclusion, the implementation plan has mapped out a clear route forward for the FOGSI project's outputs. Through engaged collaboration between NGT and NESO, careful consideration of technical and organisational requirements, and a strong focus on training and governance, the project aims to ensure that the innovative modelling tool developed in Alpha will successfully become part of the day-to-day toolkit for future energy system planning. All necessary steps, from securing funding to finalising product ownership, are being addressed so that by the end of Beta, the FOGSI model is not just a prototype, but a fully implementable solution ready for operational use.

Chapter 6: Business Case

Approach

The cost-benefit analysis (CBA) is based on assuming that more effective operation of the future energy system allows for a more efficiently planned system, which in turn leads to small (%) saving on future infrastructure spend.

We assume that, as a result of the project, there is a full national rollout of new operational tools for future integrated hydrogen and electricity systems integrated into the medium to long-term planning processes.

If this is not the case, we anticipate that the future integrated hydrogen and electricity system would be inefficiently operated. This could lead to:

- Insufficient buildout of hydrogen infrastructure compromises energy security, leading to customer disruptions and decreasing energy system reliability.
- Energy security is maintained by relying on dispatchable fossil-fuel generation, compromising net-zero and increasing carbon intensity.
- Alternatively, the lack of appropriate whole-system planning and operational tools leads to an overbuild of hydrogen infrastructure, requiring greater investment upfront, and wasted energy as the system is operated. This would drive up levelised costs (e.g., for green hydrogen) and consumer bills. This could lead to several billions of pounds worth of additional infrastructure needing to be built.

Updates and Assumptions

For the gas system, we have reviewed the gas system costs and assumptions with National Gas, and these remain valid.

For the electricity system, we have assumed that the transmission system design will not change therefore we do not need to incorporate the equivalent electricity systems costs into the cost-benefit analysis. We will review this assumption with NGET as the business case develops, and explore any additional benefits that may arise for the electricity system.

To evaluate the costs, we have included an estimate of the required implementation costs (including software, computation, training, etc). We have assumed that there will be costs associated with these beyond Alpha (and Beta) but that they are similar to the costs for current equivalent tools, with an additional cost of £500,000 a year for systems and staff. This we be re-examined as the business case develops and we consider the implementation and commercialisation plan for Beta and beyond, and will be shaped with input from NG, NGET and any relevant insights from the project’s broader stakeholder engagement activities.

For the assessment, we have updated the inputs using the Holistic Transition scenario from FES 2025 (ref) as the central case. This scenario broadly features a lower volume of hydrogen infrastructure than the previous iteration, which has reduced the benefits calculated. However, with the work in Alpha pivoting to consider the integration of detailed operational models into medium to long term planning process, and the current uncertainty, there is an opportunity for the work developed in the Alpha project to support policy direction and decision making on hydrogen in the short-term.

Timeline

We expect that this will start to generate benefits in the 2030s, once the project is complete and significant volumes of hydrogen infrastructure starts being deployed. However, there is the opportunity for the work to generate benefits sooner than this as it can be used to support policy direction decisions on hydrogen development in the short-term.

Alpha Assessment

Alpha CBA

Figure 44 illustrates the net benefits by confidence level (high in green, medium in yellow and low) over future years. Out of the total lifetime benefits of £329,480,703 this gives lifetime benefits of:

- High confidence: £67,270,231
- Medium confidence: £90,143,381
- Low confidence: £172,067,085.

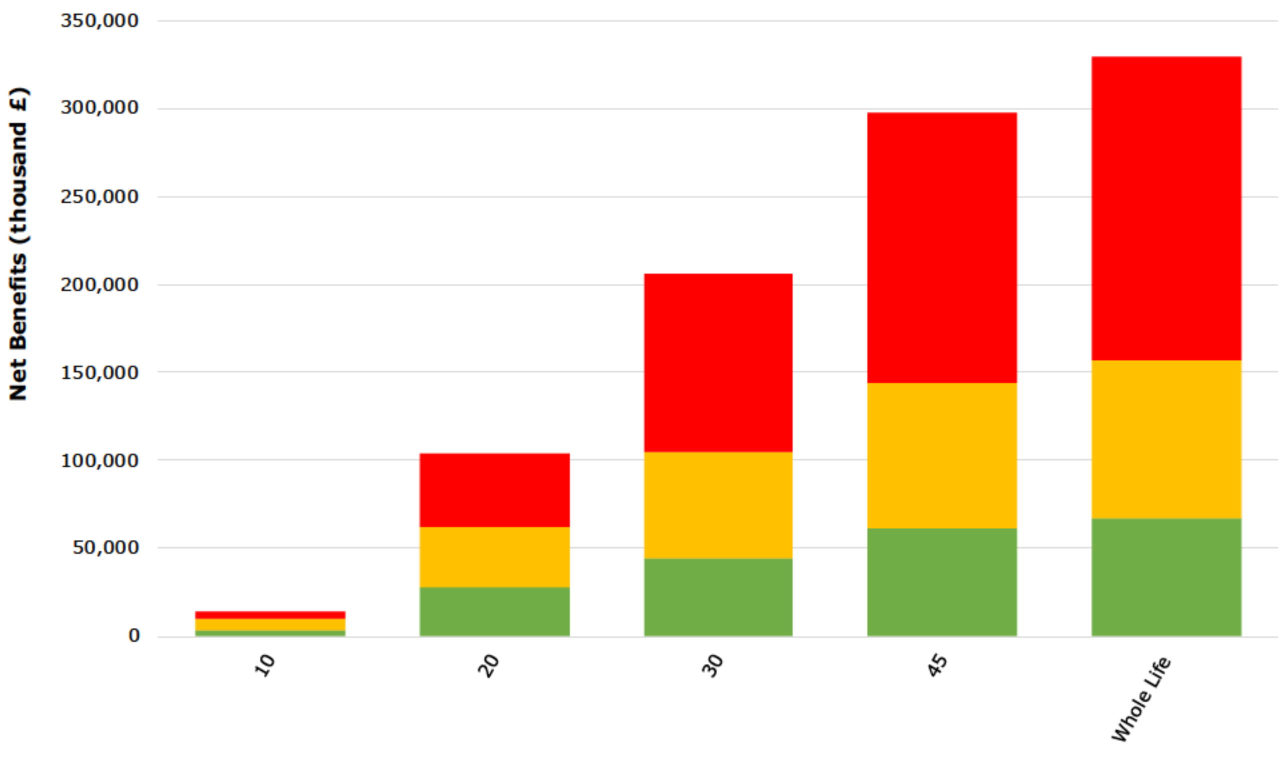

Figure 45 Net Benefits by confidence level (green=high, medium=yellow, low=red)

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

The assessment shows a payback period of 4 years, breaking even in 2030.

Comparison with previous assessments

Although, the overall benefits have reduced in comparison to the earlier assessments, as shown in Figure 45, work in this Alpha project has shown that this work would also support policy direction and decision making for hydrogen infrastructure ahead of detailed planning. Furthermore, high uncertainty over the future of hydrogen infrastructure was a key concern highlighted in the project's stakeholder engagement work. This could mean that even with the uncertainty in the future use of hydrogen in the long-term, continuing the work of this project is beneficial in the short-term as it could support these key decisions.

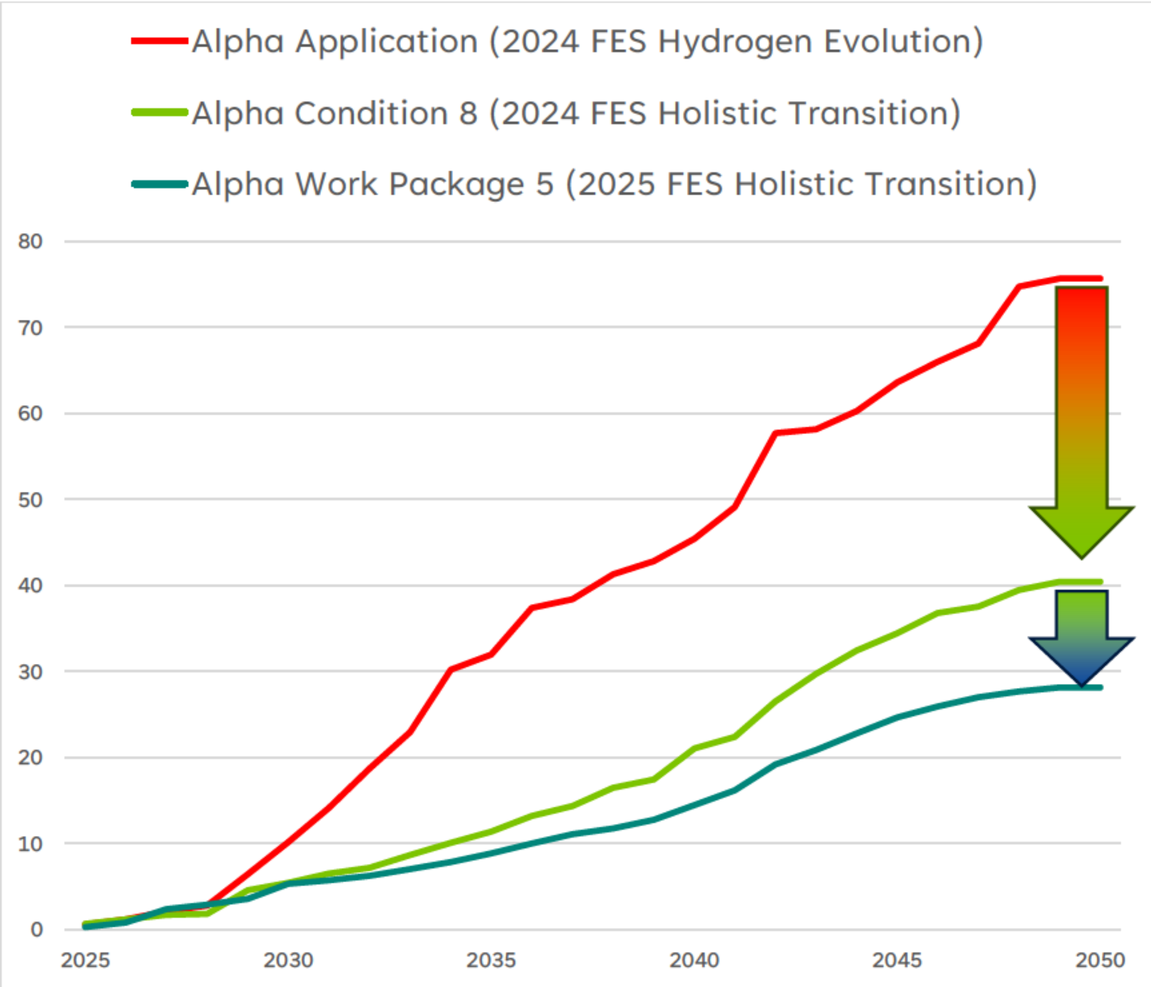

Figure 46 Evolution of CBA results from Discover Application to Alpha Delivery

Conclusion

Concluding remarks

Work in this Alpha project has developed a proof-of-concept model demonstrating the key operational interdependencies between future electricity and hydrogen networks, the assets coupling the networks (electrolysers and hydrogen fuelled thermal generators), and storage. Using this model to explore a set of possible future days with challenging operational conditions has shown a number of interesting results for both future system operation and future planning.

Firstly, we have demonstrated that if the future networks are not operated together, the electricity system will make impossible demands of the hydrogen system. This highlights the risk of relying on planning assumptions based only on aggregate energy balances, as these can overlook the operational limits associated with hydrogen transport, compression, linepack and location-specific deliverability.

Interestingly, when the networks are coupled together, in many cases the national aggregate level picture is very similar – similar outcomes are achieved in terms of, for example, curtailment and electrolysis. However, the optimal (and feasible) timing and location of the decisions is very different. This is an important finding for future planning, as it suggests that apparently similar whole-system outcomes can mask materially different operational requirements and network conditions. This reflects the fact that, once hydrogen network constraints are represented explicitly, the system must respond not only to total demand but also to the timing, location and deliverability of hydrogen across the network. In turn, simplified planning assumptions may understate operational inefficiencies and could lead to over- or under-sizing of assets, where feasibility depends not just on total energy volumes but on when and where flexibility is available.

The results suggest a need for sophisticated real-time control of the gas system. Highly variable flow rates and directions, and compression ratios, are observed across all the days modelled. The model makes quite extensive use of linepack, and while we can meet a fairly generous linepack daily change limit (about 10% of total linepack energy) the spatial distribution of gas changes a lot throughout the day. This results in NG needing to do a lot of work to make sure the system is set up “right” at the start of the day to ensure the system can be operated.

As discussed in Chapter 4, the results for linepack demonstrate significant differences in the state of the system at the start of each example day, as well as significant variation in the spatial distribution of hydrogen. These results only consider single days of operation, and the model has been able to select the initial densities of the gas system for each day, suggesting that it could be considerably more challenging to operate sequential days in the future system. Extending the analysis to longer continuous periods, including prolonged low-renewable and other stress events, will therefore be important in future development to better understand system resilience and storage requirements.

Overall, the results presented in Chapter 4 highlight the complexity of the operational decision making for the future system. However, the model does not yet consider uncertainty in the system and the impact of this on the decision-making processes, which will further increase the complexity of operating the system. Furthermore, additional constraints such as ensuring “N-1” security constraints, having a sufficiently detailed representation of ancillary services, or unit commitment, will introduce additional challenges that will need to be considered. The Alpha results should therefore be understood primarily as a demonstration of the operational interactions that could arise in a future integrated system, rather than as a prediction of a single future operating pattern.

Finally, as highlighted earlier in the report, we have demonstrated the need to incorporate sufficiently detailed operational models into planning processes to plan and build an efficient and effective energy system for the future. Therefore, the direction of the project has pivoted from a purely operational focus, to one where the complexity of operational decision making is incorporated into the processes that support medium- to long-term planning. In practice, this could help improve assumptions used in future planning, inform decisions on the sizing and location of hydrogen infrastructure and storage, and, in time, support more robust assessment of alternative network and investment options across the hydrogen and electricity systems. It also provides important context for the Alpha CBA: while the current inputs are appropriate for an initial proof-of-concept, the findings indicate that future appraisal would benefit from a more comprehensive treatment of operational constraints, longer-duration operation, and cross-network trade-offs.

Beta Direction

The Alpha phase has successfully demonstrated the feasibility and value of integrated gas-electricity modelling through the FOGSI proof-of-concept. Feedback from stakeholders, including DESNZ, NESO, and NGET, has reinforced the importance of refining modelling assumptions, improving spatial granularity, and addressing uncertainty in system operations. These insights have directly informed the Beta phase priorities.

Looking ahead, the Beta phase will focus on advancing the model’s technical sophistication and embedding it within existing planning and operational platforms (e.g. SIMONE software, Collaborative Visual Data Twin (CVDT), Powering Wales Renewably (PWR), Future Control Room). Key developments will include:

- Building robust APIs tailored to licensee needs.
- Integrating with live data environments to support real-time validation.
- Enhancing the model’s ability to handle uncertainty, strategic behaviour, and multi-vector planning.
- Improving the model’s ability to test alternative network constraints, longer-duration stress periods, and explicit cost representations to support more robust investment appraisal and comparison of network options.
- Revisiting and revising the project’s business case, including but not limited to a more detailed exploration of the relationships between the operational scenarios explored here and the impact on investment planning, and any emerging benefits for the electricity network (alongside those already defined for the gas network).
- Defining governance, ownership, and cost models to support long-term BAU transition.

Key Considerations for Beta and BAU

Successful transition of FOGSI from Alpha to BAU will require coordinated action across governance, stakeholder engagement, technical integration, and capability building.

1. [redacted]
3. Beta must prioritise API development and integration with existing tools. Early identification and resolution of technical risks will prevent delays at BAU.
4. A structured training programme is needed to equip NESO and NGT staff with the skills to operate and maintain the model. Documentation, workshops, and cross-domain training will support long-term capability.

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FOGSI - Literature Review Report

UoE - TNEI

October 13, 2025

Contents

The transition to a net-zero energy system necessitates an unprecedented integration of energy vectors, primarily the electricity and gas networks, with hydrogen emerging as a critical medium for energy storage and transmission. To ensure the secure, efficient, and economic operation of this future system, advanced modelling and simulation tools are required. These tools must accurately capture the complex physical dynamics of each network, the operational behaviour of new technologies such as electrolyzers, and the intricate interdependencies that arise at their interfaces.

This document reviews the academic state of the art in modelling of power systems, gas and hydrogen networks, and their integrated operation. Our objective is to establish current capabilities and, crucially, to identify the research gaps that the Future Operability of Gas for System Integration (FOGSI) project aims to address, thereby directly informing FOGSI model requirements and interfaces.

We begin with a synthesis and gap analysis summary that presents the most important limitations of current practice and maps them to specific contributions planned under FOGSI. We then develop the evidence base in six parts: (i) Power System Modelling; (ii) Gas and Hydrogen Network Modelling; (iii) Modelling of Key Coupling Technologies: Electrolysis; (iv) Integrated Gas and Power System Modelling, (v) Analysis of Off-the-Shelf Modelling Tools; and (vi) Review of UK and International Innovation Projects. We close by translating these findings into concrete model requirements and interfaces for FOGSI.

1 Synthesis and Gap Analysis Summary

This review shows a mature literature for stand-alone power and gas systems. Significant gaps, however, persist for deeply integrated operation under large-scale hydrogen adoption and weather-driven variability. FOGSI is designed to target these specific shortcomings, summarized in Table 1.

- **Fidelity–Scalability & Feasibility.** Integrated studies commonly pair DCOPF with steady-state or time-linked gas models (e.g., linepack proxies), which cannot represent the full transient gas behaviour (e.g., linepack dynamics, compressor/valve effects) needed for intra-day feasibility [12, 17]. At the other end of the spectrum, high-fidelity transient gas models with realistic station/valve logic exhibit long runtimes at realistic scales (e.g., 24 h horizons on ∼500-node networks) [37]. Multi-rate co-simulation confirms the disparate timescales (hourly power; minutes–hours gas) but, being simulation-oriented, does not provide optimization-performance guarantees [52].

  FOGSI contribution: Combine established approaches and create more accurate, scalable models bringing operational power models together with calibrated transient gas representations, to better capture gas–power interactions while remaining tractable for GB-relevant studies.

- **Relaxations can overstate linepack flexibility.** Linear/conic relaxations of gas physics (e.g., linearised/SOC Weymouth, linepack proxies) improve tractability but can be loose, yielding bounds rather than feasible operating schedules and permitting unrealistically fast linepack charge/discharge, thus overstating flexibility [54, 56].

  FOGSI contribution: Design and calibrate physics-aware surrogates with tightened envelopes, physics-consistency checks (feasibility recovery, gap metrics), and validation against transient models.

- **Uncertainty in tightly coupled, dynamic systems.** While uncertainty is well treated on the power side, very few works combine nonlinear, transient gas with uncertainty, especially supply-side uncertainty from renewables-to-electrolysis [17, 63]. Demand uncertainty with transient gas is treated in small cases [63]; most distributed, robust, or chance-constrained formulations either omit gas transients or simplify flows (e.g., static Weymouth, linearized power) [15, 19, 57].

  FOGSI contribution: Build weather-driven GB scenarios with explicit electrolysis-supply uncertainty and propagate them through the coupled gas–power interface—using transient gas where feasible and calibrated approximations otherwise.

- **Coupling points beyond gas-fired generation and coordinating timescales.** Operational models often focus on GFPP; fewer represent electric-driven compressors, LNG/UGS power dependencies, or P2G in operations; blend tracking appears without compressor models; methods to coordinate hourly

Table 1: Concise summary of key gaps identified based on the academic literature and FOGSI focus areas (selected evidence).

Key gap	**FOGSI focus**
Fidelity vs. scalability (simple DC power + steady-state gas models can be fast but miss transients; fully transient gas models are accurate but too slow at realistic scale) [12, 17, 37, 52]	Combine established approaches and create more accurate, scalable models by coupling operational power dispatch models with calibrated transient gas representations, aiming to preserve feasibility while remaining tractable on GB-relevant cases.
Relaxations may overstate linepack flexibility (yield bounds rather than feasible schedules and can allow unrealistically fast charge/discharge) [54, 56]	Design and calibrate physics-aware surrogates with tightened envelopes and post-solve feasibility checks, validated against transient models.
Uncertainty in tightly coupled, dynamic systems (few works combine nonlinear, transient gas with uncertainty, especially supply-side renewables-to-electrolysis; most stochastic approaches omit transients or simplify flows) [15, 17, 19, 57, 63]	Build weather-driven GB scenarios with explicit electrolysis-supply uncertainty and propagate them through the coupled gas–power interface, using transient gas where feasible and calibrated approximations otherwise.
Non-GFPP couplings and timescale coordination under-developed (electric-driven compressors, LNG/UGS power dependencies, P2G often omitted; limited methods to align hourly power with slower gas dynamics) [15, 17, 44, 52, 65]	Represent GFPP, electric-driven compressors, LNG/UGS power dependencies, and P2G/blending within a scalable framework, and evaluate ways to coordinate hourly power scheduling with minute-to-hour gas dynamics on GB-relevant cases.
High-fidelity electrolyzer and storage physics underused at system scale (non-constant efficiency with thermal/electronics losses; density-dependent withdrawal) [22, 36]	Develop tractable non-constant electrolyzer surrogates and include physics-based storage constraints in system-level studies, calibrated against device-level models.
Validation, benchmarks, and GB readiness [12, 24, 41, 44, 52, 62, 66, 67]	Curate GB-relevant scenario datasets and build reproducible pipelines from planning to dispatch to transient verification; benchmark against public test systems.

power scheduling with minute-to-hour gas dynamics remain under-developed [15, 17, 44, 52, 65].

FOGSI contribution: Represent GFPP, electric-driven compressors, LNG/UGS power dependencies, and P2G/blending within a scalable framework, and evaluate ways to coordinate hourly power scheduling with minute-to-hour gas dynamics on GB-relevant cases.

- **Integration of high-fidelity component models.** Detailed electrolyzer models (non-constant efficiency with thermal dynamics and power-electronics losses) and physics-based storage (density-dependent withdrawal) are rarely embedded in large-scale, dynamic, integrated studies [22, 36].

  FOGSI contribution: Develop tractable non-constant electrolyser surrogates (e.g., piecewise-affine with thermal/ramp limits) and include physics-based storage constraints in system-level models, calibrated against device-level references.

- **Validation, benchmarks, and GB readiness.** Case scales range from IEEE 24-bus + Belgian 20-node [14] and IEEE 39-bus + a Belgian gas network [66] to IEEE RTS-96 + a 24-pipe benchmark gas system [67], GB 16-bus + gas [12], and European regional systems [52]; co-simulation tooling exists (e.g., IEEE-300 + GasLib-134) [24]. Planning reviews emphasize DC power and simplified gas in long-term studies [41, 44, 62].

  FOGSI contribution: Curate GB-relevant scenario datasets and build reproducible pipelines from planning to dispatch to transient verification; benchmark against public test systems.

Additional gaps identified from the review of innovation projects are summarized in Table 2; details can be found in Section 7.

Table 2: Additional gaps identified from the review of GB licensee innovation projects.

Key gap	**FOGSI focus**
Innovation projects focus on local planning or stakeholder behaviour, lacking a unified national transmission model.	Develop a holistic, physics-aware operational model for the national transmission system to assess system-wide impacts and trade-offs.
Scenario-building projects neglect the detailed operational feasibility and control strategies needed to manage extreme events.	Test the operational viability of future energy scenarios, especially under extreme conditions, by generating robust, coordinated control actions.
Digital twin projects focus on data and visualization, not integrated operational optimization.	*(Future)* Embed the optimization tool within a digital twin framework to enable automated, forward-looking operational planning.

2 Power System Modelling

The optimization and operation of power systems is a mature field of study. Modern grids, however, are evolving from centralized, one-way structures into highly dynamic, decentralized systems accommodating new technologies, market structures, and environmental constraints.

2.1 Core Formulations and Extensions

The foundational model for power system optimization is the Optimal Power Flow (OPF), introduced by Carpentier [11], which minimizes operating cost subject to AC power-flow physics and engineering limits. Over the decades, OPF has become a building block for more complex models. For example,

- Security-Constrained OPF (SCOPF): Ensures the system remains stable even after credible contingencies, such as the failure of a major line or generator (typically $N-1$ security).

- Unit Commitment (UC): Fundamental to day-ahead and real-time markets; augments OPF with binary on/off decisions for generation units, alongside inter-temporal constraints like ramping limits, minimum up/down times, and start-up/shutdown costs [25].

Higher-level operations include topology control and switching [4, 38], voltage control and stability enforcement [47], while long-term planning integrates generation and transmission expansion with demand response and storage [51].

In practice, problems span multiple time horizons: real-time balancing (seconds–minutes), short-term scheduling and UC (hours–day), medium-term scheduling with intertemporal dynamics, and long-term expansion and investment (months–years) [25, 51].

2.2 Modelling Uncertainty

Uncertainty from load fluctuations, variable renewable output, and market prices is addressed through:

- Stochastic programming: Represents uncertainty through a set of discrete scenarios with associated probabilities and creates a scenario-based formulation; scenario reduction is usually employed for tractability.

- Robust optimization: Protects against the worst-case deviation within a defined uncertainty set (e.g., budgeted, polyhedral, ellipsoidal), offering a more conservative guarantee of security.

- Chance-constrained programming: Enforces system constraints with a prescribed high probability, allowing for a small, controlled risk of violation.

A detailed survey of these approaches as applied to OPF under uncertainty can be found in [51].

2.3 Computational Complexity and Formulations

Most comprehensive power system optimization problems are formulated as large-scale, nonconvex problems. The full AC Optimal Power Flow (ACOPF) is a smooth but nonconvex Nonlinear Program (NLP); hence, global optimality cannot generally be guaranteed. Adding discrete decisions (UC, line switching, expansion) increases the complexity, making the problem a Mixed-Integer Nonlinear Program (MINLP). To achieve tractability, simplified models are widely employed:

- DC Optimal Power Flow (DCOPF) is a linear program (LP) that trades physical fidelity for speed; with UC binaries and network constraints, it becomes a Mixed-Integer Linear Program (MILP).

- Convex relaxations of AC power flow (e.g., semidefinite, second-order cone, and quadratically constrained relaxations) provide bounds and can be exact on certain networks/operating points [4, 50].

2.4 Solution Methods and Test Systems

Solution methods fall into two broad categories:

- Deterministic mathematical programming approaches dominate: interior-point and sequential quadratic programming methods for continuous OPF; branch-and-bound/branch-and-cut for MILPs; and decomposition methods for large-scale UC [26].

- Metaheuristic approaches, such as genetic algorithms, swarm optimization, simulated annealing, and hybrids, are used when highly nonconvex or discrete structures render exact methods impractical [27].

Studies commonly use IEEE test cases [31] or larger datasets like those from [43], while several papers focus specifically on the Great Britain power system, either on its own or in combination with the gas network [9, 13, 53].

3 Gas and Hydrogen Network Modelling

Modelling compressible flows (natural gas, hydrogen) on transmission networks is fundamentally complex. State-of-the-art formulations descend from the Euler equations; Brouwer et al. [7] derive hierarchies of Partial Differential Equation (PDE) models (non-isothermal/isothermal), with (discretizations of) the friction-dominated isothermal model the common choice in network studies. Surveys cover modeling choices (e.g., physical laws, network elements, coupling conditions at junctions, active vs passive elements) as well as transient and PDE-based models, address key topics such as well-posedness, controllability, feedback stabilization, inclusion of uncertainty, and numerical methods, and situate PDE-constrained optimization on graphs within this broader framework [28, 32, 55].

3.1 Model Fidelity vs. Tractability

A central challenge in gas network optimization is the trade-off between physical fidelity and computational tractability [55].

- Nonlinear transient (PDE-based) models: Discretizations of the (typically isothermal, friction-dominated) Euler equations capture pressures, transients, and linepack, and can include compressors, compressor stations, storage and valves. They offer high physical fidelity but lead to large, nonconvex formulations (and integrality when valves/station logic are present) [2, 36, 37, 42, 49, 63].
- Linearized/simplified models: To gain tractability, many works approximate the momentum equation (linear or piecewise-linear) and represent compressor operating regions with polyhedral/convex-hull envelopes, yielding MILP models that scale to larger networks and longer horizons [29, 30, 39]. These abstractions improve tractability but reduce dynamic fidelity (notably for linepack and transient feasibility). The limits of purely stationary abstractions for intra-day operations are documented in [3].
- Stationary/steady-state models: For steady-state operations, planning, and value-chain modelling, where tractability is prioritized over transient fidelity, see [17, 34, 35, 58]; these are useful baselines but do not represent instationary feasibility needed for intra-day studies.

3.2 Modelling Key Components

- Compressors and compressor stations: From simple compressor maps with continuous variables [10, 49] to complex station/regulator/valve assemblies requiring binaries and nonconvex envelopes [33, 37]; higher fidelity improves operability but increases combinatorics.
- Storage: "Battery-like" abstractions miss reservoir physics (density-dependent withdrawal). Hari et al. [36] show these effects are critical for small reservoirs relative to network capacity/horizon.
- Valves and switching: Binary controllable elements essential for feasible transient operations, often co-modelled with compressors.
- Gas quality and mixing: Tracking blends and quality indices introduces additional state variables and coupling constraints; still under-researched in transient optimization, yet pivotal for hydrogen transition and (de)blending. Steady-state flows for blending are simpler, but still non-trivial [6, 60]. Parameterization of the speed of sound in gas blends via experiments is not yet thoroughly explored [21].

3.3 Modelling Uncertainty

Stochastic/transient co-optimization is relatively rare. Zavala [63] treats demand uncertainty with transient gas dynamics (no integers), but there is a notable gap in models that couple nonlinear, transient gas with supply-side uncertainty, as would arise from renewables-to-electrolysis driven hydrogen production, which is central for future GB scenarios.

3.4 Solution Methods and Test Systems

- Nonlinear/transient NLPs (PDE-based): They are usually solved via interior-point/SQP on small to medium networks or with reduced horizons/time steps. Some examples are as follows:
  - Very small, detailed simulations: 4 nodes and 5 arcs with compressor characteristics [42].
  - Medium networks with restricted complexity: GL40/GL135, 25 time points over 24 h, fixed flow directions, no valves; discussion of discretisation trade-offs in complexity/accuracy/runtime [49].
  - Small stochastic cases: 13 nodes, 12 arcs, 10 compressors, $\Delta t = 30$ min, $\Delta x = 1/10$ pipe length (demand uncertainty) [63].
  - Very large transient cases with storage physics: 506 junctions, 20 compressors, 4 storage units, 196 sources/sinks, 24 h with $\Delta t = 1$ h; non-horizontal pipes allowed [36].
  - Large networks with complex station/valve logic: 477 nodes and 531 arcs, 24 h horizons with reported solution times up to a day [37].
  - MPEC-style frictions/operating regions: 30 nodes (3 sources, 15 sinks), 100 time periods, 0.7–3.2 km pipes; fixed compressor efficiency [2].
- Mixed-integer approximations: Linear/piecewise-linear momentum plus polyhedral/convex-hull compressor regions; often with decomposition across time:
  - 29 pipes (50–200 km), 4 compressor stations, 24 h with $\Delta t = 30$ min on a cyclic network; $\sim$1.25 h to 5% MIP gap [30].
  - 179 nodes, 200+ arcs with local "network stations" for detailed compressor/regulator models (tri-level MINLP) [39].
  - 112 pipes, 9 compressor stations, 16 valves over 12 h with $\Delta t = 1$ h; decomposition master with simplified friction/station models [29].
- Hybrid/other:
  - Instantaneous control heuristic (time-marching feasibility restoration): 17-arc network, $\Delta x = 1/10$ pipe length, $\Delta t = 1$ min, 3 h window; generally sub-optimal [33].
  - Finite-volume discretisation with global optimisation on small networks: GL11, 8 h window, $\Delta t = 10$ min, $\Delta x = 1/2$ pipe length; sequence of MIPs to an ε-feasible global solution [10].

4 Modelling of Key Coupling Technologies: Electrolysis

Electrolyzers are the principal coupling technology between power and hydrogen networks; their operational characteristics determine conversion efficiency, flexibility, and ancillary services.

- Component-level modelling: Detailed models capture nonlinear conversion efficiency (power-dependent, temperature-dependent), AC/DC conversion losses, thermal dynamics, and overload limits. In a PEM context for a hydrogen refuelling station, Flamm et al. [22] minimize production cost while fitting piecewise-affine efficiency curves from experimental data; stack temperature dynamics are approximated linearly, the cooling system is simplified (three phases neglected), and power-electronics losses are included.
- System-level impact: Large electrolysis plants can provide fast frequency support and flexibility to the grid. Tuinema et al. [59] build a simulation-only model (no cost/market objective) covering the stack, conversion stage, and balance-of-plant, calibrate ramp behaviour to test data, and simulate response on a northern Netherlands transmission model, reporting faster response than conventional generators.
- Landscape review: A broad survey of electrolyzer technologies, control strategies, and safety/environmental considerations is provided in [1].

5 Integrated Gas and Power System Modelling

Combining gas and electricity network models introduces bidirectional dependencies and the need to align disparate operational timescales. Electricity reacts on seconds–minutes and is dispatched hourly (e.g., unit commitment), while gas hydraulics evolve on minutes–hours, with linepack and compressor dynamics creating significant memory across time [12, 52]. How these layers are coupled has major implications for system feasibility, optimality, and computational tractability [15, 17].

5.1 Common Modelling Approaches and Simplifications

To maintain tractability, most integrated models simplify the physics of at least one system, a trade-off that is a recurring theme in the literature.

- Electricity Network: A lossless DC Optimal Power Flow (DCOPF) or a linearized dispatch model is the standard simplification, used in early foundational work and many modern studies to avoid the nonconvexity of AC power flow equations [5, 12, 44, 56].
- Gas Network: Models often use a steady-state representation (e.g., the Weymouth equations) or simplified transient models with aggregate linepack proxies [12, 19, 56].

A canonical example is the coupling of DC power with a simplified, time-linked gas model, which captures the core dependency of gas-fired generators but can struggle with dynamic feasibility [12, 17]. Reviews highlight the significant scalability challenges of combining fully transient gas models with operational electricity models on realistic networks [15, 16, 17]. Crucially, recent analysis shows that convex relaxation–based approaches can be physically misleading, overestimating flexibility from linepack by allowing infeasibly high charge/discharge rates [54].

5.2 A Spectrum of Integration Approaches

The literature showcases a range of coupling strategies, from loose co-simulation to tightly integrated co-optimization.

- Iterative simulation / co-scheduling: Each network operator solves its own problem and exchanges boundary information (e.g., gas demand from power, electricity availability for compressors) iteratively. This mimics real-world operational separation. [52] couple a detailed AC-OPF (MATPOWER) with a transient gas simulator featuring compressors, LNG, and underground storage, using multi-rate time steps (hourly for power, adaptive for gas). Optimize–then–simulate loops also appear in day-ahead settings, with a linear boundary-optimization followed by full nonlinear simulation and iterative constraint enrichment until convergence [65]. While realistic, these approaches may yield suboptimal or system-wide infeasible results [17].
- Distributed optimization: Decomposition methods solve separate network problems in parallel while coordinating on coupling variables. Analytical Target Cascading (ATC) is used for coupled electricity–gas and transmission–distribution problems with linearised flow models; e.g., DistFlow power + static Weymouth gas (no compressors) with linearised chance constraints for wind uncertainty [19], and decentralized ATC with piecewise-linear Weymouth in multi-energy UC/dispatch [64].
- Monolithic co-optimization. A single, large-scale optimization (NLP/MINLP or a convex relaxation) captures both networks and coupling constraints simultaneously. [67] demonstrate the benefits of fully dynamic, gas-aware co-optimization relative to the status quo. To manage hardness, some works employ convexification (e.g., MISOCP relaxations for linepack and bidirectional flows via quadratic convexification and McCormick envelopes [56]); others expose a static gas feasibility envelope to the AC/DC power problem [18]; or reformulate bidirectional Weymouth physics via MPCC to avoid binaries [5]. Continuous time–space formulations with transient gas and lossless DC power have also been recast to MILP and validated via simulation [66].

- Market and equilibrium models. Strategic behaviour across coupled markets is analyzed with bilevel/MPEC constructs. [14] derive equilibria with strategic bids, linearised power flow, and SOC-based gas constraints (fixed flow direction), while [20] study a Cournot–Nash model for coupled hydrogen and electricity markets (DC flow ensures equilibrium existence under certain losses). [17] provide a taxonomy covering operations, planning, and equilibrium.

- Planning and multi-vector extensions. Reviews classify operational analysis, optimal dispatch, and optimal planning, stressing the role of P2G, storage, and linepack for flexibility [41, 44]. Examples include 10-year investment in electrolysers and seasonal storage (hydrogen by trucks) [46], wind–H_2–gas planning with blending and transport-mode choices [61], and a three-layer pan-European transition workflow through 2050 (linear investment; MILP UC feasibility; AC/MINLP operational feasibility) [62].

5.3 Uncertainty, Hydrogen, and New Technologies

- Uncertainty: Handling uncertainty from renewables and demand is a key driver for integration. Approaches include robust formulations with interval uncertainty (e.g., wind/solar in GVPP dispatch) [57] and linearised chance constraints for wind forecast errors in distributed settings [19]. Large-scale stochastic formulations and suitable decompositions are surveyed in [15, 17].

- Power-to-Gas (P2G) and Hydrogen Blending: P2G is a critical coupling technology to absorb curtailed renewables; its role in planning/operations is reviewed in [44]. Operational frameworks with gas-blend tracking (H_2/SNG injections) highlight modelling and feasibility challenges at the gas–power interface [65].

- New solution paradigms: Data-driven control/optimization appears in recent work; e.g., deep reinforcement learning for multi-objective operation in integrated systems (with simplified physics and a single planner) [45].

5.4 Solution Methods and Test Systems

- Nonlinear Programming (NLP) / Optimal Control: Dynamic gas flow coupled with DC dispatch solved via interior-point/SQP; fully dynamic cases can take around an hour on modest tests [67]. Continuous spatial–temporal formulations preserving PDE characteristics can be reformulated as MILP and validated by simulation [66].

- Mixed-Integer Convex/Linear Programming (MICP/MILP): Piecewise-linear momentum/flow and convex envelopes yield faster models, but can be optimistic about flexibility; MISOCP relaxations (steady-state gas with linepack, bidirectional flow) may be loose and require feasibility recovery [56], and relaxation choices can overstate linepack charge/discharge rates [54].

- Specialized formulations: Distributed optimization via ATC/parallel MILPs (DistFlow + static Weymouth; no compressors; linearised chance constraints) [19]; decentralized ATC with piecewise-linear Weymouth in multi-energy dispatch [64]; MPCC formulations for bidirectional Weymouth without binaries [5].

- Common test systems: IEEE 24/39 buses + Belgian 20/31-node gas, RTS-96 + benchmark gas [66, 67]; GB simplified 16-bus + gas [12]; European regional case with 158 buses, 62 generators, 194 lines, 345 pipes, 10 compressor stations, 352 nodes [52]; Colombia (96-bus power; 63-node gas with 13 wells, 48 pipelines, 14 compressor stations) [5]; and wind–H_2–gas cases in China (15 wind farms; 10 gas nodes) [61]. Co-simulation on IEEE-300 + GasLib-134 (1 compressor + control valve) shows gas optimizations under a minute [24].

6 Analysis of Off-the-Shelf Modelling Tools

A number of open-source, academic modelling frameworks are available to facilitate the analysis of energy systems. These tools are typically formulated as (mixed-integer) linear optimization problems and adopt a central planner perspective, assuming perfect foresight to determine cost-optimal investment and dispatch strategies for a single energy vector or a local, integrated system.

- Continental Power System Planning (PyPSA): The PyPSA (Python for Power System Analysis) ecosystem provides a free software toolbox for both operational simulation and long-term investment planning for electrical power systems, using a linear problem formulation [8]. The flagship application, PyPSA-Eur, offers a concrete, open model of the European transmission system covering the entire ENTSO-E area. Its continental scope and high resolution are designed to capture the long-range smoothing effects of renewable generation. The model optimizes from the perspective of a single benevolent social planner to determine optimal system expansion and operation over a given year [40].

- Continental Gas System Planning (GNOME): For the natural gas sector, the Gas Network Optimisation Model for Europe (GNOME) was developed to address a gap in sufficiently detailed public models for analyzing supply/demand dynamics and infrastructure investment. It is a dynamic, highly granular mixed-integer linear optimization model of the European gas network, including its exogenous suppliers (e.g., Qatar and Nigeria). From a central planner perspective, it generates cost-minimal dispatch and investment strategies across indigenous production, pipeline flows, LNG imports, and storage, operating on a monthly basis in five-year steps from 2025 to 2040 [48].

- Local Multi-Energy System Design (DRAF): At the local level, the Demand Response Analysis Framework (DRAF) is an open-source tool for optimizing the design and operation of local multi-energy systems (L-MESs). It focuses on quantifying the cost and emission reduction potential from integrating demand-side flexibility, electrification, and renewables in industrial and commercial settings. While it does not simulate market interactions between competing agents, its central planner makes decisions based on deterministic day-ahead market prices [23].

7 Review of GB Licensee Innovation Projects

This section presents the results of a comprehensive review of current and past GB energy network licensee-lead innovation projects, i.e. NIA projects and the three stages of SIF projects. The main objectives of this review are to: (i) demonstrate the uniqueness of the optimisation approach proposed in this project; (ii) identify which projects likely contain learnings that should be considered in this project – which may not be directly related in theme; (iii) identify live projects working on connected themes where direct communication between researchers would be beneficial; (iv) identify live and recently completed projects where a progression of some aspects of the work would add value to a Beta phase of this project.

Information about the projects was sourced entirely from the Smarter Networks Portal (https://smarter.energynetworks.org/), with the exception of the most recent projects lead by the gas network licensees, where the information is located on the Future Energy Networks portal (https://portal.futureenergynetworks.org.uk/).

It should be noted that when it is reported here that a project is e.g. a live SIF Beta, it should be taken as given that there were also preceding Alpha and Discovery projects with similar names, now completed, that are not mentioned for the purpose of brevity.

7.1 Optimisation and Intelligent Control Systems

The FOGSI project is about controlling integrated electricity and gas networks by solving a hierarchical network of optimisation problems that explicitly consider uncertainties on several different time scales and locations. This first subsection of the review covers projects that investigated similar topics, with control either through optimisation or machine learning and other types of AI.

The most significant, due to its size and being live, is the SIF Beta project *Intelligent Gas Grid*, which is developing and trialling the use of data-driven ML & AI techniques, when combined with remote pressure control and network extremity monitoring for managing pressure in gas distribution networks (GDNs), forming a distributed digitalised architecture. A similar live NIA project but applied to DNOs is *A Holistic Intelligent Control System for Flexible Technologies* (actually two NIAs: *Part 2* is now live, and *Part 1* is completed) – the goal in this case being optimised HV and LV voltage profiles.

A particularly interesting live NIA project is *GPU Accelerated Grid Optimisation*, led by NESO, which is tasked with developing an optimisation solver that leverages GPU acceleration to improve speed, accuracy, and scalability. The project summary states that solving large-scale optimisation problems, such as whole energy system optimisation, might be impossible to complete within a reasonable time using current CPU-based solvers, and that the solution is to employ the parallel processing capabilities of GPUs. It would certainly be very useful to learn about the modelling assumptions, optimisation problem framing and solution methods that are being explored in this project, and compare with our adopted choices.

7.2 Enhanced Control Rooms

If implementing a hierarchical ecosystem of coupled optimisation problem solvers, i.e. the ultimate goal for this project, then questions naturally arise about the nature of the interface with control room engineers, and how it could be integrated into control room processes in a way that guarantees stronger support for good decision making. This is particularly true when considering the system of solvers as an online tool, rather than in offline simulation mode to aid planning scale decisions. It was therefore relevant to examine recent projects that were concerned with exploring possibilities for enhanced future control rooms, for both gas and electricity networks.

It was found that there is a currently live NIA project, led by NESO, that is highly relevant: *Volta: Grand Optimiser Design Philosophy*. This project aims to lay out the design principles for a whole system balancing optimisation engine, based on security constrained economic dispatch, which includes consideration of good strategic directions for the evolution of (transmission level) control room processes. It seeks to understand how to transform a wider whole energy system perspective into a more comprehensive and systematic balancing process. While this approach will surely bring benefits, it may be the case that the technical innovations in the optimisation engine would still represent incremental improvements to the electrical network problem rather than this project's more radical proposal of assigning equal importance to the electrical and gas network problems.

Another 3 relevant projects conducted over the last few years were found, all of which are essentially digital twin simulation environments that place a strong emphasis on presentation to and interaction with control room engineers. One project is *Trinity*, which was a UKPN-led SIF Alpha project that was completed in 2024. It aimed to improve DNO resilience by implementing and testing of parallel control room simulation environments, and therefore shared one of the two ultimate goals of our project, albeit on the level of electrical distribution networks only.

The NIA project *Future Control Room* was also concerned with DNO control rooms – describing itself as concerned with the requirements and benefits of a future electrical control room simulated environment. Finally, the NIA project *Gas Control System: Impact Assessment (Future Requirements)* was concerned with developing the networks' understanding of the system operators' future needs and data requirements, topics that are certainly relevant to this project.

7.3 Digital Twins

The primary goal of this project, which would be realised to a much greater extent in a Beta project, is to simulate the sequential decision making of a benign central planner that controls each interconnected energy network (electricity and multiple gas networks), given imperfect forecasts of weather-driven generation availability and demands. To be ultimately valuable, the decision making must be demonstrated within a rigorous representation of a set of realistic networks – i.e. an ecosystem of digital twins.

While many of the projects mentioned in the previous subsection were digital twins with a focus on enhanced control room processes and environments, this subsection examines the extent to which digital twins more broadly are an active area of research among the SIF and NIA projects. It also examines whether the current research questions regarding digital twins overlap with, or are complementary to this project. The simple answer to the first question is that the development of digital twins is indeed a very active area of research, with four currently live SIF Beta projects and one live SIF Discovery projects. There are also many recently completed SIF Alpha and Discovery projects and NIA projects.

The live Beta projects are the following:

- *Planning Regional Infrastructure in a Digital Environment (PRIDE).* This involved both electrical and gas network digital twins, and follows from Discovery and Alpha projects of the same name. It is concerned with exploring novel governance structures for digital twins created by different companies/organisations, combined with a digital tool for collaboration to achieve local and regional decarbonisation.

- *Climate Resilience Decision Optimiser (CREDO+).* This also involved both electrical and gas network digital twins, and follows from very similarly named Discovery and Alpha projects. It describes itself as a 'resilience demonstrator' that operates within a digital twin and data sharing platform named the Climate Resilience Decision Optimiser. This one is particularly relevant to FOGSI, since we are interested in what optimal decisions look like in extreme conditions such as a long period of cold, calm and overcast conditions that may be about to lift, according to a highly uncertain forecast.

- *Predictive Safety Interventions.* This is a project involving a digital twin framework for GDNs only (again preceded by closely aligned Discovery and Alpha projects). It is concerned with data-led operational management to drive improved safety and productivity, and is already being used to make better scheduling decisions.

- *Powering Wales Renewably.* This has been a fairly high-profile sequence of SIF projects, with a scope encompassing electricity transmission and distribution networks. It is concerned with the ability to utilise an ecosystem of transmission and distribution network digital twins to make superior regionally coordinated decisions on planning time scales to facilitate a rapid transition to a renewable generation powered system.

There is one additional live project – the *EN-twin-e* SIF Discovery project. It is concerned with establishing the minimum viable product technical criteria for integrated electricity transmission and distribution digital twins.

Regarding the completed projects, one NIA project was named *Data Sharing Protocols*, and researched common data sharing structures between DNOs and GDNs, seeking to improve mutual understanding both network types develop and respond to operational plans, covering a 24–72-hour period. This makes the project relevant, since generating such plans is the objective of the optimisation problem at the heart of our project.

Another completed NIA project was named *Digital Twins: Exploring the Commercial, Societal and Operational Benefits of Green Hydrogen Projects*, which promoted a "data first" approach to hydrogen planning using digital twins – linking power, water, and gas data infrastructure. The SIF Discovery project *Tyseley Environmental Enterprise District (TEED)* explored the use of a digital twin to deliver a mixed-vector energy system with integrated energy storage in a specific district.

On the purely gas side, the SIF Discovery project *Gas Networks Interoperable Digital Twin* developed a cooperative digital strategy utilising digital twins to optimise existing assets and improve future systems designs. Also, the SIF Alpha project *Gas System of the Future Digital Twin* promoted a vision for a unified 'gas system of the future' digital twin within a distribution network transporting both hydrogen and natural gas.

An interesting sub-category of digital twin projects are those described as 'visual data twins', which place an emphasis on being easily interpretable by visualising results. Two projects in this category are a sequential pair of recently completed NIA projects named *Collaborative Visual Data Twin: Phase 1* and *Collaborative Visual Data Twin: Phase 2*. The former describes itself as investigating an interactive and collaborative digital twin for the transportation of hydrogen. The latter describes itself as connecting into historic and live databases and virtual network models to obtain insights required by digital twin use cases. Finally, the recently completed SIF Discovery project *Rapid Evaluation Areal Connection Tool (REACT)* explored the potential for a geographic visualisation planning tool helping stakeholders navigate the complexities of network upgrading for net zero.

The final sub-type of relevant recent digital twin projects are those that describe themselves as exploring the creation of 'Virtual Energy Systems'. The first project is simply titled *Virtual Energy System (VirtualES)*, and was a SIF Discovery project that ambitiously envisioned an industry-wide initiative to develop a digital twin of the "entire GB energy system" – although that likely didn't extend to transmission and distribution networks for electricity and hydrogen, natural gas and CO2 networks.

The next was a NIA project named *A Common Framework for a Virtual Energy System*, that described itself as exploring a virtual energy system digital twin of the GB energy system aimed at improving data driven decision making. This has, in a sense, the opposite purpose to the tools investigated in our project, since it is about allowing control room engineers to make semi-subjective decisions rather than treating uncertainties in a mathematically optimum way.

Another project in this category was the NIA project *Virtual Energy System: Data Sharing Infrastructure (DSI) Pilot: SSEN-T Component*, concerned with the creation of a scalable common data sharing infrastructure for an ecosystem of connected digital twins. Similarly, the NIA project *Virtual Energy System: Common Framework Demonstrator* had the goal of developing and demonstrating a framework for creating an eco-system of digital twins.

Overall, it can be summarised that the live and recent projects are essentially concerned with practical matters relating to the gathering, processing and exchange of data – and not at all with solving optimisation problems. The slight exception are those projects primarily concerned with visualising this data. These projects represent aspects of the learning necessary to create high quality and detailed digital twin ecosystems that are non-overlapping with our project, yet equally necessary. These very different threads must ultimately be integrated to deliver truly useful simulations involving realistic networks as well as realistic complex decision making under uncertainty.

7.4 Local/Regional Integrated Energy Planning

A fairly popular theme among recent and current innovation projects that is closely related to the smaller-scale digital twin projects is that of integrated energy planning on regional and local scales. Indeed, many digital twin projects were motivated by the identified need for such integrated planning, but not all such projects fit into the digital twin category. Those that do not are presented in this section.

There are two live NIA projects in this category, the first being *Regional Energy System Optimisation Planning (RESOP)*, which is developing digital tools for Local Area Energy Plans and Local Heat and Energy Efficiency Strategies, using the knowledge of varied subject matter experts. The other is named *Navigator Project*, which is developing a Whole Energy Systems Pathway (WESP) tool for GDNs, with spatiotemporal investment planning capabilities.

The first of two completed SIF project in this category is named *Whole Energy System Network Planning Review* and is examining options for the national Future System Operator to ensure that more effective strategic network planning performed in a whole energy system way, that can significantly lower the costs of the net zero transition. The other, named *Energy Plan Translator*, developed a toolset for the rapid analysis of local area energy plans, converting qualitative statements to quantified metrics and parameters – a very interesting statistical endeavour.

Two completed projects were engaged with the concept of energy hubs: co-located, integrated energy system components that can combine multiple energy sources, converters, and storage solutions to potentially produce, convert, store, and supply various energy carriers like electricity, hydrogen, and heat. That is, they represent potentially complex couplings between energy networks that may need to be represented in future models to which the FOGSI solvers are applied. The first of these was the SIF Alpha project *Cross Vector Hub*, which developed a planning and simulation toolset that evaluates a Cross-Vector Energy Hub concept, a degree of coordination the project describes as technically feasible. The second such project was named *Look NortH2*, and explored the potential benefits and associated costs of developing offshore energy hubs, including hydrogen in the UK.

7.5 Modelling Stakeholder Behaviours

The FOGSI network of optimisation tools will initially assume the role of a benign central/social planner, i.e. a hypothetical, benevolent decision-maker that has control over every part of the coupled networks. The central planner uses that control to maximise a social welfare function that includes all users of the networks (consumers, generators, grid service providers etc) subject to the energy system's resource and technology constraints. The solution to the planner's problem is the set of Pareto efficient actions – e.g. the generation, storage and flexibility services dispatch, compressor actions for gas networks etc, where no one can be made better off without making someone else worse off. The solutions reached in this way are identical to those that would be reached by autonomous decision-making entities (market players) interacting through perfectly informed and competitive markets. However, the former is much simpler to compute, since there is no need to calculate market prices and so on.

In reality, the behaviour of the various system stakeholders and market actors will not be so idealised. It is therefore interesting to examine recent innovation projects that explored the behaviours of gas network. The first of these is a live SIF project, recently awarded Alpha funding, named Gas Networks Evolution Simulator. That project has been identified by SIF funding administrators as one that we should communicate with and monitor, due to the thematic similarity. It is concerned with optimising the gas transition using the method of agent-based modelling to simulate interactions between varied network stakeholders.

There are two completed NIA projects on the same theme: *Gas and Electricity Transmission Infrastructure Outlook*, which modelled potential interactions - some competitive - between gas and electricity energy systems; and *Hydrogen Behavioural Change*, that examined behavioural changes that may occur (or in some cases must occur) internally and in relation to external stakeholders, to support a successful transition to a hydrogen dominated gas network.

7.6 System Projections and Scenarios

In the context of this review, the topic of system projections and scenarios refers to the process of transforming a presumed network layout/topology into sequences of network states and forecasts. The representation of the network must include physical parameters, and also representations (ideally probabilistic) of the connected demands, dispatchable generation, weather-driven generation and grid services, along with weather patterns and a representation of human behaviour related variability and uncertainty. These model outputs can then act as inputs to the optimisation problems and solution methods being established in this project.

Looking first at projects that were engaged in building scenarios solely involving the power networks, two completed SIF Discovery projects were found and one completed NIA project. The first Discovery project was named *Scenario Analysis for Nondomestic Network Decarbonisation (SANND)*, which explored the creation of a software tool for displaying forecast scenarios of additional demand on electricity distribution networks. The other was named *FastTrack*, and explored the feasibility of creating an AI simulation tool that calculates the risk-weighted impact of small and large-scale DNO connection requests. The NIA project in this category was named *Understanding Future Energy Loads from Data Centres*, which analysed the dependable-supply requirements of servers, and related this to onsite natural gas or hydrogen generation potential.

Moving on to projections and scenarios purely involving gas networks, there are 3 recently completed NIA projects on this topic. The first was named *Common Planning Pathways*, and was concerned with 'correcting' a perceived underestimation of gas demands in the current FES scenarios. The authors claim that making this 'correction' is essential if the transition is to be managed in a resilient manner, with awareness of societal and commercial risks. The next project was titled *The Economics of Electrolysers Using Curtailed Electricity*, which provided an analysis of the potential hydrogen volumes produced from curtailed electricity out to 2035, plus economic analysis. The 3rd NIA project was named *Hydrogen Navigator*, and used the McKinsey consultancy's optimisation tool to analyse future hydrogen demand, supply, storage and import in SGN's networks.

There are two completed projects that considered projections that span both electrical and gas networks. One was named *Electrolyser Horizons: Unveiling the Techno-economic Landscape for Sustainable Hydrogen Production in GB*, and assessed the challenges, feasibility and potential scale of a robust and sustainable GB hydrogen production industry. The other was the SIF Discovery project, *Probabilistic Pathways for Energy System Planning*, which developed a probabilistic end-to-end network planning methodology for whole energy systems, using advanced computational methods.

The final sub-category here is extreme energy meteorology, i.e. the study of combinations of persistent weather conditions that lead to extreme stress on energy systems. In the case of the FOGSI project, we wish to understand how the network of optimisers would handle such weather extremes in a way that minimises their impact, as measured by either avoiding or minimising any forced reduction in the demand served. The first of two projects in this category is the live NIA project *Extreme Weather and Climate Modelling (Dunkelflaute)*, that is addressing knowledge gaps regarding 'Dunkelflaute' events (i.e. almost no wind or solar generation) and cold low wind spells, including understanding their frequency of occurrence at different levels of severity. The second project, the SIF Alpha project *Scenarios for Extreme Events* took a broader view, modelling black swan events for power networks, including their probabilities and impacts, using a framework known as Model-Based Systems Engineering (MBSE).

7.7 Hydrogen Storage

Hydrogen stores, particularly those large enough to operate on a seasonal timescale, are a very important element of the system models the FOGSI network of solvers works with. It is therefore relevant and interesting to understand the research questions that have been addressed in recent years by innovation projects with hydrogen storage as a theme. It was found that such projects fall into two sub-categories: (i) the planning processes for large scale investment in hydrogen stores and the market stimulus methods that could help achieve those plans; (ii) the investigation of promising/ likely operational methods and principles for the stores in future networks. However, admittedly most of the projects fit into both the planning and operational scale category with one being more central to the theme.

In the former category, there is one currently live Discovery project and 3 completed NIA projects. The live project is named *Intermediate Scale Hydrogen Storage Evaluation (HyWISE)*, and is investigating the potential for decentralised medium-scale hydrogen stores to allow hydrogen hubs in urban and industrial areas – and is therefore of limited applicability for FOGSI. Perhaps the most relevant NIA project was *Energy Storage Strategy*, that produced an UK energy storage strategy that is claimed to be based on "realistic options, not scenarios", and that also explored potential market stimulus methods.

Another NIA project that is relevant to the choice of network topologies adopted for demonstration is *Long Term, Large-Scale Hydrogen Storage Database* – which created a GIS database illustrating optimal sites for geological hydrogen storage – i.e. very large, long-term stores operating on seasonal scales. Looking at much shorter timescales, the NIA project *Linepack Opportunities in the Current and Future Energy System* investigated how the future NTS can develop the required market, policy and regulatory frameworks to support linepack flexibility, given the drastic loss of linepack capability that is inherent to the transition from natural gas to hydrogen.

Regarding the operational sub-category, only one project was found, but it is a live Beta project, named *B-Linepack+*. That project is exploring the feasibility of medium-scale gas storage sites to compensate for the loss of linepack energy capacity for purely hydrogen networks and blends with higher percentages of hydrogen.

7.8 Thermal Storage

The large-scale adoption of thermal storage as part of future energy systems is a real possibility, and one that could bring about a novel form of coupling and flexibility between electrical and gas networks. As such, future versions of the FOGSI tools should be able to incorporate this, and therefore it is relevant to be aware of innovation projects that have investigated them.

Two completed projects were found, the first being the SIF Alpha project *Heat Balance*, which investigated the potential for large-scale inter-seasonal thermal energy storage that bridge misalignment between the wind generation resource and thermal demand. The second, a SIF Discovery project named *Carnot Gas Plant* conducted technical design and commercial modelling for the novel technology of Carnot gas plants that combine large-scale energy storage and high efficiency gas use.

7.9 Gas Network Operational Changes for Hydrogen

This section reports on innovation projects that are investigating/investigated differences in the way gas networks must be operated either when hydrogen is blended into natural gas or for purely hydrogen networks (other than the reduction in linepack stored energy). Understanding the nature of these changes is essential for accurate modelling of future gas networks.

There are two live projects investigating this topic, the largest being *HyNTS FutureGrid Compression*, which is a SIF Beta project that is investigating opportunities to re-purpose existing NTS compression equipment. It is developing technical specifications for hydrogen compressors and using them to assess the suitability of existing infrastructure and evaluating conversion costs. The other live project is the SIF Alpha *Specification of Hydrogen Compressors and Suitability of existing Stock (FastPress)*, which is investigating the use of AI to improve NTS asset configuration planning to ensure sufficient pressure at offtakes in future networks where hydrogen is present.

There are two completed NIA projects for this category, the first being *H21: Wider Impacts of Hydrogen*, which engaged various subject matter experts to gather and synthesise evidence about the characteristic differences between hydrogen versus natural gas and how their affect their transportation. The other project was named *NTS Hydrogen Blending Management Approach*, which investigated how activities carried out by the system operator will likely need updating to accommodate hydrogen blends.

7.10 The Operation of Electrolysers

This section reports on projects that investigated electrolysers: their electrical characteristics, potential demand patters and how to place them within electrical and gas networks to minimise negative effects on the former and maximise benefits for the latter. The insights generated by these projects is certainly informative for FOGSI, but additionally it is likely that the ability of FOGSI's network of optimisers to simulate optimal decision making simultaneously across power and gas networks means that it likely could be used to draw more robust conclusions about the ideal size and placement of electrolysers in future system scenarios.

There is only one currently live project that falls under this category: the NIA project named *Hydrogen Plant Dynamic Models*, which is engaged in the development of a dynamic model for polymer electrolyte membrane (PEM) hydrogen plants – the current technological front runner – within the DIgSILENT PowerFactory software. The only SIF project in this category was the Alpha project *Connectrolyser*, that adopted a whole system approach to identify best ways to connect smaller scale electrolysers to the grid and in a way that supports local energy systems.

Several NIA projects have been completed on this topic, namely:

- *Hydrogen Economy: Reassessing Approaches to Connecting Large Electrolyser Sites (HERACLES)*, which aimed to gain an initial understanding of electrolyser demand patterns and where they should be deployed (within NGED's network).
- *Role and Value of Electrolysers in Low-Carbon GB Energy System*, which developed a whole-system and scenario-based perspective on electrolyser optimum capacity, location, technologies and benefits.
- The *Role for Hydrogen as an Electricity System Asset*, which explored how hydrogen markets might interact with the electricity system, and how targeted investment can support power networks.
- *Hydrogen Production for Thermal Electricity Constraints Management*, which investigated the potential for electrolysers to provide constraint management services if well placed and operated, as well as an providing an analysis of appropriate market signals to encourage strong investment.
- *Hy-Voltage*, that explored the potential benefits of flexible vector conversion links between gas and electricity distribution networks, from the perspective of the latter.

There are a further two completed SIF projects about electrolysers that are of less direct relevance to this project, but are worth including due to the potentially very significant contribution to sustainability – in a broader sense than simply decarbonising energy systems – of the ideas they explore. Ideas that ideally could be incorporated into system models tackled by a future version of the FOGSI optimisers.

The first is the SIF Alpha project *HyNTS Waste Heat Recovery for Electrolysis*, that was concerned with demonstrating efficiency improvements in hydrogen production through the use of waste heat produced by the transportation of gases through the networks. The other is the SIF Discovery project *NextGen Electrolysis: Wastewater to Green Hydrogen*, which explored the possibility of mitigating the extremely large water demand of conventional electrolysis through alternative technologies that can use waste water, thus allowing the introduction of electrolysis to smaller isolated communities.

7.11 Modelling Resilience

One of the main objectives of solving optimal operational plans simultaneously across the energy vectors is to increase resilience, both to infrequent but high impact events such as random coincident unplanned and planned outages, and to weather extremes such as exceptionally long cold and calm periods. Research on how best to model and capture resilience is therefore highly relevant, and proposed metrics might be used as a means of quantifying the benefits of our approach.

Two completed projects were found, both SIF Alpha, that modelled the resilience of possible future systems at the national level. The first was named *Whole Energy System Resilience Vulnerability Assessment (WELLNESS)*, which proposed new whole system resilience standards that account for multi-vector energy flexibility. The other was *Hydrogen Cost Reduction (HyCoRe)*, which identified regions of GB with strong potential for hydrogen produced from offshore-wind, and then ran system simulations for the resulting scenarios that measured their resilience.

Two others, both completed SIF Discovery projects, also investigated the quantification of resilience, but at a local level. The project *Smart Hydrogen and Resilient Energy Decarbonisation (SHARED)* explored the potential of low-cost hydrogen production and storage to improve the resilience of rural communities. The project *Decentralised System Resilience* investigated opportunities for gas network infrastructure to support storage and balancing in a decentralised UK energy system out to 2050.

7.12 Nuclear Co-Generation

Several projects over the last few years have investigated the potential future role of advanced nuclear generators that are specifically designed to generate both hydrogen and electrical power simultaneously, including mitigation of any negative impacts on the electrical networks and the contribution they could potentially make to meeting hydrogen demand. This topic is relevant to our project since it introduces an entirely new type of coupling between gas and electricity networks. On the one hand, it is good for the project to be aware of the circumstances in which this new type of coupling may need to be included in models. On the other hand, we argue that the fully integrated optimisation introduced by this project is the only way to model the whole system impacts and benefits of such generation on the networks that is sufficiently rigorous and robust.

Under the topic of the electricity network impacts of advanced nuclear co-generation there is the recently completed NIA project *Understanding the Whole System Impacts of Nuclear Co-Generation on Electricity Transmission Infrastructure*, that modelled the impacts of nuclear cogeneration on the transmission network using a Energy System Modelling Environment tool. There is also the completed SIF Discovery project *Nuclear Net Zero Opportunities (N-NZO)*, which explored strategies for integrating advanced nuclear technologies.

On the topic of the positive contribution of nuclear co-generation to meeting future hydrogen demand, there is the currently live NIA project *Unlocking the Role of Nuclear in Low Carbon Hydrogen and Heat*, that describes itself as exploring how nuclear energy can support a whole system transition through hydrogen generation and heat networks. There was also the NIA project *Scaling Hydrogen with Nuclear Energy (SHyNE)*, that investigated the possible use of nuclear power connected to GDNs to deliver the future demand for hydrogen production.

7.13 Decarbonising Transport

The topic of the decarbonisation of transport in GB is relevant to this project since energy system scenarios with very different extents of transport decarbonisation and very different ways of achieving it (e.g. electrification vs. replacement of fossil fuels with green hydrogen) have highly divergent demand patterns and system coupling. Indeed, different transport decarbonisation scenarios can lead to network coupling mechanisms that differ both quantitatively and qualitatively. The optimisation methods developed by the FOGSI project must be robust and flexible enough to accommodate all plausible variants of the transport decarbonisation pathway.

Looking first at projects related to the railways, there is one live NIA project, *H2 Rail*, that explores the feasibility of integrating hydrogen train refuelling infrastructure for planning strategic hydrogen pipeline routes. Another SIF Alpha project named *A Holistic Hydrogen Approach to Heavy Duty Transport (H2H)* demonstrated how the decarbonisation of rail using flexible green hydrogen can save costs, carbon and time. Finally, the SIF Discovery project *Rail Decarbonisation Planning* was concerned with discovering and implementing deployment of the most effective, efficient, and appropriate solutions to decarbonise rail.

Moving on to aviation, the NIA project *Hydrogen for Aviation* examined the potential scale and timing requirements for installing hydrogen infrastructure for decarbonising aviation, and potential barriers to meeting those requirements. The SIF Discovery project *Carbon and Hydrogen Transportation to SAF Production Facilities* explored how hydrogen and carbon networks could support sustainable aviation fuel production in the UK becoming large-scale.

A single project – *HyNTS Maritime*, investigated the shipping sector from the point of view of hydrogen networks. However, rather than considering the fuelling of ships with green hydrogen, this project was concerned with determining how the NTS could support UK maritime ports as links to large scale UK-wide hydrogen infrastructure.

Considering innovation projects that are not specific to a single mode of transport, the most significant current activity is associated with the live SIF Beta project *HyNTS FutureGrid Deblending*. That project seeks to demonstrate a national NTS-level deblending technology, to enable large-scale hydrogen distribution for hydrogen refuelling stations. Working in a framework of hydrogen and methane sharing a network, but with different interfaces, makes the project less relevant to FOGSI, which has made the decision to assume separate networks for the purposes of tractability. However, the fact that such a large project – with a budget of £12.4 million – is working with a blending and deblending framework, highlights that our project's scope of applicability isn't universal.

Two other projects were recently completed with non-specific modes of transport in mind. The first is the NIA project *Deblending Rollout Strategy: Phase 2*, that was concerned with developing a UK-wide rollout strategy for deblending gas for transportation, considering NTS locations and clustering. The SIF Discovery project *Multimodal Hydrogen Transport Refuelling Study* evaluated the potential for hydrogen in transport across the North of England, achieved through a joined-up regional strategy.

7.14 Transporting CO2

One extension of this project's scope and methodology which would need to be delivered at some future time to ensure the methodology is fully realistic is the inclusion into the model of CO2 networks that transport captured CO2 to locations where it can be stored for the long term. This captured CO2 would be generated from the burning of natural gas and biogas, and also hydrogen production through steam methane reforming – activities that are present in 2050 even in the most radical scenarios. Such networks would have their own complex sets of constraints and would be coupled with all three of electrical, natural gas and hydrogen networks. It is therefore relevant and interesting to examine the current state of affairs and extent of research activities in this field.

The most significant activity on this topic is the live Beta project *FutureGrid CO2*, which is examining how National Gas can repurpose parts of its gas transmission network to transport gaseous-phase carbon dioxide safely. There are also two completed NIA projects: *Carbon Transportation Technical Demonstration: Phase 1*, which evaluated opportunities to transport carbon in the NTS and determined the key areas of work required for deployment; *Carbon Networks* provided SGN with a pragmatic assessment of the role of utilising the existing gas network in the growing UK CCUS market. Overall, it can be said that there is a modest level of research activity linked to this topic, and any future work that used the methods developed by FOGSI would very much be breaking new ground.

7.15 Inclusion of Water Network Constraints

Another constrained and multiply coupled network that would ultimately need to be included in a complete view of interconnected constrained networks is water, due e.g. to the water needs of electrolysis, methane steam reformation and potentially the creation of water from hydrogen powered generators.

There are two completed NIA projects on this topic: *Energy Water Nexus*, that investigated a least cost energy system design that included costs associated with water system constraints; *Green Hydrogen Production Impacts on Water Usage* developed a local energy model to include water as a dependent system vector. There was also a SIF Discovery project, *Shifting Currents*, that investigated novel grid/system support from the operations of the drinking and wastewater networks of water utilities.

7.16 Geographical Aspects of Hydrogen Networks

The last few sections of this review have covered innovation projects that provide insight about the likely locations and scale of new hydrogen networks that might be built. This final section presents other relevant projects that are also concerned with generating such insight, without being also being primarily driven by a specific theme such as nuclear cogeneration. Such insights are useful since they facilitate reflection on how general or representative the energy system configuration/scenario adopted to demonstrate this project's approach might be, and whether other geographical scenarios for the future system might pose different technical challenges for the methodology.

Turning initially to projects concerned with national scale insights, 4 NIA projects were found – two of them live and two completed. The first live project is named *Indus 2.0*, and is engaged with identifying the location of industrial customers that might be most suitable for being served by a hydrogen network, characterising their energy consumption, and drafting data-sharing agreements with them. The project *Hydrogen Backbone Social Economic Assessment* is developing what it describes as 'credible and independently modelled pathways' to test the economic case of developing a hydrogen backbone. The completed project *Spatial GB Clean Heat Pathway Model* impressively developed an integrated, cross-vector model of the whole heating system within GB for heat decarbonisation. Meanwhile, the other completed project *Achieving Future Hydrogen Demand* is a research study assessing the future demand for hydrogen across SGN's regional networks and the potential role these networks' infrastructure could play in facilitating access to hydrogen.

Two further completed projects were concerned with the spatial aspects of hydrogen networks, but on local scales. The SIF Alpha project *East Midlands Hydrogen Storage (EMStor)* researched the viability of a hydrogen pipeline project aiming to connect hydrogen production at a specific site (Ratcliffe on Soar) to major industrial and power off-takers in the region. Finally, the completed NIA project *Cumbrian Hydrogen Vision and Pathway: Phase 1 Feasibility* developed a detailed concept for a hydrogen system in Cumbria and proposed a pathway for its creation.

7.17 Most Relevant Projects

In summary, the most relevant of the reviewed projects are deemed to be the following:

***Live* SIF Beta Projects:**

- Intelligent Gas Grid (SNG)
- Climate Resilience Decision Optimiser (CREDO+) (UKPN)

***Live* SIF Alpha Projects:**

- Gas Networks Evolution Simulator (NGN)
- B-Linepack+ (NGT)

***Live* NIA Projects:**

- GPU Accelerated Grid Optimisation (NESO)
- Volta: Grand Optimiser Design Philosophy (NESO)
- Extreme Weather and Climate Modelling (Dunkelflaute) (NESO)
- Hydrogen Backbone Social Economic Assessment (NGT)

Completed SIF Alpha Projects:

- Whole Energy System Resilience Vulnerability Assessment (WELLNESS) (NGET)
- Heat Balance (SPEN)

Completed SIF Discovery:

- Carbon and Hydrogen Transportation to SAF Production Facilities (NGT)

Completed NIA Projects:

- Data Sharing Protocols (SGN)
- Hydrogen Production for Thermal Electricity Constraints Management (NESO)
- Energy Water Nexus (NGET)

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1 General gas models

Baumrucker et al.: MPEC strategies for cost optimization of pipeline operations

B. T. Baumrucker and L. T. Biegler. "MPEC strategies for cost optimization of pipeline operations". In: *Computers & Chemical Engineering* 34.6 (June 10, 2010). Publisher: Pergamon, pp. 900–913. ISSN: 0098-1354. DOI: 10.1016/J.COMPCHEMENG.2009.07.012.

Abstract: This study develops a mathematical program with equilibrium constraints (MPECs) approach for efficient operation of gas pipelines. The resulting model handles time dependent operations in order to determine minimum energy consumption and operating cost over a given time horizon. The MPEC structure also allows flow reversals, flow transitions and other nonsmooth elements to be incorporated within the approach. Applied to industrial gas pipelines, this approach can also deal with customer demand satisfaction in the presence of compressor outages and minimize recovery time for systems that are unable to meet customer demands at all times. A large-scale oxygen pipeline case study is considered to demonstrate this approach and complex energy pricing schemes are also applied to this problem. These schemes include time of day electricity pricing, along with extensions to Real Time Pricing and Day Ahead Pricing. Compared to flat rate and minimum energy optimizations, respectively, we observe operating cost savings up to 5.13% for time of day electricity pricing and up to 12.85% for Real Time Pricing. © 2009 Elsevier Ltd. All rights reserved.

Bayani et al.: Natural Gas Short-Term Operation Problem With Dynamics

Reza Bayani and Saeed Manshadi. "Natural Gas Short-Term Operation Problem With Dynamics: A Rank Minimization Approach". In: *2023 IEEE Power & Energy Society General Meeting (PESGM)*. 2023 IEEE Power & Energy Society General Meeting (PESGM). ISSN: 1944-9933. July 2023, pp. 1–1. DOI: 10.1109/PESGM52003.2023.10253264.

Abstract: Natural gas-fired generation units can hedge against the volatility in the uncertain renewable generation, which may occur during very short periods. It is crucial to utilize models capable of correctly capturing the natural gas network dynamics induced by the volatile demand of gas-fired units. The Weymouth equation is commonly implemented in literature to avoid dealing with the mathematical complications of solving the original governing differential equations of the natural gas dynamics. However, it is shown in this paper that this approach is not reliable in the short-term operation problem. Here, the merit of the non-convex transient model is compared with the simplified Weymouth equation, and the drawbacks of employing the Weymouth equation are illustrated. The results demonstrate how changes in the natural gas demand are met by adjustment in the pressure within pipelines rather than the output of natural gas suppliers. This work presents a convex relaxation scheme for the original non-linear and non-convex natural gas flow equations with dynamics, utilizing a rank minimization approach to ensure the tightness. The proposed method renders a computationally efficient framework that can accurately solve the non-convex non-linear gas operation problem and accurately capture its dynamics. Also, the results suggest that the proposed model improves the solution optimality and solution time compared to the original non-linear non-convex model. Finally, the scalability of the proposed approach is verified in the case study.

Brouwer et al.: Gas Pipeline Models Revisited: Model Hierarchies, Nonisothermal Models, and Simulations of Networks

Jens Brouwer, Ingenuin Gasser, and Michael Herty. “Gas Pipeline Models Revisited: Model Hierarchies, Nonisothermal Models, and Simulations of Networks”. In: *Multiscale Modeling & Simulation* 9.2 (Apr. 2011), pp. 601–623. ISSN: 1540-3459. DOI: 10.1137/100813580.

Abstract: By using asymptotic analysis we derive most of the known and also new nonisothermal pipeline models starting from transient gas equations. We introduce proper scalings to identify valid regimes for the derived models and extend them to networks. Finally, we perform numerical simulations on a single pipe as well-posed as on a small network. We compare both isothermal and nonisothermal flow and pressure predictions with results obtained from the literature. © 2011 Society for Industrial and Applied Mathematics.

Burlacu et al.: Maximizing the storage capacity of gas networks: a global MINLP approach

Robert Burlacu, Herbert Egger, Martin Groß, Alexander Martin, Marc E. Pfetsch, Lars Schewe, Mathias Sirvent, and Martin Skutella. “Maximizing the storage capacity of gas networks: a global MINLP approach”. In: *Optimization and Engineering* 20.2 (June 1, 2019). Publisher: Springer New York LLC, pp. 543–573. ISSN: 15732924. DOI: 10.1007/s11081-018-9414-5.

Abstract: In this paper, we study the transient optimization of gas networks, focusing in particular on maximizing the storage capacity of the network. We include nonlinear gas physics and active elements such as valves and compressors, which due to their switching lead to discrete decisions. The former is described by a model derived from the Euler equations that is given by a coupled system of nonlinear parabolic partial differential equations (PDEs). We tackle the resulting mathematical optimization problem by a first-discretize-then-optimize approach. To this end, we introduce a new discretization of the underlying system of parabolic PDEs and prove well-posedness for the resulting nonlinear discretized system. Endowed with this discretization, we model the problem of maximizing the storage capacity as a non-convex mixed-integer nonlinear problem (MINLP). For the numerical solution of the MINLP , we algorithmically extend a well-known relaxation approach that has already been used very successfully in the field of stationary gas network optimization. This method allows us to solve the problem to global optimality by iteratively solving a series of mixed-integer problems. Finally, we present two case studies that illustrate the applicability of our approach. © 2018, Springer Science+Business Media, LLC, part of Springer Nature.

Conejo et al.: Operations and Long-Term Expansion Planning of Natural-Gas and Power Systems: A Market Perspective

By Antonio J. Conejo, Sheng Chen, and Gonzalo E. Constante. “Operations and Long-Term Expansion Planning of Natural-Gas and Power Systems: A Market Perspective”. In: *Proceedings of the IEEE* 108.9 (Sept. 1, 2020). Publisher: Institute of Electrical and Electronics Engineers Inc., pp. 1541–1557. ISSN: 15582256. DOI: 10.1109/JPROC.2020.3005284.

Abstract: Natural-gas and power systems are increasingly interdependent due to the integration of an increasing number of combined cycle gas turbines in the power generation mix. However, natural gas and power systems are generally independently operated. This is the result of history and the fact that natural gas has not been important for electricity production until recently. Adopting a power system perspective, this article reviews in a tutorial manner models for the operations and long-term expansion planning of interdependent but independently operated natural-gas and power systems.

Fügenschuh et al.: Physical and technical fundamentals of gas networks

Armin Fügenschuh, Björn Geißler, Ralf Gollmer, Antonio Morsi, Jessica Rövekamp, Martin Schmidt, Klaus Spreckelsen, and Marc C. Steinbach. “Physical and technical fundamentals of gas networks”. In: *Evaluating Gas Network Capacities.* Ed. by Thorsten Koch, Benjamin Hiller, Marc E. Pfetsch, and Lars Schewe. Society for Industrial and Applied Mathematics, Mar. 2015, pp. 17–43. DOI: 10.1137/1.9781611973693.CH2.

Abstract: This chapter describes the fundamentals of gas transport. This includes an introduction to the basic terminology and basic physical laws with respect to natural gas. Then the basic elements needed to represent gas networks are discussed: pipes, resistors, valves, control valves, and compressor machines and drives. These elements can be grouped into larger entities like compressor groups and subnetwork operation modes.

Ghilardi et al.: Optimal operation of large gas networks: MILP model and decomposition algorithm

Lavinia Marina Paola Ghilardi, Francesco Casella, Daniele Barbati, Roberto Palazzo, and Emanuele Martelli. “Optimal operation of large gas networks: MILP model and decomposition algorithm”. In: *Computer Aided Chemical Engineering* 52 (Jan. 1, 2023). Publisher: Elsevier, pp. 915–920. ISSN: 1570-7946. DOI: 10.1016/B978-0-443-15274-0.50146-3.

Abstract: As of today, natural gas is one of the most widely deployed energy sources and its transport relies on large-scale infrastructures managed by the expertise of transmission system operators. In this framework, this paper proposes a Mixed-Integer-Linear-Programming model and a decomposition algorithm to optimize the operation of gas networks. The model aims to minimize the CO2 emissions from compressor stations by optimizing the unit commitment of the gas-turbine-driven compressors, their loads and the dynamic operation of the network. The formulation includes the detailed linearization of the performance

maps of the machines, their technical limitations, the dynamic conservation equations of the pipes, and the operating constraints of control valves. On top of this, the algorithm is capable of handling flow reversals in pipes, being suitable also for networks with cyclic topology. The resulting large scale MILP is extremely challenging to solve, and therefore we developed a decomposition algorithm to speed up the computational time. The decomposition algorithm is composed by two MILP levels, where the master level contains a simplified model of the compression stations and of pipe friction, while the lower level is the actual detailed model. The aim of the master level is to remove unused compression stations and to fix the flow direction in pipes in the lower level, thus reducing the size of this second problem. At the end of each bilevel iteration, an integer cut is added to the master problem to explore different combinations of committed stations. The algorithm is effectively tested on the Italian gas network case study, featuring 112 pipes and 9 compressor stations, each composed by 3-5 units.

Gugat et al.: Modeling, control, and numerics of gas networks

Martin Gugat and Michael Herty. "Modeling, control, and numerics of gas networks". In: *Handbook of Numerical Analysis*. ISSN: 1570-8659. Elsevier, 2022, pp. 59–86. ISBN: 978-0-323-85059-9. DOI: 10.1016/bs.hna.2021.12.002.

Abstract: In this chapter we survey recent progress on mathematical results on gas flow in pipe networks with a special focus on questions of control and stabilization. We briefly present the modeling of gas flow and coupling conditions for flow through vertices of a network. Our main focus is on gas models for spatially one-dimensional flow governed by hyperbolic balance laws. We survey results on classical solutions as well as weak solutions. We present results on well-posedness, controllability, feedback stabilization, the inclusion of uncertainty in the models and numerical methods.

Gugat et al.: MIP-based instantaneous control of mixed-integer PDE-constrained gas transport problems

Martin Gugat, Günter Leugering, Alexander Martin, Martin Schmidt, Mathias Sirvent, and David Wintergerst. "MIP-based instantaneous control of mixed-integer PDE-constrained gas transport problems". In: *Computational Optimization and Applications* 70.1 (May 1, 2018), pp. 267–294. ISSN: 1573-2894. DOI: 10.1007/s10589-017-9970-1.

Abstract: We study the transient optimization of gas transport networks including both discrete controls due to switching of controllable elements and nonlinear fluid dynamics described by the system of isothermal Euler equations, which are partial differential equations in time and 1-dimensional space. This combination leads to mixed-integer optimization problems subject to nonlinear hyperbolic partial differential equations on a graph. We propose an instantaneous control approach in which suitable Euler discretizations yield systems of ordinary differential equations on a graph. This networked system of ordinary differential equations is shown to be well-posed and affine-linear solutions of these systems are derived analytically. As a consequence, finite-dimensional mixed-integer linear optimization problems are obtained for every time step that can be solved to global optimality using general-purpose solvers. We illustrate our approach in practice by presenting numerical results on a realistic gas transport network.

Hante et al.: Gas Transport Network Optimization

Falk M. Hante and Martin Schmidt. “Gas Transport Network Optimization: Mixed-Integer Nonlinear Models”. In: *Encyclopedia of Optimization*. Springer, Cham, 2023, pp. 1–8. ISBN: 978-3-030-54621-2. DOI: 10.1007/978-3-030-54621-2_873-1.

Abstract: Although modern societies strive towards energy systems that are entirely based on renewable energy carriers, natural gas is still one of the most important energy sources. This became even more obvious in Europe with Russia’s 2022 war against the Ukraine and...

Hari et al.: Operation of Natural Gas Pipeline Networks With Storage Under Transient Flow Conditions

Sai Krishna Kanth Hari, Kaarthik Sundar, Shriram Srinivasan, Anatoly Zlotnik, and Russell Bent. “Operation of Natural Gas Pipeline Networks With Storage Under Transient Flow Conditions”. In: *IEEE Transactions on Control Systems Technology* 30.2 (Mar. 2022), pp. 667–679. ISSN: 1558-0865. DOI: 10.1109/TCST.2021.3071316.

Abstract: We formulate a nonlinear optimal control problem for intraday operation of a natural gas pipeline network that includes storage reservoirs. The dynamics of compressible gas flow through pipes, compressors, reservoirs, and wells are considered. In particular, a reservoir is modeled as a rigid, hollow container that stores gas under isothermal conditions and uniform density, and a well is modeled as a vertical pipe. For each pipe, flow dynamics are described by a coupled partial differential equation (PDE) system in density and mass flux variables, with momentum dissipation modeled using the Darcy–Wiesbach friction approximation. Compressors are modeled as scaling up the pressure of gas between the inlet and outlet. The governing equations for all network components are spatially discretized and assembled into a nonlinear differential-algebraic equation (DAE) system, which synthesizes above-ground pipeline and subsurface reservoir dynamics into a single reduced-order model. We seek to maximize an objective function that quantifies economic profit and network efficiency subject to the flow equations and inequalities that represent operating limitations. The problem is solved using a primal–dual interior point solver, and the solutions are validated in computational experiments and simulations on several pipeline test networks to demonstrate the effectiveness of the proposed methodology.

Hennings et al.: Optimizing transient gas network control for challenging real-world instances using MIP-based heuristics

Felix Hennings, Kai Hoppmann-Baum, and Janina Zittel. “Optimizing transient gas network control for challenging real-world instances using MIP-based heuristics”. In: *Open Journal of Mathematical Optimization* 5 (2024), pp. 1–34. ISSN: 2777-5860. DOI: 10.5802/ojmo.29.

Abstract: Optimizing the transient control of gas networks is a highly challenging task. The corresponding model incorporates the combinatorial complexity of determining the settings for the many active elements as well as the non-linear and non-convex nature of the physical and technical principles of gas transport. In this paper, we present the latest improvements of our ongoing work to tackle this problem for real-world, large-scale problem instances: By adjusting our mixed-integer non-linear programming model regarding the gas compression capabilities in the network, we reflect the technical limits of the underlying units more accurately while maintaining a similar overall model size. In addition, we introduce a new algorithmic approach that is based on splitting the complexity of the problem by first finding assignments for discrete variables and then determining the continuous variables as locally optimal solution of the corresponding non-linear program. For the first task, we design multiple different heuristics based on concepts for general time-expanded optimization problems that find solutions by solving a sequence of sub-problems defined on reduced time horizons. To demonstrate the competitiveness of our approach, we test our algorithm on particularly challenging historical demand scenarios. The results show that high-quality solutions are obtained reliably within short run times, making the algorithm well-suited to be applied at the core of time-critical industrial applications.

Hoppmann-Baum et al.: Optimal Operation of Transient Gas Transport Networks

Kai Hoppmann-Baum, Felix Hennings, Ralf Lenz, Uwe Gotzes, Nina Heinecke, Klaus Spreckelsen, and Thorsten Koch. “Optimal Operation of Transient Gas Transport Networks”. In: *Optimization and Engineering* 22.2 (June 1, 2021). Publisher: Springer, pp. 735–781. ISSN: 15732924. DOI: 10.1007/s11081-020-09584-x.

Abstract: In this paper, we describe an algorithmic framework for the optimal operation of transient gas transport networks consisting of a hierarchical MILP formulation together with a sequential linear programming inspired post-processing routine. Its implementation is part of the KOMPASS decision support system, which is currently used in an industrial setting. Real-world gas transport networks are controlled by operating complex pipeline intersection areas, which comprise multiple compressor units, regulators, and valves. In the following, we introduce the concept of network stations to model them. Thereby, we represent the technical capabilities of a station by hand-tailored artificial arcs and add them to network. Furthermore, we choose from a predefined set of flow directions for each network station and time step, which determines where the gas enters and leaves the station. Additionally, we have to select a supported simple state, which consists of two subsets of artificial arcs: Arcs that must and arcs that cannot be used. The goal is to determine a stable control of the network satisfying all supplies and demands. The pipeline intersections, that are represented by the network stations, were initially built centuries ago. Subsequently, due to updates, changes, and extensions, they evolved into highly complex and involved topologies. To extract their basic properties and to model them using computer-readable and optimizable descriptions took several years of effort. To support the dispatchers in controlling the network, we need to compute a con-

tinuously updated list of recommended measures. Our motivation for the model presented here is to make fast decisions on important transient global control parameters, i.e., how to route the flow and where to compress the gas. Detailed continuous and discrete technical control measures realizing them, which take all hardware details into account, are determined in a subsequent step. In this paper, we present computational results from the KOMPASS project using detailed real-world data. © 2021, The Author(s).

Huck et al.: Transient Modeling and Simulation of Gas Pipe Networks with Characteristic Diagram Models for Compressors

Christoph Huck and Caren Tischendorf. "Transient Modeling and Simulation of Gas Pipe Networks with Characteristic Diagram Models for Compressors". In: *PAMM* 17.1 (Dec. 2017). Publisher: Wiley, pp. 707–708. ISSN: 1617-7061. DOI: 10.1002/PAMM.201710322.

Abstract: One challenge for the simulation and optimization of real gas pipe networks is the treatment of compressors. Their behavior is usually described by characteristic diagrams reflecting the connection of the volumetric flow and the enthalpy change or shaft torque. Such models are commonly used for an optimal control of compressors and compressor stations [4,7] using stationary models for the gas flow through the pipes. For transient simulations of gas networks, simplified compressor models have been studied in [1–3]. Here, we present a transient simulation of gas pipe networks with characteristic diagram models of compressors using a stable network formulation as (partial) differential-algebraic system. (© 2017 Wiley-VCH Verlag GmbH & Co. KGaA, Weinheim).

Koch et al.: Evaluating Gas Network Capacities

Thorsten Koch, Benjamin Hiller, Marc E. Pfetsch, and Lars Schewe, eds. *Evaluating Gas Network Capacities.* Publication Title: Evaluating Gas Network Capacities. Society for Industrial and Applied Mathematics, Mar. 2015. DOI: 10.1137/1.9781611973693.

Abstract: This book addresses a seemingly simple question: Can a certain amount of gas be transported within a pipeline network? The question is difficult, however, when asked in relation to a meshed nationwide gas transportation network and when taking into account technical details and discrete decisions, as well as regulations, contracts, and varying demands involved. This book provides an introduction to the field of gas transportation planning and discusses in detail the advantages and disadvantages of several mathematical models that address gas transport within the context of the technical and regulatory framework. It shows how to solve the models using sophisticated mathematical optimization algorithms and includes examples of large-scale applications of mathematical optimization to this real-world industrial problem. Readers will also find a glossary of gas transport terms, tables listing the physical and technical quantities and constants used throughout the book, and a reference list of regulation and gas business literature.

Krishna et al.: Relaxations of the Steady Optimal Gas Flow Problem for a Non-Ideal Gas

Sai Krishna, Kanth Hari, Kaarthik Sundar, Shriram Srinivasan, and Russell Bent. "Relaxations of the Steady Optimal Gas Flow Problem for a Non-Ideal Gas". In: (). ISBN: 2308.13009v1. arXiv: 2308.13009v1.

Abstract: Natural gas ranks second in consumption among primary energy sources in the United States. The majority of production sites are in remote locations, hence natural gas needs to be transported through a pipeline network equipped with a variety of physical components such as compressors, valves, control valves, etc. Thus, from the point of view of both economics and reliability, it is desirable to achieve optimal transportation of natural gas using these pipeline networks. The physics that governs the flow of natural gas through various components in a pipeline network is governed by nonlinear and non-convex equality and inequality constraints and the most general steady-flow operations problem takes the form of a Mixed Integer Nonlinear Program (MINLP). In this paper, we consider one example of steady-flow operations-the Optimal Gas Flow (OGF) problem for a natural gas pipeline network that minimizes the production cost subject to the physics of steady-flow of natural gas. The ability to quickly determine global optimal solution and a lower bound to the objective value of the OGF for different demand profiles plays a key role in efficient daytoday operations. One strategy to accomplish this relies on tight relaxations to the nonlinear constraints of the OGF. Currently, many nonlinear constraints that arise due to modeling the non-ideal equation of state either do not have relaxations or have relaxations that scale poorly for realistic network sizes. In this work, we combine recent advancements in the development of polyhedral relaxations for univariate functions to obtain tight relaxations that can be solved within a few seconds on a standard laptop. We demonstrate the quality of these relaxations through extensive numerical experiments on very large scale test networks available in the literature and we find that the proposed relaxation is able to prove optimality in 92% instances that were used for the experiments.

Mak et al.: Dynamic Compressor Optimization in Natural Gas Pipeline Systems

Terrence W. K. Mak, Pascal Van Hentenryck, Anatoly Zlotnik, and Russell Bent. "Dynamic Compressor Optimization in Natural Gas Pipeline Systems". In: *INFORMS Journal on Computing* 31.1 (Feb. 2019). Publisher: Institute for Operations Research and the Management Sciences (INFORMS), pp. 40–65. ISSN: 1091-9856, 1526-5528. DOI: 10.1287/ijoc.2018.0821.

Abstract: The growing dependence of electric power systems on gas-fired generators to balance fluctuating and intermittent production by renewable energy sources has increased the variation and volume of flows withdrawn from natural gas transmission pipelines. Adapting pipeline operations to maintain efficiency and security under these dynamic conditions requires optimization methods that account for substantial intraday transients and can rapidly compute solutions in reaction to generator re-dispatch. Here, we present a computationally efficient method for minimizing gas compression costs under dynamic conditions where deliveries to customers are described by time-dependent mass flows.

The optimization method uses a simplified representation of gas flow physics, provides a choice of discretization schemes in time and space, and exploits a two-stage approach to minimize energy costs and ensure smooth and physically meaningful solutions. The resulting large-scale NLPs are solved using an interior point method. The optimization scheme is validated by comparing the solutions with an integration of the dynamic equations using an adaptive timestepping differential equation solver, as well as a different, recently proposed optimal control scheme. The comparison shows that solutions to the discretized problem are feasible for the continuous problem and also practical from an operational standpoint. The results also indicate that our scheme produces at least an order of magnitude reduction in computation time relative to the state of the art and scales to large gas transmission networks with more than 6,000 kilometers of total pipeline. The online supplement is available at https://doi.org/10.1287/ijoc.2018.0821 .

Marina et al.: A MILP approach for the operational optimization of gas networks

Lavinia Marina, Paola Ghilardi, Matteo Luigi De Pascali, Francesco Casella, Daniele Barbati, Roberto Palazzo, and Emanuele Martelli. "A MILP approach for the operational optimization of gas networks". In: *IFAC PapersOnLine* 55.9 (2022), pp. 321–326. DOI: 10.1016/j.ifacol.2022.07.056.

Abstract: Nowadays, natural gas is one of the primary energy resources employed in many sectors, and it can be regarded as a bridge fuel in the decarbonization process. The transport of natural gas relies on a complex infrastructure, which needs to be properly managed to minimize energy consumption and CO2 emissions. This study proposes a Mixed Integer Linear Programming formulation capable of optimizing the unit commitment (on/off) of the gas-turbine-driven compressors, their loads and the dynamic operation of the network. The gas network dynamic model has been discretized in space and time, and the friction term has been linearized. The performance maps of the gas-turbine-driven compressors have been linearized using the convex-hull approach. The model includes all the technical limitations of the gas-turbine-driven compressors and it can handle flow reversals on all pipes. Moreover it is suitable for cyclic networks. The MILP model is applied to a case study with 4 compressor stations, each containing multiple gas turbine driven compressors, and a cyclic network consisting of 29 pipes.

Schmidt et al.: Gas Transport Network Optimization

Martin Schmidt and Falk M. Hante. "Gas Transport Network Optimization: PDE-Constrained Models". In: *Encyclopedia of Optimization*. Springer, Cham, 2023, pp. 1–7. ISBN: 978-3-030-54621-2. DOI: 10.1007/978-3-030-54621-2_872-1.

Abstract: The optimal control of gas transport networks was and still is a very important topic for modern economies and societies. Accordingly, a lot of research has been carried out on this topic during the last years and decades. Besides mixed-integer aspects in gas...

Tomasgard et al.: Optimization Models for the Natural Gas Value Chain

Asgeir Tomasgard, Frode Rømo, Marte Fodstad, and Kjetil Midthun. “Optimization Models for the Natural Gas Value Chain”. In: *Geometric Modelling, Numerical Simulation, and Optimization*. Berlin, Heidelberg: Springer Berlin Heidelberg, 2007, pp. 521–558. ISBN: 978-3-540-68782-5. DOI: 10.1007/978-3-540-68783-2_16.

Abstract: In this paper we give an introduction to modelling the natural gas value chain including production, transportation, processing, contracts, and markets. The presentation gives insight in the complexity of planning in the natural gas supply chain and how optimization can help decision makers in a natural gas company coordinate the different activities. We present an integrated view from the perspective of an upstream company. The paper starts with decribing how to model natural gas transportation and storage, and at the end we present a stochastic portfolio optimization model for the natural gas value chain in a liberalized market.

Zavala: Stochastic optimal control model for natural gas networks

Victor M. Zavala. “Stochastic optimal control model for natural gas networks”. In: *Computers and Chemical Engineering* 64 (May 7, 2014), pp. 103–113. ISSN: 00981354. DOI: 10.1016/J.COMPCHEMENG.2014.02.002.

Abstract: We present a stochastic optimal control model to optimize gas network inventories in the face of system uncertainties. The model captures detailed network dynamics and operational constraints and uses a weighted risk-mean objective. We perform a degrees-of-freedom analysis to assess operational flexibility and to determine conditions for model consistency. We compare the control policies obtained with the stochastic model against those of deterministic and robust counterparts. We demonstrate that the use of risk metrics can help operators to systematically mitigate system volatility. Moreover, we discuss computational scalability issues and effects of discretization resolution on economic performance. © 2014 Elsevier Ltd.

2 Gas component models

Arsad et al.: Hydrogen electrolyser technologies and their modelling for sustainable energy production: A comprehensive review and suggestions

A. Z. Arsad, M. A. Hannan, Ali Q. Al-Shetwi, R. A. Begum, M. J. Hossain, Pin Jern Ker, and TM Indra Mahlia. “Hydrogen electrolyser technologies and their modelling for sustainable energy production: A comprehensive review and suggestions”. In: *International Journal of Hydrogen Energy* 48.72 (Aug. 22, 2023). Publisher: Pergamon, pp. 27841–27871. ISSN: 0360-3199. DOI: 10.1016/J.IJHYDENE.2023.04.014.

Abstract: The advancement of hydrogen technology is driven by factors such as climate change, population growth, and the depletion of fossil fuels. Rather than focusing on the controversy surrounding the environmental friendliness of hydrogen production, the primary goal of the hydrogen economy is to introduce hydrogen as an energy carrier alongside electricity. Water electrolysis is currently gaining popularity because of the rising demand for environmentally friendly hydrogen production. Water electrolysis provides a sustainable, eco-friendly, and high-purity technique to produce hydrogen. Hydrogen and oxygen produced by water electrolysis can be used directly for fuel cells and industrial purposes. The review is urgently needed to provide a comprehensive analysis of the current state of water electrolysis technology and its modelling using renewable energy sources. While individual methods have been well documented, there has not been a thorough investigation of these technologies. With the rising demand for environmentally friendly hydrogen production, the review will provide insights into the challenges and issues with electrolysis techniques, capital cost, water consumption, rare material utilization, electrolysis efficiency, environmental impact, and storage and security implications. The objective is to identify current control methods for efficiency improvement that can reduce costs, ensure demand, increase lifetime, and improve performance in a low-carbon energy system that can contribute to the provision of power, heat, industry, transportation, and energy storage. Issues and challenges with electrolysis techniques, capital cost, water consumption, rare material utilization, electrolysis efficiency, environmental impact, and storage and security implications have been discussed and analysed. The primary objective is to explicitly outline the present state of electrolysis technology and to provide a critical analysis of the modelling research that had been published in recent literatures. The outcome that emerges is one of qualified promise: hydrogen is well-established in particular areas, such as forklifts, and broader applications are imminent. This evaluation will bring more research improvements and a road map to aid in the commercialization of the water electrolyser for hydrogen production. All the insights revealed in this study will hopefully result in enhanced efforts in the direction of the development of advanced hydrogen electrolyser technologies towards clean, sustainable, and green energy.

Flamm et al.: Electrolyzer modeling and real-time control for optimized production of hydrogen gas

Benjamin Flamm, Christian Peter, Felix N. Büchi, and John Lygeros. "Electrolyzer modeling and real-time control for optimized production of hydrogen gas". In: *Applied Energy* 281 (Jan. 1, 2021). Publisher: Elsevier, p. 116031. ISSN: 0306-2619. DOI: 10.1016/J.APENERGY.2020.116031.

Abstract: We present a method that operates an electrolyzer to meet the demand of a hydrogen refueling station in a cost-effective manner by solving a model-based optimal control problem. To formulate the underlying problem, we first conduct an experimental characterization of a Siemens SILYZER 100 polymer electrolyte membrane electrolyzer with 100 kW of rated power. We run experiments to determine the electrolyzer's conversion efficiency and thermal dynamics as well as the overload-limiting algorithm used in the electrolyzer. The resulting detailed nonlinear models are used to design a real-time optimal controller, which is then implemented on the actual system. Each minute, the controller solves a deterministic, receding-horizon problem which seeks to minimize the cost of satisfying a given hydrogen demand, while using a storage tank to take advantage of time-varying electricity prices and photovoltaic inflow. We illustrate in simulation the significant cost reduction achieved by our method compared to others in the literature, and then validate our method by demonstrating it in real-time operation on the actual system.

Tuinema et al.: Modelling of large-sized electrolysers for real-time simulation and study of the possibility of frequency support by electrolysers

Bart W. Tuinema, Ebrahim Adabi, Patrick K.S. Ayivor, Víctor García Suárez, Lian Liu, Arcadio Perilla, Zameer Ahmad, José Luis Rueda Torres, Mart A.M.M. Van Der Meijden, and Peter Palensky. "Modelling of large-sized electrolysers for real-time simulation and study of the possibility of frequency support by electrolysers". In: *IET Generation, Transmission & Distribution* 14.10 (May 1, 2020). Publisher: The Institution of Engineering and Technology, pp. 1985–1992. ISSN: 1751-8695. DOI: `10.1049/IET-GTD.2019.1364`.

Abstract: Hydrogen as an energy carrier holds promising potential for future power systems. An excess of electrical power from renewables can be stored as hydrogen, which can be used at a later moment by industries, households or the transportation system. The stability of the power system could also benefit from electrolysers as these have the potential to participate in frequency and voltage support. Although some electrical models of small electrolysers exist, practical models of large electrolysers have not been described in literature yet. In this publication, a generic electrolyser model is developed in RSCAD, to be used in real-time simulations on the real-time digital simulator. This model has been validated against field measurements of a 1 MW pilot electrolyser installed in the northern part of The Netherlands. To study the impact of electrolysers on power system stability, various simulations have been performed. These simulations show that electrolysers have a positive effect on frequency stability, as electrolysers are able to respond faster to frequency deviations than conventional generators.

3 Coupling electricity and gas models

Blanco-Martínez et al.: Optimization of Interconnected Natural Gas and Power Systems Using Mathematical Programs with Complementarity Constraints

Cristian Alejandro Blanco-Martínez, Andrés Marino Álvarez-Meza, Germán Castellanos-Dominguez, David Augusto Cárdenas-Peña, and Álvaro Angel Orozco-Gutiérrez. "Optimization of Interconnected Natural Gas and Power Systems Using Mathematical Programs with Complementarity Constraints". In: *Mathematics* 12.14 (July 16, 2024). Publisher: MDPI AG, p. 2224. ISSN: 2227-7390. DOI: `10.3390/math12142224`.

Abstract: The demand for thermal power generation from natural gas has increased globally due to its cleaner burning properties compared to other fossil fuels. Optimizing the gas flow through the network to meet this demand is challenging due to the nonconvex Weymouth equation constraining gas flow and nodal pressures in pipelines. Traditional methods for addressing this nonconvexity lead to significant approximation errors or high operational costs. This study poses the Weymouth constraint as a Mathematical Programming with Complementarity Constraints (MPCC) for an optimal gas flow problem. The complementarity constraints reformulate the discontinuous sign function using binary-behaving continuous variables. This MPCC-based approach avoids solving mixed-integer programming problems while enhancing the accuracy of conventional linear and second-order approximations. Testing the approach on various interconnected systems, including Colombia's national gas transportation grid, demonstrated significant reductions in Weymouth approximation errors, thereby supporting effective optimization for interconnected networks.

Chen et al.: Equilibria in Electricity and Natural Gas Markets with Strategic Offers and Bids

Sheng Chen, Antonio J. Conejo, Ramteen Sioshansi, and Zhinong Wei. "Equilibria in Electricity and Natural Gas Markets with Strategic Offers and Bids". In: *IEEE Transactions on Power Systems* 35.3 (May 1, 2020). Publisher: Institute of Electrical and Electronics Engineers Inc., pp. 1956–1966. ISSN: 15580679. DOI: 10.1109/TPWRS.2019.2947646.

Abstract: We study market equilibria that are achieved by strategic firms that participate in electricity and natural gas markets. Strategic firms submit their offers and bids to both markets with the aim of maximizing profit or utility and we consider firms that can include a combination of electricity and natural gas supply and demand. The strategic actions of these firms are represented by upper-level problems that are optimized subject to shared lower-level problems that represent the clearing of electricity and natural gas markets. This market structure and our modeling approach yields a multiple-leader/two-follower complementarity problem. We develop a modeling approach that can find equilibria with different characteristics, e.g., maximized social welfare, producer profits, or consumer welfare. We demonstrate numerically that producers aim typically to increase market prices while consumers seek to decrease them.

Chiang et al.: Emerging optimal control models and solvers for interconnected natural gas and electricity networks

Nai Yuan Chiang and Victor M. Zavala. "Emerging optimal control models and solvers for interconnected natural gas and electricity networks". In: *Alternative Energy Sources and Technologies: Process Design and Operation* (Jan. 1, 2016). Publisher: Springer International Publishing ISBN: 9783319287522, pp. 89–115. DOI: 10.1007/978-3-319-28752-2_4.

Abstract: This chapter reviews emerging optimal control models for interconnected natural gas and electricity networks and discusses economic drivers motivating the development of such models. We also review computational patterns and structures arising in these models and assess the potential and limitations of state-of-the-art optimization solvers.

Chiang et al.: Large-scale optimal control of interconnected natural gas and electrical transmission systems

Nai Yuan Chiang and Victor M. Zavala. "Large-scale optimal control of interconnected natural gas and electrical transmission systems". In: *Applied Energy* 168 (Apr. 15, 2016). Publisher: Elsevier Ltd, pp. 226–235. ISSN: 03062619. DOI: 10.1016/J.APENERGY.2016.01.017.

Abstract: We present a detailed optimal control model that captures spatiotemporal interactions between gas and electric transmission networks. We use the model to study flexibility and economic opportunities provided by coordination. A large-scale case study in the Illinois system reveals that coordination can enable the delivery of significantly larger amounts of natural gas to the power grid. In particular, under a coordinated setting, gas-fired generators act as distributed demand response resources that can be controlled by the gas pipeline operator. This enables more efficient control of pressures and flows in space and time and overcomes delivery bottlenecks. We demonstrate that the additional flexibility not only can benefit the gas operator but can also lead to more efficient power grid operations and results in increased revenue for gas-fired power plants. We also use the optimal control model to analyze computational issues arising in these complex models. We demonstrate that the interconnected Illinois system with full physical resolution gives rise to a highly nonlinear optimal control problem with 4400 differential and algebraic equations and 1040 controls that can be solved with a state-of-the-art sparse optimization solver.

Conejo et al.: Operations and Long-Term Expansion Planning of Natural-Gas and Power Systems: A Market Perspective

By Antonio J. Conejo, Sheng Chen, and Gonzalo E. Constante. "Operations and Long-Term Expansion Planning of Natural-Gas and Power Systems: A Market Perspective". In: *Proceedings of the IEEE* 108.9 (Sept. 1, 2020). Publisher: Institute of Electrical and Electronics Engineers Inc., pp. 1541–1557. ISSN: 15582256. DOI: 10.1109/JPROC.2020.3005284.

Abstract: Natural-gas and power systems are increasingly interdependent due to the integration of an increasing number of combined cycle gas turbines in the power generation mix. However, natural gas and power systems are generally independently operated. This is the result of history and the fact that natural gas has not been important for electricity production until recently. Adopting a power system perspective, this article reviews in a tutorial manner models for the operations and long-term expansion planning of interdependent but independently operated natural-gas and power systems.

Dai et al.: A Static Equivalent Model of Natural Gas Network for Electricity–Gas Co-Optimization

Wei Dai, Juan Yu, Zhifang Yang, Haiyu Huang, Wei Lin, and Wenyuan Li. "A Static Equivalent Model of Natural Gas Network for Electricity–Gas Co-Optimization". In: *IEEE Transactions on Sustainable Energy* 11.3 (2020), pp. 1473–1482. DOI: 10.1109/TSTE.2019.2927837.

Abstract: For the privacy concern, the data exchange between the electricity network and the natural gas network is not always possible. It brings challenges for the co-operation of electricity-gas systems. This paper proposes a static equivalent model that replaces the natural gas network, which lays the foundation for electricity-gas co-operation between separate electricity and gas companies. The influence of the natural gas network on the electricity network is represented in this equivalent model, which consists of a constraint equivalent model and a loss equivalent model. In the constraint equivalent model, a set of optimization models is formulated to approximate the feasible region of natural gas-fired units (NGUs) imposed by the operational constraints of the natural gas network. In the loss equivalent model, the natural gas consumption of compressors contributed by NGUs is considered based on the "shortest path principle" using the gas loss as the weight. The proposed static equivalent model is applied in the optimal power flow of electricity-gas systems. Case studies demonstrate the desired accuracy of the proposed method.

Duan et al.: Distributed optimization of integrated electricity-natural gas distribution networks considering wind power uncertainties

Jiandong Duan, Yao Yang, and Fan Liu. "Distributed optimization of integrated electricity-natural gas distribution networks considering wind power uncertainties". In: *International Journal of Electrical Power & Energy Systems* 135 (Feb. 2022). Publisher: Elsevier BV, p. 107460. ISSN: 0142-0615. DOI: `10.1016/j.ijepes.2021.107460`.

Abstract: In recent years, the penetration of decentralized wind power generation in distribution networks has increased rapidly, and the uncertainties in wind power generation has posed great challenges on the operation of distribution networks. To this end, this paper establishes a distributed coordinated optimization model of integrated electricity-gas distribution networks considering power-to-gas (P2G) units and gas turbines to deal with the uncertainties of wind power output. First, this paper uses chance constraints to deal with the uncertainties of wind power output and converts it into a linear model that is easy to be solved. Secondly, considering the electricity distribution network and gas distribution network as different stakeholders, optimization models are established with the objectives of minimizing their respective operating costs, and the established models are solved in a distributed manner through the analytical target cascading (ATC). Finally, an integrated electricity-gas distribution system composed of the IEEE 33-node distribution network and 24-node natural gas network is used for simulation, which validate the proposed model and method.

Dvurechensky et al.: A Cournot-Nash Model for a Coupled Hydrogen and Electricity Market

Pavel Dvurechensky, Caroline Geiersbach, Michael Hintermüller, Aswin Kannan, Stefan Kater, and Gregor Zöttl. *A Cournot-Nash Model for a Coupled Hydrogen and Electricity Market.* arXiv.org. Oct. 27, 2024. URL: `https://arxiv.org/abs/2410.20534v1` (visited on 03/18/2025).

Abstract: We present a novel model of a coupled hydrogen and electricity market on the intraday time scale, where hydrogen gas is used as a storage device for the electric grid. Electricity is produced by renewable energy sources or by extracting hydrogen from a pipeline that is shared by non-cooperative agents. The resulting model is a generalized Nash equilibrium problem. Under certain

mild assumptions, we prove that an equilibrium exists. Perspectives for future work are presented.

Fokken et al.: Efficient simulation of coupled gas and power networks under uncertain demands

Eike Fokken, Simone Göttlich, and Michael Herty. "Efficient simulation of coupled gas and power networks under uncertain demands". In: *European Journal of Applied Mathematics* 34.3 (2023). Publisher: Cambridge University Press, pp. 505–531. ISSN: 0956-7925. DOI: 10.1017/S0956792522000079. arXiv: 2108.00687.

Abstract: We introduce an approach and a software tool for solving coupled energy networks composed of gas and electric power networks. Those networks are coupled to stochastic fluctuations to address possibly fluctuating demand due to fluctuating demands and supplies. Through computational results, the presented approach is tested on networks of realistic size.

Hosseini et al.: Optimal planning and operation of multi-vector energy networks: A systematic review

Seyed Hamid Reza Hosseini, Adib Allahham, Sara Louise Walker, and Phil Taylor. "Optimal planning and operation of multi-vector energy networks: A systematic review". In: *Renewable and Sustainable Energy Reviews* 133 (Nov. 1, 2020). Publisher: Pergamon, p. 110216. ISSN: 1364-0321. DOI: 10.1016/J.RSER.2020.110216.

Abstract: This paper provides a systematic review of recent publications on simulation and analysis of integrated multi-vector energy networks (rather than energy hubs) and carries this out through the lens of energy trilemma. This review is essential for energy research community to move forward in effective manner toward 2050 net zero carbon targets. This paper presents a holistic view of state-of-the-art of research in this field and identifies gaps in knowledge which should be addressed by future research urgently. Furthermore, this paper introduces a taxonomy of energy networks analysis, offering a unified description of findings of relatively large number of publications devoted to the subject. Moreover, this work analyses and classifies current research trends in the field of analysis of energy networks integration, and also identifies future trends in this field. This review serves as a guide to researchers regarding the main findings of energy networks integration evaluated through the lens of energy trilemma. The reviewed papers have been classified into three groups: (i) Operational analysis; (ii) Optimal dispatch; and (iii) Optimal planning. The focus of the paper is energy networks, since they play fundamental role in integrated energy systems and there is a lack of understanding of interactions and interdependencies between multi-vector networks. Also, focus of this paper has been on key findings of published research rather than details of individual energy models. The paper provides useful insights for energy research community by presenting several novel ideas for future research and facilitating the path to a decarbonised economy, due to the fulfilled comprehensive systematic review.

Khatibi et al.: Integrated Electricity and Gas Systems Planning

Masoud Khatibi, Abbas Rabiee, and Amir Bagheri. “Integrated Electricity and Gas Systems Planning: New Opportunities, and a Detailed Assessment of Relevant Issues”. In: *Sustainability* 15.8 (Apr. 13, 2023). Publisher: MDPI AG, p. 6602. ISSN: 2071-1050. DOI: 10.3390/su15086602.

Abstract: Integrated electricity and gas systems (IEGS) with power-to-gas (PtG) units, as novel sector coupling components between electricity and gas systems, have been considered a promising solution for the reliable and economic operation of the integrated energy systems which can effectively reduce the challenges associated with the high penetration of renewable energy sources (RES). To confirm the economic viability and technical feasibility of the IEGS, its coordinated planning will play a crucial role. The more comprehensive the modeling and evaluation of IEGS planning studies are, the more precise and practical the results obtained will be. In this paper, an in-depth and up-to-date assessment of the available literature on the IEGS planning is presented by addressing critical concerns and challenges, which need further studies. A vast variety of related topics in the IEGS planning, including the impact of costs, constraints, uncertainties, contingencies, reliability, sector coupling components, etc., are also reviewed and discussed. In addition, the role of PtGs and their impacts on the coordinated IEGS planning are reviewed in detail due to their crucial role in increasing the penetration of RES in future energy systems as well as limiting greenhouse gas emissions. The literature review completed by this paper can support planners and policymakers to better realize the bottlenecks in the IEGS development, so that they can concentrate on the remaining unsolved topics as well as the improvement of existing designs and procedures.

F. Li et al.: Deep reinforcement learning-based multi-objective optimization for electricity–gas–heat integrated energy systems

Feng Li, Lei Liu, and Yang Yu. “Deep reinforcement learning-based multi-objective optimization for electricity–gas–heat integrated energy systems”. In: *Expert Systems with Applications* 262 (2025), p. 125558. ISSN: 0957-4174. DOI: 10.1016/j.eswa.2024.125558.

Abstract: With the increasing global attention on energy efficiency and carbon emissions, the optimization of integrated energy systems (IES) has become the key to improve energy efficiency and reduce pollution emissions. However, most of the existing optimization methods cannot effectively deal with the complexity of high dimensional continuous action space. Therefore, this paper focuses on a novel multi-objective optimization strategy for the electricity–gas–heat integrated energy systems (EGH-IES). Firstly, considering the absorption capacity of wind power and the emission of pollutant gases, a multi-objective optimization model is constructed based on the mechanism model and operation constraints of each device in EGH-IES, in which the integrated operation cost and the environmental factors are taken as optimization objectives. Then, the multi-objective optimization problem is designed as the optimal strategy of interaction learning between agent and environment in reinforcement learning, and the output power of the devices constitutes the action of reinforcement learning. Additionally, the Ornstein–Uhlenbeck process is introduced to enhance

the training efficiency and exploration performance of the agent, and the deep deterministic policy gradients (DDPG) algorithm is employed to optimize the action, thus the output power of the appliances could be obtained. Finally, the simulation results show that compared with deep Q network (DQN) method and proximal policy optimization (PPO) method, the reward function value of the proposed method increases by 2.43% and 6.09%, respectively, which represents a reduction in economic cost and pollutant emissions. These verify the effectiveness and superiority of the proposed multi-objective optimization scheme in cost reduction and benefit improvement for the EGH-IES.

J. Li et al.: Optimal Investment of Electrolyzers and Seasonal Storages in Hydrogen Supply Chains Incorporated With Renewable Electric Networks

Jiarong Li, Jin Lin, Hongcai Zhang, Yonghua Song, Gang Chen, Lijie Ding, and Danxi Liang. "Optimal Investment of Electrolyzers and Seasonal Storages in Hydrogen Supply Chains Incorporated With Renewable Electric Networks". In: *IEEE Transactions on Sustainable Energy* 11.3 (2020), pp. 1773–1784. DOI: `10.1109/TSTE.2019.2940604`.

Abstract: Converting surplus renewable electricity into hydrogen by electrolyzers has been recognized as a promising scheme to reduce renewable energy spillage and to meet the increasing hydrogen demand. However, the scheme is challenged by the inherent spatiotemporal imbalance between renewable energy and hydrogen demand. Seasonal storages and interregional hydrogen supply chains (HSCs) are commonly employed in the literature to eliminate this imbalance, but long-distance hydrogen transportation can be costly. In this paper, we incorporated the electric network (EN) into the HSC for its ability to promptly and economically deliver energy at long distances. The uniform hierarchical time discretization method is utilized to achieve the unified operation of the HSC and the EN. On this basis, an integrated HSC-EN model is elaborated upon to investigate the optimal investment and operation of electrolyzers and storage. Finally, an industrial case in Sichuan province, China is analyzed to illustrate the benefits of incorporating the EN to reduce the investment cost and improve electrolyzers' utilization.

Y. Li et al.: Optimal stochastic operation of integrated low-carbon electric power, natural gas, and heat delivery system

Yong Li, Yao Zou, Yi Tan, Yijia Cao, Xindong Liu, Mohammad Shahidehpour, Shiming Tian, and Fanpeng Bu. "Optimal stochastic operation of integrated low-carbon electric power, natural gas, and heat delivery system". In: *IEEE Transactions on Sustainable Energy* 9.1 (Jan. 1, 2018). Publisher: Institute of Electrical and Electronics Engineers Inc., pp. 273–283. ISSN: 19493029. DOI: `10.1109/TSTE.2017.2728098`.

Abstract: Integrated energy system is important for the high-efficient utilization of multitype energy systems. In this paper, the stochastic optimal operation is investigated for the micro integrated electric power, natural gas, and heat delivery system (IPGHS). First, a low-carbon micro-IPGHS is proposed with the comprehensive consideration of renewable generation, carbon-capture-based power-to-gas technology, and the combined power and heat units. Second, a scenario-based optimal operation model for micro-IPGHS is proposed to handle uncertainties in energy demand and renewable generation. In the proposed model, energy transactions between micro-IPGHS and upstream energy systems as well as constraints for battery storage, natural gas storage, and heat storage systems are considered. Finally, a case study is used for the proposed low-carbon micro-IPGHS to validate the optimal stochastic operation approach. The proposed integrated system can effectively utilize the variable clean energy for optimizing the delivery of the green operation in micro-IPGHS.

Liu et al.: Optimal Low-Carbon Economic Environmental Dispatch of Hybrid Electricity-Natural Gas Energy Systems Considering P2G

Jing Liu, Wei Sun, and Gareth P. Harrison. "Optimal Low-Carbon Economic Environmental Dispatch of Hybrid Electricity-Natural Gas Energy Systems Considering P2G". In: *Energies* 12.7 (2019). ISSN: 1996-1073. DOI: 10.3390/en12071355.

Abstract: Power to gas facilities (P2G) could absorb excess renewable energy that would otherwise be curtailed due to electricity network constraints by converting it to methane (synthetic natural gas). The produced synthetic natural gas can power gas turbines and realize bidirectional energy flow between power and natural-gas systems. P2G, therefore, has significant potential for unlocking inherent flexibility in the integrated system, but also poses new challenges of increased system complexity. A coordinated operation strategy that manages power and natural-gas network constraints together is essential to address such challenges. In this paper, a novel low-carbon economic environmental dispatch strategy is presented considering all the constraints in both systems. The multi-objective black-hole particle swarm optimization algorithm (MOBHPSO) is adopted. In addition to P2G, a gas demand management strategy is proposed to support gas flow balance. A new solving approach that combines the effective redundancy method, trust region method, and Levenberg-Marquardt method is proposed to address the complex coupled constraints. Case studies that use an integrated IEEE 39-bus power and Belgian high-calorific 20-node gas system demonstrate the effectiveness and scalability of the proposed model and optimization method. The analysis of dispatch results illustrates the benefit of P2G for the wind power accommodation, and low-carbon, economic, and environmental improvement of integrated system operation.

Pambour et al.: Development of a Simulation Framework for Analyzing Security of Supply in Integrated Gas and Electric Power Systems

Kwabena Addo Pambour, Burcin Cakir Erdener, Ricardo Bolado-Lavin, and Gerard P.J. Dijkema. "Development of a Simulation Framework for Analyzing Security of Supply in Integrated Gas and Electric Power Systems". In: *Applied Sciences 2017, Vol. 7, Page 47* 7.1 (Jan. 5, 2017). Publisher: Multidisciplinary Digital Publishing Institute, p. 47. ISSN: 2076-3417. DOI: 10.3390/APP7010047.

Abstract: Gas and power networks are tightly coupled and interact with each other due to physically interconnected facilities. In an integrated gas and power network, a contingency observed in one system may cause iterative cascading failures, resulting in network wide disruptions. Therefore, understanding the impacts of the interactions in both systems is crucial for governments, system operators, regulators and operational planners, particularly, to ensure security of supply for the overall energy system. Although simulation has been widely used in the assessment of gas systems as well as power systems, there is a significant gap in simulation models that are able to address the coupling of both systems. In this paper, a simulation framework that models and simulates the gas and power network in an integrated manner is proposed. The framework consists of a transient model for the gas system and a steady state model for the power system based on AC-Optimal Power Flow. The gas and power system model are coupled through an interface which uses the coupling equations to establish the data exchange and coordination between the individual models. The bidirectional interlink between both systems considered in this studies are the fuel gas offtake of gas fired power plants for power generation and the power supply to liquefied natural gas (LNG) terminals and electric drivers installed in gas compressor stations and underground gas storage facilities. The simulation framework is implemented into an innovative simulation tool named SAInt (Scenario Analysis Interface for Energy Systems) and the capabilities of the tool are demonstrated by performing a contingency analysis for a real world example. Results indicate how a disruption triggered in one system propagates to the other system and affects the operation of critical facilities. In addition, the studies show the importance of using transient gas models for security of supply studies instead of successions of steady state models, where the time evolution of the line pack is not captured correctly.

Schwele et al.: Coordination of power and natural gas systems: Convexification approaches for linepack modeling

Anna Schwele, Christos Ordoudis, Jalal Kazempour, and Pierre Pinson. "Coordination of power and natural gas systems: Convexification approaches for linepack modeling". In: *2019 IEEE Milan PowerTech, PowerTech 2019* (June 1, 2019). Publisher: Institute of Electrical and Electronics Engineers Inc. ISBN: 9781538647226. DOI: 10.1109/PTC.2019.8810632.

Abstract: Utilizing operational flexibility from natural gas networks can foster the integration of uncertain and variable renewable power production. We model a combined power and natural gas dispatch to reveal the maximum potential of linepack, i.e., energy storage in the pipelines, as a source of flexibility for the power system. The natural gas flow dynamics are approximated by a combination of steady-state equations and varying incoming and outgoing flows in the pipelines to account for both natural gas transport and linepack. This steady-state natural gas flow results in a nonlinear and nonconvex formulation. To cope with the computational challenges, we explore convex quadratic relaxations and linear approximations. We propose a novel mixed-integer second-order cone formulation including McCormick relaxations to model the bidirectional natural gas flow accounting for linepack. Flexibility is quantified in terms of system cost compared to a dispatch model that either neglects linepack or assumes infinite storage capability.

Tan et al.: Dispatching optimization model of gas-electricity virtual power plant considering uncertainty based on robust stochastic optimization theory

Zhongfu Tan, Wei Fan, Hanfang Li, Gejirifu De, Jiale Ma, Shenbo Yang, Liwei Ju, and Qingkun Tan. "Dispatching optimization model of gas-electricity virtual power plant considering uncertainty based on robust stochastic optimization theory". In: *Journal of Cleaner Production* 247 (2020), p. 119106. ISSN: 0959-6526. DOI: `10.1016/j.jclepro.2019.119106`.

Abstract: With the rapid development of renewable energy, virtual power plant technology has gradually become a key technology to solve the large-scale development of renewable energy. This paper focuses on the stochastic dispatching optimization of gas-electric virtual power plant (GVPP). Based on this, wind power plant, photovoltaic power generation and convention gas turbines are used as the power generation side of GVPP. Power-to-gas (P2G) equipment and gas storage tank can realize the conversion and storage of electricity-gas energy. Price based demand response and incentive based demand response are introduced into the terminal load side to regulate the user's electricity consumption behavior. GVPP bilaterally connects power network and natural gas network, which realizes the bidirectional flow of electricity-gas energy. Firstly, taking the maximization of economic benefits as the objective function, combined with the constraints of power balance, system reserve and so on, a dispatching optimization model of GVPP participating in multi-energy markets is constructed to determine the operation strategy. Secondly, wind, solar and other clean energy have the characteristics of random and fluctuation, which threaten the stable operation of the system. Therefore, a stochastic dispatching optimization model of GVPP considering wind and solar uncertainty is established based on robust stochastic optimization theory. Thirdly, the evaluation indicators of GVPP operation is determined, which can comprehensively evaluate the economic benefits, environmental benefits and system operation of virtual power plant. Finally, in order to verify the validity and feasibility of the model, a virtual power plant is selected for example analysis. The results show that: (1) After the implementation of price based demand response and incentive based demand response, the system load variance changes from 0.03 to 0.013. Through the comparison of load curves, it is found that demand response can play a role of peak-shaving and valley-filling and smooth the power load curve; (2) Stochastic optimization theory can overcome the uncertainty of wind and solar by setting different robust coefficients Γ which reflects the ability of the system to withstand risks; (3) The optimization effect after introducing the P2G subsystem makes the amount of abandoned clean energy close to zero. The operation risk of system is reduced, and the carbon emissions are reduced by 370 m3 too. The market space is expanded from electricity market mainly to natural gas market and carbon trading market.

Yan et al.: Wind electricity-hydrogen-natural gas coupling: An integrated optimization approach for enhancing wind energy accommodation and carbon reduction

Yamin Yan, Yumeng Wang, Jie Yan, Haoran Zhang, and Wenlong Shang. "Wind electricity-hydrogen-natural gas coupling: An integrated optimization approach for enhancing wind energy accommodation and carbon reduction". In: *Applied Energy* 369 (2024), p. 123482. ISSN: 0306-2619. DOI: 10.1016/j.apenergy.2024.123482.

Abstract: Utilizing renewable energy for hydrogen production and blending it into natural gas networks is recognized as a promising approach to promote a low-carbon transformation of power systems and enhance the integration of renewable energy sources. However, the temporal and geographical availability of renewable energy and natural gas operation conditions vary greatly, emphasizing the importance of precise planning and operational strategies for the renewable energy-hydrogen-natural gas coupling system. This article introduces a smart design and operational strategy for a wind electricity-hydrogen-natural gas coupling system aimed at enhancing renewable energy accommodation. The primary objectives are to evaluate the technical and economic feasibility of such coupling systems and to determine the optimal planning and operation strategies for hydrogen production, transportation, and blending into natural gas networks while minimizing total investment and operational costs. By utilizing real curtailed electricity data and natural gas pipeline network operating flow rate data, the potential of this coupling system to enhance renewable energy accommodation and reduce carbon emissions is explored. The results indicate that this optimized coupling system can accommodate 20.11% of curtailed wind electricity and reduce carbon emissions by 1.05 billion tons per year. Additionally, the impact of hydrogen blending ratios and hydrogen prices on the economic and environmental performance of the coupling system is also investigated. Improving the hydrogen blending ratio is the key to enlarging the economic and environmental performance of the coupling system, but the hydrogen sale price has a negligible impact on the renewable energy accommodation and environmental performance of the coupling system.

Yueksel-Erguen et al.: Modeling the transition of the multimodal pan-European energy system including an integrated analysis of electricity and gas transport

Inci Yueksel-Erguen, Dieter Most, Lothar Wyrwoll, Carlo Schmitt, and Janina Zittel. "Modeling the transition of the multimodal pan-European energy system including an integrated analysis of electricity and gas transport". In: *Energy Systems* (2023). Publisher: Springer Science and Business Media Deutschland GmbH. ISSN: 18683975. DOI: 10.1007/s12667-023-00637-5.

Abstract: Most recently, the European energy system has undergone a fundamental transformation to meet decarbonization targets without compromising the security of the energy supply. The transition involves several energy-generating and consuming sectors emphasizing sector coupling. The increase in the share of renewable energy sources has revealed the need for flexibility in supporting the electricity grid to cope with the resulting high degree of uncertainty. The new technologies accompanying the energy system transition and the recent political crisis in Europe threatening the security of the energy supply have invalidated the experience from the past by drastically changing the conventional scenarios. Hence, supporting strategic planning tools with detailed operational energy network models with appropriate mathematical precision has become more important than ever to understand the impacts of these disruptive changes.

In this paper, we propose a workflow to investigate optimal energy transition pathways considering sector coupling. This workflow involves an integrated operational analysis of the electricity market, its transmission grid, and the gas grid in high spatio-temporal resolution. Thus, the workflow enables decision-makers to evaluate the reliability of high-level models even in case of disruptive events. We demonstrate the capabilities of the proposed workflow using results from a pan-European case study. The case study, spanning 2020–2050, illustrates that feasible potential pathways to carbon neutrality are heavily influenced by political and technological constraints. Through integrated operational analysis, we identify scenarios where strategic decisions become costly or infeasible given the existing electricity and gas networks.

Zhang et al.: Optimization of integrated energy system considering transmission and distribution network interconnection and energy transmission dynamic characteristics

Yumin Zhang, Xuan Zhang, Xingquan Ji, Xueshan Han, and Ming Yang. "Optimization of integrated energy system considering transmission and distribution network interconnection and energy transmission dynamic characteristics". In: *International Journal of Electrical Power & Energy Systems* 153 (Nov. 2023). Publisher: Elsevier BV, p. 109357. ISSN: 0142-0615. DOI: `10.1016/j.ijepes.2023.109357`.

Zheng et al.: Energy Flow Optimization of Integrated Gas and Power Systems in Continuous Time and Space

Chao Zheng, Jiakun Fang, Shaorong Wang, Xiaomeng Ai, Zhou Liu, and Zhe Chen. "Energy Flow Optimization of Integrated Gas and Power Systems in Continuous Time and Space". In: *IEEE Transactions on Smart Grid* 12.3 (May 2021). Publisher: Institute of Electrical and Electronics Engineers (IEEE), pp. 2611–2624. ISSN: 1949-3053, 1949-3061. DOI: `10.1109/tsg.2020.3044609`.

Abstract: Due to the increasing penetration of gas-fired units and power to gas facilities, the electrical power system and natural gas system are more and more bi-directionally coupled. To tackle the challenges on the optimal scheduling operation of an integrated gas and power systems (IGPS), this article focuses on developing a novel approach to build a continuous spatial-temporal optimal operation schedule model. In the light of different time constants of the electrical power and natural gas systems, the continuous spatial-temporal optimal operation schedule model of IGPS is formulated in function space. Additionally, Bernstein polynomials are used to reformulate the continuous spatial-temporal optimization problem of IGPS to mixed-integer linear programming. In the study cases, the simulation results of a simple integrated system and a combined IEEE 39-bus power system and Belgian natural gas network demonstrate the accuracy and effectiveness of the proposed model.

Zlotnik et al.: Coordinated Scheduling for Interdependent Electric Power and Natural Gas Infrastructures

Anatoly Zlotnik, Line Roald, Scott Backhaus, Michael Chertkov, and Goran Andersson. "Coordinated Scheduling for Interdependent Electric Power and

Natural Gas Infrastructures”. In: *IEEE Transactions on Power Systems* 32.1 (Jan. 2017). Publisher: Institute of Electrical and Electronics Engineers (IEEE), pp. 600–610. ISSN: 0885-8950, 1558-0679. DOI: 10.1109/tpwrs.2016.2545522.

Abstract: The extensive installation of gas-fired power plants in many parts of the world has led electric systems to depend heavily on reliable gas supplies. The use of gas-fired generators for peak load and reserve provision causes high intraday variability in withdrawals from high-pressure gas transmission systems. Such variability can lead to gas price fluctuations and supply disruptions that affect electric generator dispatch, electricity prices, and threaten the security of power systems and gas pipelines. These infrastructures function on vastly different spatio-temporal scales, which prevents current practices for separate operations and market clearing from being coordinated. In this paper, we apply new techniques for control of dynamic gas flows on pipeline networks to examine day-ahead scheduling of electric generator dispatch and gas compressor operation for different levels of integration, spanning from separate forecasting, and simulation to combined optimal control. We formulate multiple coordination scenarios and develop tractable physically accurate computational implementations. These scenarios are compared using an integrated model of test networks for power and gas systems with 24 nodes and 24 pipes, respectively, which are coupled through gas-fired generators. The analysis quantifies the economic efficiency and security benefits of gas-electric coordination and dynamic gas system operation.

CATAPULT
Energy Systems

Accelerate Net Zero
energy innovation

FOGSI
Planning the UK hydrogen network

[redacted]
Consumer Research Manager

January 2026

Acronyms and abbreviations

CAA	Civil Aviation Authority
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CapEx	Capital Expenditure
CSNP	Centralised Strategic Network Plan
FEED	Front-End Engineering Design
FOGSI	Future Operability of Gas for System Integration
GoO	Guarantees of Origin
HAR	Hydrogen Allocation Round
LHV	Low Heating Value
NGT	National Gas Transmission
OEM	Original Equipment Manufacturer
SAF	Sustainable Aviation Fuel
SSEP	Strategic Spatial Energy Planning

Contents

Executive Summary

The Future Operability of Gas for System Integration (FOGSI) project aims to **develop an integrated hierarchical network modelling framework to simulate future Great Britain (GB) energy system scenarios where gas and electricity networks are highly interconnected.**

To support this aim, Energy Systems Catapult engaged hydrogen producers and end users in hard-to-decarbonise sectors (e.g., heavy industry, aviation, maritime) to identify technical specifications and broader requirements for connecting to a national hydrogen network. This report will inform modelling and highlight key policy and market interventions that will unlock the potential of the national hydrogen network.

Research revealed that **uncertainty is the biggest barrier to progress**, with both producers and off-takers being unable to provide high certainty estimates and definite technical requirements for connecting to the network. Lack of clarity around policy, funding, demand, supply, and grid connection is turning potential enablers into obstacles, leaving stakeholders to advance projects at significant risk. The absence of a national hydrogen pipeline network further complicates operations, forcing reliance on local infrastructure and increasing costs. While **a national network could help break the chicken-and-egg cycle between production and demand, a perceived lack of communication about its rollout erodes trust and amplifies uncertainty.**

To address these challenges, the report recommends exploring ways to reduce uncertainty around policy, funding, and demand, and most importantly, **providing stakeholders with a clear, high-level and long-term roadmap** for infrastructure rollout, enabling them to align plans and invest with confidence. This final recommendation is the most feasible in the near term and has the potential to deliver meaningful impact, as it could **help provide greater certainty across the industry.** Furthermore, the fact that some stakeholders suggested ideas or policies that already exist reinforces the **need to share more information with them.**

Introduction

The FOGSI project is exploring how Great Britain's energy system can evolve as gas and electricity networks become increasingly interconnected. **Decarbonising hard-to-abate sectors such as heavy industry, aviation, and maritime will require new infrastructure and technologies, including hydrogen networks.**

This report presents the findings of in-depth stakeholder engagement conducted by Energy Systems Catapult to **understand what hydrogen producers and users need in order to connect to a national hydrogen network** and to support the progression of hydrogen development in the UK. The research involved a literature review to define the hydrogen stakeholder archetypes to be engaged, followed by a mixed-method approach (quantitative and qualitative research) to engage them. The insights gathered will inform the design of an integrated modelling framework, supporting accurate planning for future hydrogen infrastructure deployment that works for both hydrogen producers and users. The findings reflect stakeholders' perceptions rather than an evaluation of sector performance.

The following sections outline the methodology, key takeaways, detailed insights from stakeholder engagement, and conclusions with **recommendations to address barriers and enable hydrogen development as part of GB's Net Zero transition**.

Methodology

- For this project, the first step was to execute a literature review that helped us define what archetypes of stakeholders we would be engaging. After agreeing with the wider consortium on them, we adopted a mixed-methods approach, combining quantitative and qualitative techniques to involve them and capture both the *what* and *why:*

  - **Quantitative phase:**
    - Method: 15-minutes online survey
    - Sample: 13 stakeholders (8 hydrogen producers and 5 hydrogen users in the UK)
    - Timeline: October – December 2025
    - Open-text responses were lightly cleaned and standardised for clarity, with no changes to respondents' intended meaning.

  - **Qualitative phase:**
    - Method: Semi-structured online interviews that lasted between 30 and 45 minutes
    - Sample: 7 stakeholders (5 hydrogen producers and 2 hydrogen users in the UK)
    - Timeline: November – December 2025

Additionally, National Gas Transmission shared anonymised datasets* from a previous [redacted]. The data had origin [redacted]hrough targeted stakeholder engagement using structured data-capture forms, with the aim of gathering information on the flows of hydrogen users and producers for FEED work. In total, NGT shared data of 62 stakeholders collected between September 2024 and January 2026.

- Informed consent was obtained, and data was anonymised.
- Caveat: This report reflects stakeholder perceptions and experiences. These views may not fully represent the breadth of activity happening across the sector, including work that stakeholders may not be aware of.
- Limitations: Despite strong recruitment leveraging consortium partners' networks, sample size was limited. This reflects the challenge of engaging a small, frequently researched population to provide detailed data on topics with considerable uncertainty. Consequently, quantitative findings should be interpreted with caution.

(*) National Gas' data was converted using LHV (low heating value), to ensure comparability with our data.

Summary of Key Takeaways

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Uncertainty

Uncertainty permeates every key enabler of hydrogen development. **Policies, funding, demand, and grid connections** should act as assets promoting progress, yet they often become barriers.

Stakeholders are **advancing projects at risk**, relying on assumptions to make progress. The greatest vulnerability stems from policy changes, which can trigger financial challenges and jeopardise both projects and companies.

Chicken and egg cycle

As a result, **hydrogen development in the UK is caught in a chicken-and-egg cycle:** off-takers hesitate to switch due to supply insecurity, while producers delay investment because demand remains uncertain.

This situation **has eroded confidence** in the UK's hydrogen infrastructure and the prospect of connecting to a national hydrogen network, forcing stakeholders to **explore alternative pathways** to keep their plans moving.

Risk reduction

Key **levers to address current uncertainties** include long-term planning that is independent of political cycles, reliable and consistent funding, active support for promoting hydrogen, improved communication and information sharing (such as clear timelines and locations for rollout, connection processes, and public awareness).

These actions would also send a strong signal to **boost investment confidence.**

Near term strategies

Stakeholders are currently planning to focus **on local supply/demand, leveraging what is available** and poses less risk to their business.

Regarding the hydrogen network, they recommend prioritising near-term support through a **localised approach:** developing smaller pipelines that connect industries within specific areas (e.g., industrial clusters). This would allow projects to **progress alongside** the national network without having to wait for its completion.

Part 1:
Current situation

“Investment doesn’t like uncertainty”

Stakeholders perceive that uncertainty is the main barrier to advancing hydrogen projects, driven by structural, political, and geographical factors.

Uncertainty permeates every key enabling factor

1 **Policy and Legislation**
These elements are critical for driving market maturity. Current policies (e.g., SSEP, CSNP) are perceived to lack strategic focus on hydrogen transmission and repurposing gas networks. The new hydrogen transport/storage b[redacted]egional [redacted]

2 **Funding Support**
SMEs and non-commercial projects (e.g., hydrogen for aviation) need funding for proof of concept, prototypes, and demonstrators. Current support is valued but remains inconsistent: small, predictable sums are essential while waiting for larger grants. Delays caused by shifting government priorities (e.g., annual funding pushed to biennial), and other financial barriers exacerbate these challenges. [redacted]

3 **Off-Taker Demand**
Securing demand remains challenging despite outreach efforts. The “hard-to-electrify” narrative limits hydrogen demand, pushing some industries towards electrification despite practical constraints (i.e., grid capacity, site conditions, high CapEx, and downtime).

4 **Grid Connection**
The grid is at capacity, stalling hydrogen projects until constraints are resolved. Strengthening and expanding the grid to accommodate renewables and hydrogen is critical for progress.

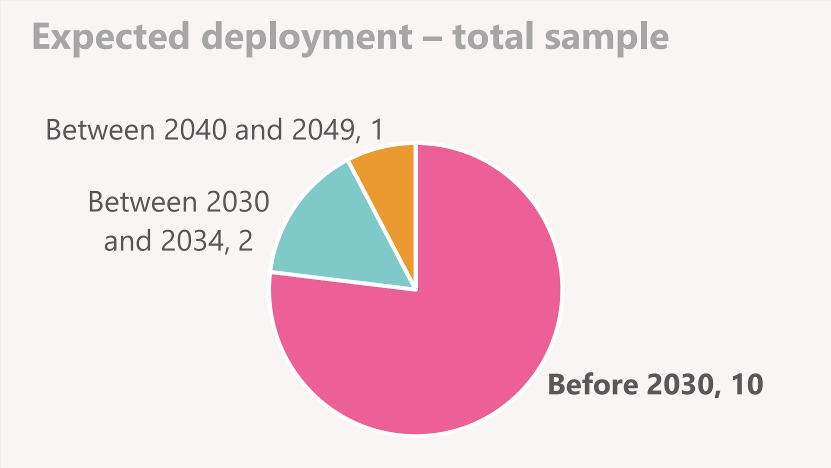
5 **Open Collaboration**
Regional hydrogen clusters support collaboration but remain insufficient. Broader, integrated forums and innovative interactive platforms led by government (or a relevant national body backed by government) are needed for effective knowledge exchange.

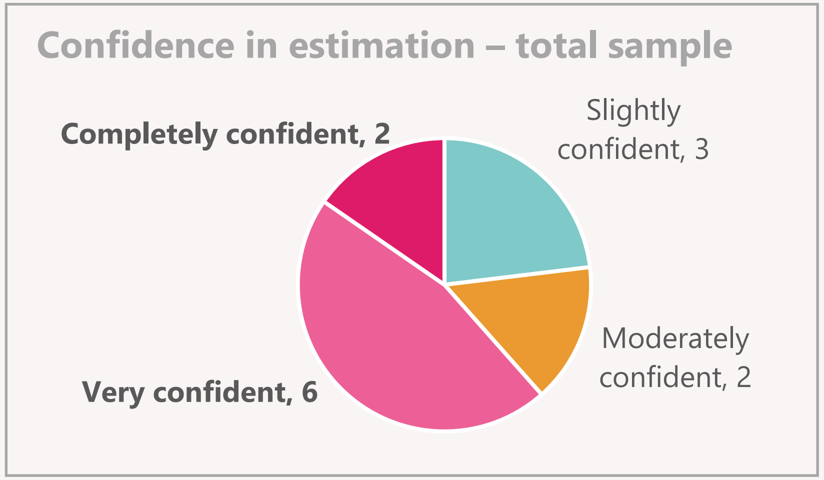
Assumptions are driving progress

Stakeholders continuing to advance their hydrogen projects are doing so based on several key assumptions, which stem from those critical enablers that currently act as barriers:

1. **Policy and funding support** will be available.
2. **There will be a viable market** with sufficient **off-taker demand**.
3. **A national hydrogen pipeline network will exist**, enabling delivery to customers.
4. **Electricity grid capacity** will be accessible.
5. Hydrogen demand will remain relatively low for the first years, **gradually increasing through the 2030s, then accelerating sharply**.

The survey showed that 10 out of 13 stakeholders expect their projects to deploy before 2030, with 8 being very or completely confident in these timelines.





This confidence appears to be based on their own progress and the UK's target to increase hydrogen production by 2030, rather than reflecting current and broader market progress.

Q3. When do you expect your project to deploy? (Total responses: 13)
Q4. How confident are you in this estimation? (Total responses: 13)

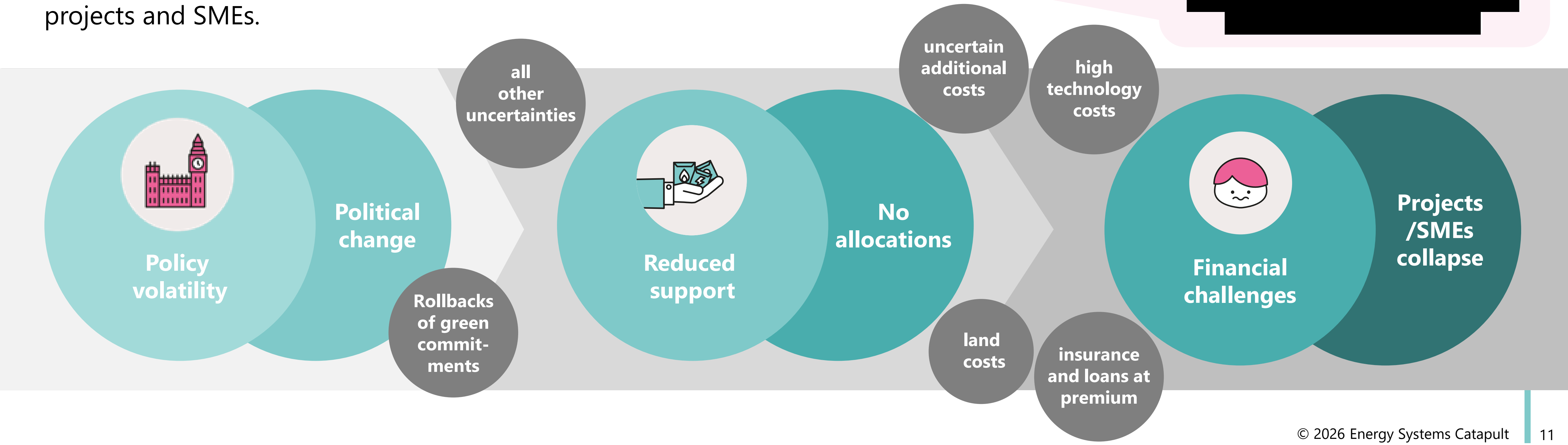
Stakeholders are developing at risk

Policy volatility and inconsistencies (mainly driven by political changes) pose a major risk to the hydrogen sector. These risks could severely harm an already fragile market that faces multiple financial challenges:

- **Funding:** Projects are not bankable without subsidies, and securing financing is difficult.
- **High technology costs:** Equipment and electrolysis costs remain high and have not fallen as expected since 2021.
- **Land competition and costs:** Large sites for projects like wind farms are hard and expensive to secure.
- **Insurance and loans:** Premiums are high due to limited hydrogen awareness and perceived risk.
- **Uncertain additional costs:** For example, H_2 mobility and equipment conversion for off-takers.

As they see it, this could potentially cause financial losses, leave companies with stranded infrastructure, and, most critically, lead to the collapse of projects and SMEs.

[redacted]



Interactions across value chain

To accelerate project development, interviewees reported **actively engaging with stakeholders across the hydrogen value chain**, participating in clusters, and creating collaborative spaces to share knowledge and foster innovation:

For producers, the priority is engaging off-takers. One producer reported being in constant communication, but most struggle, especially with high-priority industries like glass and steel. These sectors demand price clarity, which is difficult to provide given current market uncertainty and unknown demand scale. Producers also interact with a wide range of stakeholders, from OEMs (electrolyser manufacturers) and haulage operators to local councils and government bodies (e.g., through grant programs).

Users revealed they are making significant efforts to engage regionally and nationally with potential producers, transport/liquefaction manufacturers, and even other users (such as SMEs facing similar challenges).

Networking is well advanced for all, and some have even hosted trials. However, **the common gap remains: project deployment.**

Part 2:
Hydrogen network

Proximity will drive hydrogen network connection vs. local production/use

Whether to connect to a national network or produce/use hydrogen locally, stakeholders agree they will choose what is available and makes sense for their business.

- **Producers indicated that decisions will depend on off-taker proximity and cost.**
  - One stakeholder explained that if an off-taker needs hydrogen and they could site locally, then they would; otherwise, they would connect to national hydrogen network to reach distant demand.
- **Users said their choice will depend on location and nearby options.**
  - Another stakeholder noted that while a future pipeline would make more sense for their area, they are open to local supply if a producer emerges nearby.

NATIONAL HYDROGEN NETWORK	LOCAL PRODUCTION/ USE
• Designed for mass transport and industrial-scale projects. • Economies of scale and subsidy focus (which seems to be shifting towards larger projects), can make pipelines more viable.	• Suitable for smaller projects (e.g., ~10 MW, cylinder-based delivery) but is not scalable for mass transport.
• System-level benefits: Northern projects supplying southern demand can help alleviate grid constraints.	• Dedicated local off-takers are hard to secure, which makes local supply less attractive when applying for HAR, as the scheme requires a 15-year supply agreement.
• Reduces risk for off-takers when hydrogen is readily available.	• Potential to use own fleet.
• Connection cost applies if the location is far from the network.	• No connection cost.

Connecting to the hydrogen network is important

Stakeholders agree that a national hydrogen network would connect hubs, producers, and off-takers, enabling hydrogen to move from north to south, easing grid constraints, and reducing costs, especially for long distances compared to boats, trains (where knowledge is perceived as limited), or trucks (considered effective but more expensive).

More importantly, it would signal government commitment and help break the "chicken-and-egg" cycle.

Access to the hydrogen network is important for almost all stakeholders, and essential for a few producers whose projects assume they will inject most or all of their hydrogen into the network, with no alternative plan.

However, while the network is a dependency for a few projects, most producers view it primarily as a potential enabler that could catalyse additional production rather than a critical factor for their current plans.

[redacted]

This stems from the market uncertainty and the lack of mature infrastructure, which have forced many stakeholders to seek alternatives to advance their plans without relying on the national pipeline network. These alternatives include using on-site storage (which has increased costs), or even pivoting to hydrogen derivatives (e.g., green ammonia, SAF) where storage, transport, and market routes already exist.

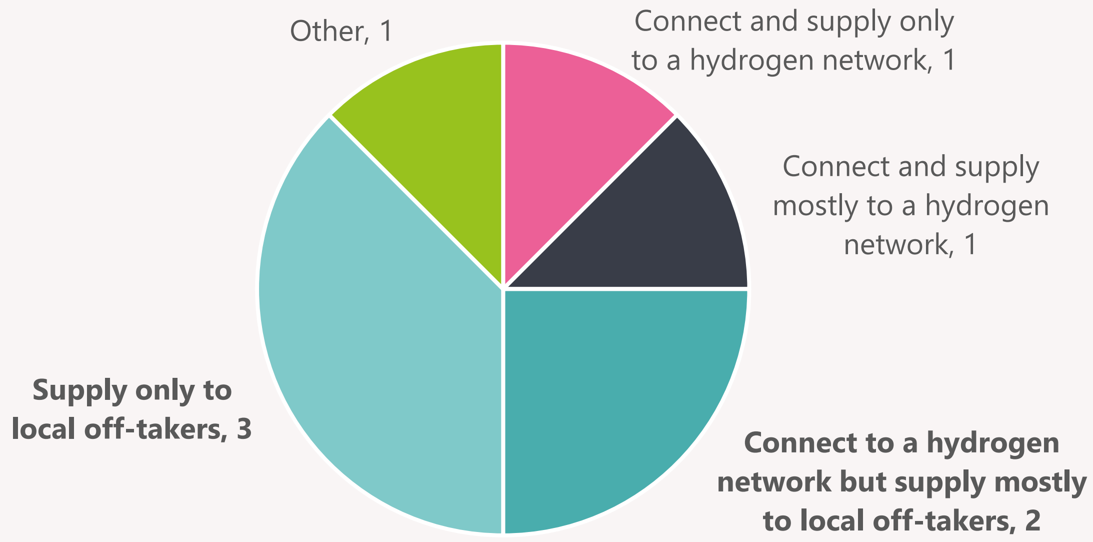
Few stakeholders expect to connect to the national hydrogen network

Stakeholders understand the uses, advantages, and disadvantages of each option and plan to leverage what is available while minimising risks.

The survey found that 5 out of 8 hydrogen producers plan to supply only or mostly to local off-takers. Amongst this group, those expecting to connect to the hydrogen network anticipate delivering just 10–20% of their production to the national network.

As for users, only 1 out of 5 plan to connect to the hydrogen network.

Supply planning



More demand options = more confidence: For producers considering both approaches, access to the hydrogen network acts as a valuable insurance policy, providing flexibility if local off-take is insufficient.

Q13. Do you expect to connect to a hydrogen network or operate locally with a limited number of off-takers? (Total sample: 8)
Q13a. What percentage of your hydrogen production do you expect to supply to the hydrogen network? (Total sample: 8)

How to make it happen

To make connecting to the national hydrogen network more viable, stakeholders need solutions to current uncertainties, turning barriers into potential enablers:

Policies and legislation:
Long-term planning tied to Net Zero targets and independent of political cycles, plus better signposting.

Funding support:
Reliable and regular funding streams and accessible equipment pricing.

Off-taker demand:
Support in actively promoting hydrogen and adopting a balanced approach that recognises its role where electrification is impractical.

Beyond these, another key element emerges:

Communication & Information Sharing

- **Timeline clarity for infrastructure rollout** to enable planning alignment.
- **Visibility of projected pipeline locations** to support planning and budgeting (e.g., estimating connection costs).
- **Clear understanding of connection processes**, ideally analogous to natural gas, keeping details anonymous to protect commercial sensitivities.
- **Desire to understand how support mechanisms (e.g., hydrogen transport and storage business model) interconnect** while remaining standalone, and how cost responsibilities (including storage) are allocated under these arrangements.
- **Public awareness initiatives to improve understanding of hydrogen**, its impacts, and safety, helping normalise hydrogen and reduce perceived risks (e.g., comparisons to nuclear energy). **Greater familiarity within the financial sector could also lower insurance premiums and loan fees as banks become more comfortable with hydrogen projects**.

Addressing these issues would send a strong signal to boost investment confidence.

An interactive platform to connect stakeholders

Beyond improving government communication and information sharing about the national hydrogen network, stakeholders emphasised the need for open collaboration and knowledge exchange, where government also receives data and stakeholders share insights with each other.

In addition to existing forums and clusters, many stakeholders highlighted the need for **an open, shared platform that**:

- Displays projects on an interactive map.
- Uses data collected by government (through consultations) and trade associations.
- Shares details on pipeline routing, location, capacity, volume, and nearby storage infrastructure.
- Keeps all value-chain actors aligned with latest innovations and plans.

Ideally, this platform would be live, dynamic, and allow interaction, enabling:

- Producers to input locations, potential outputs, and timelines.
- Off-takers to access the platform and connect directly with producers.

Such visibility could help reduce uncertainty and link producers with off-takers more efficiently.

Rather than focusing on a single output, the platform can also enable producers and users to match for hydrogen production byproducts (O_2, CO_2, and heat).

One stakeholder noted that something similar is already emerging in Europe: a “Tinder-style” web application where producers post project details and off-takers browse and select, effectively creating matches.

Connecting to a national hydrogen network

Other ideas to support hydrogen network connections include:

- **Logistics-aware planning:** Future pipelines should route through strategic industrial areas/parks to enable direct, metered connections for producers and off-takers, minimising inefficient cylinder transport.

- **Cluster-based policy:** Supporting local industrial clusters with shared energy needs (H_2, O_2, CO_2, waste heat) to enable integrated uses (e.g., oxygen for cement kilns; pairing H_2 + CO_2 for e-fuels in aviation/maritime).

- **Aviation market development:** Early hydrogen routes are non-commercial and aircraft too small for current airport markets. A government-led framework that connects suppliers, regulators, airports and other relevant stakeholders regionally, for coordinating new short, zero-emission routes. This framework, combined with tax incentives, could create minor but viable opportunities.

Part 3:
Looking at the future

Policy changes & market mechanisms needed

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Stakeholders perceive that clarity on policies, regulations, legislation, and supportive mechanisms are essential to reduce the cost and risk of transitioning away from fossil fuels. While some stakeholders believe current policies are helpful, most consider them insufficient, as the market demands more robust measures. In addition to long-term planning that is independent of political cycles, the following actions were emphasised:

- **Hydrogen blending:** Clear policy on blending into transmission pipelines, including permitted levels.
  - Enable blending at the highest feasible level, as current limits are linked to European interconnection constraints.
- **Hydrogen transmission:** Policies with a strategic focus on hydrogen transmission and repurposing gas networks.
- **Carbon-tax:** Establish unambiguous, durable carbon-tax and pricing signals.
- **Standards:** Implement definite and consistent standards for hydrogen.
- **Off-takers:** Provide clear policy guidance for industrial hydrogen users and avoid restrictive policies that "close off roads" for hydrogen demand in certain industries (e.g., manufacturing and healthcare).
- **Funding:** Continue HAR-style funding support but make it long-term and consistent.
  - Define clear pathways for policy and funding support for smaller projects to build supply chains, skills, and confidence.
- **Support Balance:** Ensure policy supports large-scale hydrogen projects while maintaining mechanisms for smaller demonstrations that build supply chains and skills. Without this, practical issues (such as OEMs prioritising left-hand-drive European markets over right-hand-drive hydrogen trucks) could delay UK adoption.
- **Aviation:** Ensure government support aligns with recommendations from the Jet Zero Council/Task Force (Department for Transport and Department for Business and Trade), which are preparing an end-to-end supply chain report.

Standardisation should be driven by off-takers needs

Standardisation is seen as essential to avoid fragmentation and make equipment choices and operations simpler. While there are some concerns about feasibility and cost, these are generally considered minor compared to the bigger challenges already discussed.

The expectation is that hydrogen **standards will be developed collaboratively by government and industry**, ensuring safety, reliability, and smooth integration across the network, and following the example of mature standards in petrol logistics.

Many **producers indicated they can adapt** to pipeline requirements, whereas off-takers may need specific conditions, **suggesting that standards should be based primarily on off-taker needs.**

[redacted]

Reflecting once again that the **uncertainty around the hydrogen infrastructure development in the UK slows down the development of individual hydrogen projects**.

Key aspects to standardise

Although stakeholders were not able to share the specific requirements for connecting to the national hydrogen network, they did identify the aspects that should be prioritised when standardising:

ASPECTS TO PRIORITISE IN STANDARDISATION

1. Hydrogen Quality & Purity	• Consistent purity levels for different applications (e.g., fuel cells, industrial use).
2. Pressure Standards	• Defined pressure tiers similar to natural gas: Transmission level, Medium pressure, Low pressure • Standard pressures for refuelling equipment (aviation and other sectors).
3. Health & Safety Protocols	• Comprehensive safety standards for hydrogen logistics. • Fitness-for-purpose checks at transmission and distribution levels. • Long-term reliability requirements.
4. Connection & Interface Protocols	• Uniform connection designs for pipelines, refuelling stations, and end-use equipment. • Interfaces for handling and storage systems.
5. Handling & Storage	• Standardised cylinder types and materials. • Storage protocols aligned with safety and reliability requirements.
6. Pipeline Repurposing Standards	• Guidelines for assessing existing gas pipelines: age and material suitability for hydrogen transport.
7. Aviation-Specific Standards	• Fuel-quality standards analogous to Jet A-1 for aviation. • Refuelling equipment (hoses, pressures, operational procedures). • Regulatory alignment (European/US regulators like CAA). • Early manufacturer-led designs (e.g., ZeroAvia) may influence initial standards.

International examples

Stakeholders shared some examples of countries advancing on hydrogen development, offering lessons for the UK:

- **Middle East:** Abundant cheap solar enables large-scale "electrons-to-molecules" strategies converting hydrogen into green ammonia for export (e.g., NEOM).
  - Leverage abundant renewables, develop hydrogen derivatives for export, invest in conversion infrastructure.
- **China:** Deploying hydrogen across all sectors (including cars), achieving lower hydrogen and electrolyser costs through scale.
  - Drive mass deployment, incentivise local OEM manufacturing to cut costs.
- **EU:** Clearer policies for hydrogen in heavy transport (e.g., binding decarbonisation targets).
  - Set clear sectoral targets for hydrogen.
- **Germany:** National hydrogen pipeline plan with staged construction, providing visibility and confidence.
  - Publish an integrated, phased hydrogen infrastructure roadmap.
- **Spain:** Grants capacity for blending and aims to connect to Germany via pipelines.
  - Enable early blending permissions and explore cross-border hydrogen trade.
- **Norway:** National hydrogen flight network (with ZeroAvia) connecting airports.
  - Develop a domestic aviation hydrogen strategy with defined routes.
- **Netherlands:** Airport hydrogen infrastructure pilots and collaborative data-sharing; Rotterdam as a port hub.
  - Foster non-competitive collaboration, invest in airport-and-port hydrogen infrastructure.

Future Scenarios

When asked about potential future scenarios for hydrogen development and the UK hydrogen network, stakeholders emphasised that outcomes will depend heavily on geopolitics. They noted that the future could be highly positive or highly negative, depending on government decisions made now:

Positive scenario:
Global climate pledges and international alignment accelerate hydrogen adoption, with EU-level decisions playing a pivotal role. In the UK, more projects reach FID under HAR, technology and equipment (e.g., electrolysers) become cheaper, Project Union gets the go-ahead, and hydrogen production scales up. Political backing helps break the chicken-and-egg cycle, making hydrogen cheaper in the long term.

Negative scenario:
A new government with weaker Net Zero ambitions (or no support for hydrogen) slows progress. Fragmentation within the EU creates uncertainty: some regions lead (e.g., Northern Europe) while others lag, affecting confidence and planning. A pure H_2 pipeline network is delayed to a 40–50-year horizon, and near-term focus remains on distributed, local production and use tied to cheap electricity and specific industrial processes.

One stakeholder referenced NESO's scenarios, noting no preference amongst them, only a desire for a strategy that makes sense and uses hydrogen wisely.

[redacted]

Conclusions & Recommendations

Conclusions

- **Uncertainty** is hindering hydrogen development, turning potential enablers into barriers. Addressing uncertainty around policy, funding, demand and supply, and grid connection is critical to provide stakeholders with the clear signal they need to **boost their investment confidence**.

- Currently, stakeholders are developing **projects at significant risk**. They are advancing through active engagement across the value chain and funding initiatives that could collapse if political priorities shift away from Net Zero, leaving hydrogen projects unsupported. Their financial resources, time, and commitment are deeply invested in projects that remain vulnerable to market uncertainty.

- The **lack of a national hydrogen pipeline infrastructure** complicates operations for both producers and users. They are forced to plan based on limited local infrastructure. When nearby options are unavailable, relying on local supply or consumption can significantly increase costs due to storage and transportation requirements. While a national network may not eliminate costs (since connection fees and infrastructure adaptation would still apply), it would help **break the chicken-and-egg cycle** that currently constrains production and demand.

- A key factor fuelling uncertainty and eroding trust in the hydrogen network is the perceived lack of communication. Stakeholders emphasise the need for a sufficiently detailed yet high-level **long-term plan** that includes timelines, locations, and processes for infrastructure rollout, enabling them to align budgeting and operational planning accordingly. In parallel, initiatives are needed to connect production with demand and to raise public awareness of hydrogen, building trust, acceptance, and support for its development.
  Even the fact that they raised some ideas or policies that are already in place reflects the need and relevance of sharing more information with them.

Recommendations

To build trust among stakeholders and support the development of a successful national hydrogen network, it is essential to address key uncertainties:

Policies and legislation:
- Long-term planning tied to Net Zero targets and independent of political cycles
- Clear policy around hydrogen blending and carbon-tax
- Standardisation that is driven by off-takers needs and enables alignment

Funding:
- Reliable and regular funding streams
- Support to make equipment more accessible

Off-taker demand:
Active promotion of hydrogen across:
- Industry: adopting a balanced approach that recognises its role where electrification is impractical
- Stakeholders: developing live, shared platforms that connect production and demand
- General public: increasing awareness and reducing perceived risks
- Other sectors: e.g., banking, to help reduce insurance premiums and loan fees

Planning and communication:
- Development and communication of a sufficiently detailed yet high-level long-term plan that includes timelines, locations, and processes for the national hydrogen infrastructure rollout.

This recommendation is the most feasible in the near term and has the potential to deliver meaningful impact.

Annexes

Technical factors affecting efficient operation

TECHNICAL FACTORS		UNDER-ADDRESSED BY THE INDUSTRY
1. Electrolyser operational flexibility and efficiency	• Ability to ramp up/down on demand without degrading electrolyser efficiency. • Operational flexibility implications for equipment lifetime, stack reliability, uptime, and OEM warranties.	Impacts of flexible cycling on asset life and warranties; ensuring efficiency under flexible dispatch.
2. Electricity–hydrogen system integration and curtailment	• Integrating electrolysis to absorb low-price or excess power (avoiding curtailment) and store energy as hydrogen for reuse.	Practical mechanisms to utilize curtailed power, and investment to relieve constraints.
3. Power quality, grid connection, and market signals	• Grid connection challenges; need for balancing signals that reward short-notice hydrogen power generation. • Long-duration energy storage (hydrogen) identified as a gap in current system design.	Compensation frameworks for short-notice dispatch; enabling hydrogen as long-duration storage within system planning.
4. Infrastructure for hydrogen transport, storage, and logistics	• Pipelines lacking; reliance on tube trailers and onsite storage increases costs and narrows viable markets. • Liquefaction energy requirements and the challenge of running projects at scale.	Network build-out, storage access, and logistics standards to reduce delivered hydrogen costs.
5. Asset performance and cost base	• Total Cost of Ownership (TCO) of electrolysers, CapEx, uptime/reliability, and the value of off-site H_2.	Transparent TCO benchmarking under flexible operations and clear durability metrics.
6. System planning, forecasting, and coordination	• Need for improved demand/supply forecasting and communication with variable providers of load (e.g., hydrogen).	Integrated planning and information flows across power and hydrogen sectors.

LQ1. In your opinion, what are the key technical or commercial factors that could affect the efficient operation of an integrated hydrogen-electricity system, and which do you feel are currently under-addressed by the energy industry? (Total valid responses: 11 who provided an answer)

Commercial factors affecting efficient operation

COMMERCIAL FACTORS		UNDER-ADDRESSED BY INDUSTRY
1. Electricity cost exposure and contract structure	• Electricity cost is a primary driver of hydrogen production economics. • PPAs can comprise up to ~70% of operational costs; getting this cost right is crucial and ultimately affects end-consumer hydrogen prices.	Fit-for-purpose PPAs and market products for flexible electrolysis, including hedging and price-responsive operation.
2. Market frameworks and compensation	• Need for a commercial framework that compensates hydrogen power generation for short-notice requirements and avoids penalizing infrequent use.	Market products for capacity firming, balancing, and long-duration storage via hydrogen
3. Regulation, standards, and policy support	• Lack of regulation, evolving standards (storage, transport), organisation of the electricity grid, available land, and public awareness. • Timely government support is crucial to deployment.	Clear, mature standards; streamlined grid and land processes; targeted public engagement and predictable policy support.
4. Practical market entry and transition pathway	• Need a practical market entry strategy for green hydrogen: start with premium segments viable at small scale to create demand and unlock investment. • Recognition of a glidepath from grey to green hydrogen; insisting on green only, in lockstep with new demand, can create artificial commercial barriers. • Strategy should match hydrogen vs. electricity to sector characteristics, not force hydrogen into "hard-to-abate" sectors first.	Transitional policies enabling early markets, realistic demand build-up, and sector prioritization.
5. Network-enabled resilience and market expansion	A national hydrogen network can: • Provide resilience (re-matching producers and offtakers if one becomes unavailable), reducing WACC and strike prices (subsidy needs). • Enable balancing via access to storage and optimized dispatch at low power price periods. • Decouple supply and demand (beyond bilateral, co-located models), reducing the need for joint final investment decisions and complexity. • Deliver location and power system benefits (e.g., relocating electrolysis to Scotland to reduce constraints, grid GHG intensity, and reliance on imports; support industrial clusters and storage).	Development of backbone network (e.g., export routes), and recognition of system-wide benefits in planning and subsidy design.

LQ1. In your opinion, what are the key technical or commercial factors that could affect the efficient operation of an integrated hydrogen-electricity system, and which do you feel are currently under-addressed by the energy industry? (Total valid responses: 11 who provided an answer)

Factors that would drive operation

Stakeholders highlighted that, out of the factors mentioned in the previous question, these would be the top drivers of operational choices:

1. Infrastructure & supply reliability
2. Electricity market & grid conditions
3. Electrolyser flexibility/reliability & warranties
4. Standards, and commercial structures (PPA costs, blending/offtake security).

Important examples of these factors include:

- Need for LH_2-ready infrastructure; reliance on tube trailers undermines perceived reliability.
- Variable tariffs, curtailment, and private-wire setups materially affect dispatch and siting.
- OEM warranties/specs for flexible operation and electrolyser reliability are critical decision inputs.
- Standards are foundational: operators need clear "rules of engagement."
- PPA cost reduction and hydrogen blending can stabilise pricing and broaden offtake.
- For vehicle operators, these factors shift economic barriers rather than operating strategy.

LQ2. Which of the factors you mentioned would most influence how you choose to operate your facility? (Total valid responses: 11 who provided an answer)

Survey questionnaire

Survey questionnaire

Energy Systems

FOGSI Survey Questionnaire draft

Introduction

Thank you for agreeing to complete this short online survey, conducted by **Energy Systems Catapult** on behalf of **National Gas**, as part of the **FOGSI project**.

We're gathering insights from hydrogen producers and users in hard-to-decarbonise sectors to better understand the industry's technical, operational, and infrastructure requirements. Your input will help shape the development of a national hydrogen transmission and distribution network that is resilient, future-ready, and designed around **your needs.**

By participating, you'll contribute to shaping future policy and planning, and you will gain early access to key findings from the project.

The survey takes approximately 15 minutes to complete. All responses will be strictly confidential and data from this research will be reported only in the aggregate. Your information will be coded and will remain confidential. If you have any questions, please contact us at pamela.espinozavigo@es.catapult.org.uk

About FOGSI

Future Operability of Gas for System Integration (FOGSI) is developing an integrated modelling framework to simulate future Great Britain energy system scenarios, with a focus on the interaction between gas and power networks. It will realistically model power-to-gas and storage operator behaviour and demonstrate these models as real-time digital twins.

About Energy Systems Catapult

Energy Systems Catapult is an independent research and technology organisation established by Innovate UK and ultimately funded by the UK Government's Department for Science, Innovation and Technology (DSIT).

This research is being conducted under the Market Research Society Code of Conduct, which ensures that all responses are handled confidentially and ethically. To verify our credentials, search for "Energy Systems Catapult" at: www.mrs.org.uk/researchbuyersguide.

Questions for All:

1. What is your organisation's primary role within the hydrogen value chain?
   (single choice)
   a. Production
   b. Distribution
   c. Storage
   d. Use

2. Where are you located?
   (single choice)
   a. North East
   b. North West
   c. Yorkshire and the Humber
   d. East Midlands
   e. West Midlands
   f. East of England
   g. London
   h. South East
   i. South West
   j. Scotland
   k. Wales
   l. Northern Ireland

3. When do you expect your project to deploy?
   (single choice)
   a. Before 2030
   b. Between 2030 and 2034
   c. Between 2035 and 2039
   d. Between 2040 and 2049
   e. 2050 or later

4. How confident are you in this estimation?
   (single choice)
   a. Completely confident
   b. Very confident
   c. Moderately confident
   d. Slightly confident
   e. Not at all confident

5. Are you considering any government support schemes for hydrogen production or infrastructure? If so, which one(s)?
   (multiple choice)
   a. Hydrogen Production Business Model
   b. Hydrogen Transport Business Model
   c. Hydrogen Storage Business Model
   d. Hydrogen Allocation Rounds
   e. CCUS funding
   f. Other (please specify)
   g. I'm not sure
   h. I am not considering a government support scheme

6. What are the main risks that could delay your project? Please rank the following from highest to lowest risk.
   a. Financing
   b. Permitting
   c. Infrastructure access
   d. Market uncertainty
   e. Technical challenges
   f. Other (please specify)

Questions for Producers

7. What hydrogen production method will you use?
   (single choice)
   a. Electrolytic
      I. Alkaline Electrolysis
      II. Proton Exchange Membrane Electrolysis
      III. Solid Oxide Electrolysis Cells
      IV. Anion Exchange Membrane Electrolysis
      V. Electrolytic, not sure about the specific type
   b. Thermal/Fossil Based
      I. Steam Methane Reforming
      II. Autothermal Reforming
      III. Biomass Gasification/Reforming
      IV. Steam Methane Reforming with CCS
      V. Autothermal Reforming with CCS
      VI. Biomass Gasification/Reforming with CCS
      VII. Thermal/Fossil based with CCS, not sure about the specific type
      VIII. Thermal/Fossil based without CCS, not sure about the specific type
   c. Other (Please Specify)

8. What's your expected production capacity per site in the first year (in tonnes H_2/year)?
   (numeric input)

Survey questionnaire

9. Do you expect to scale production in the future?
   (single choice)
   a. Yes
   b. No
   c. Unsure

   IF Q9. a. ASK:

   9a. What is the maximum scale you expect to achieve? (in tonnes H_2/year)
   (numeric input)

   9b. How soon after launch do you expect to achieve this maximum scale? (in years)
   (numeric input)

10. What level of certainty do you have in these production estimates?
    (single choice)
    a. High certainty (quantitative projections with strong confidence)
    b. Medium certainty (quantitative projections with moderate confidence)
    c. Low certainty (estimates only)

11. Where will you source electricity from? Select all that apply
    (multiple choice)
    a. Grid supply
    b. Wind
    c. Solar
    d. Other renewable source
    e. Other – please specify

11a. From the ones you selected, which will be your main electricity source? *(single choice)*

   a. Grid supply
   b. Wind
   c. Solar
   d. Other renewable source
   e. Other – please specify

12. Do you expect to connect to a carbon capture and storage network?
    (single choice)
    a. Yes
    b. No
    c. Unsure/Planning

13. Do you expect to connect to a hydrogen network or operate locally with a limited number of off-takers?
    (single choice)
    a. Connect and supply only to a hydrogen network
    b. Connect and supply mostly to a hydrogen network
    c. Connect and supply to both: hydrogen network and local off-takers
    d. Connect to a hydrogen network but supply mostly to local off-takers
    e. Supply only to local off-takers
    f. Other (please specify)

   IF Q13. b-d. ASK:
   13a. What percentage of your hydrogen production do you expect to supply to the hydrogen network?
   (numeric input)

   IF Q13. a-d. ASK:

   13b. What technical requirements do you have for your connection? Please specify quantities and units if applicable
   (open ended)

   a. Pressure restrictions and requirements: ____
   b. Flow requirements and maximum injection/withdrawal rates: ____
   c. Required hydrogen purity (min./max. % and contaminants): ____
   d. Specific treatment or conditioning needs: ____
   e. Connection specifications to the national network: ____
   f. Others (please specify)

14. Which of the following production patterns best describes your operating model? Please select one and provide details if applicable
    (single choice)
    a. Producing continuously: 24 hours per day, 7 days per week
    b. Producing consistently on certain days and times (please specify number of days per week and hours of production)
    c. Producing intermittently (please specify approximate frequency)

15. How frequently do you anticipate operating below full load?
    (single choice)
    a. Rarely (<5% of operating hours)
    b. Occasionally (5-10% of operating hours)
    c. Regularly (10-50% of operating hours)
    d. Very often (>50% of operating hours)

16. What operating load range do you expect your hydrogen production system to support (minimum % load to maximum % load)?
    (numeric input)

17. What is the expected maximum ramp-up rate (% of rated capacity per second/minute)?
    (numeric input)

18. What is the expected maximum ramp-down rate (% of rated capacity per second/minute)?
    (numeric input)

19. Do you plan for the asset to provide short-term electricity grid balancing (demand response services)?
    (single choice)
    a. Yes, within seconds
    b. Yes, within minutes
    c. No

20. What is the projected start-up time from cold/offline state to full load? (in minutes)
    (numeric input)

21. Do you have minimum up/down times or required minimum run durations after start-up?
    (single choice)
    a. Yes (please specify)
    b. No

22. Do you plan to adjust hydrogen production in response to:
    (multiple choice)
    a. Electricity price signals
    b. Renewable generation availability
    c. Industrial demand fluctuations
    d. Grid balancing markets
    e. Other (please specify)

23. What are the expected demand cycles or variations in hydrogen production?
    (single choice)
    a. Seasonal
    b. Monthly
    c. Weekly
    d. Daily
    e. None

Survey questionnaire

CATAPULT Energy Systems

24. What additional factors are expected to influence fluctuations in your hydrogen supply or operation?
(open ended)

25. How important is operational flexibility in the design of your project?
(single choice)
    a. Not important
    b. Moderately important
    c. Very important
    d. Critical

26. Will you include on-site hydrogen storage to manage demand fluctuations?
(single choice)
    a. Yes, large-scale storage (buffer hours/days)
    b. Yes, small-scale storage (buffer minutes/hours)
    c. No

IF Q26, a-b, ASK:

26a. What is the planned storage capacity (in tonnes H_2)?
(numeric input)

26b. What is the function of your on-site hydrogen storage? Select all that apply
(multiple choice)
    a. Buffering production and demand – to manage fluctuations between hydrogen generation and usage
    b. Backup supply – to ensure continuity during production downtime or supply interruptions
    c. Load management – to optimise energy use and reduce peak electricity costs
    d. Grid balancing / ancillary services – to support grid stability or participate in energy markets
    e. Safety and compliance – to meet regulatory or operational safety requirements
    f. Transport scheduling – to align with delivery logistics or vehicle refuelling schedules
    g. Seasonal or long-term storage – to store hydrogen for use over extended periods
    h. Other (please specify)

Questions for Users

7. What processes do you plan to use hydrogen for? Select all that apply and specify if applicable
(multiple choice)
    a. Chemical process (e.g., ammonia, methanol, refining)
    b. Industrial fuel switching (e.g., steel, glass, ceramics)
    c. Power generation (fuel cells or turbines)
    d. Other (please specify)

8. What is the planned hydrogen demand (in tonnes H_2/year)?
(numeric input)

9. What level of certainty do you have?
(single choice)
    a. High certainty – quantitative projections with strong confidence
    b. Medium certainty – quantitative projections with moderate confidence
    c. Low certainty – estimates only / indicative

10. Do you expect to connect to a hydrogen network?
(single choice)
    a. Yes
    b. No

IF Q10, a, ASK:
10a. What proportion of your hydrogen demand do you expect to draw from the hydrogen network (vs. storage or other sources)? Please provide an approximate percentage
(numeric input)

10b. How do you expect to use the hydrogen network? Please select the option that best describes your expected usage pattern
(single choice)
    a. As a consistent, daily source of hydrogen
    b. To top up hydrogen supply on a weekly basis
    c. To top up monthly
    d. As an infrequent source to buffer supply during peak demand

10c. What technical requirements do you have for your connection? Please specify quantities and units if applicable
(open ended)
    a. Pressure restrictions and requirements: ____
    b. Flow requirements and maximum injection/withdrawal rates: ____
    c. Required hydrogen purity (min. % and contaminants): ____
    d. Specific treatment or conditioning needs: ____
    e. Connection specifications to the national network: ____
    f. Others (please specify)

11. What is the expected load profile?
(single choice)
    a. Constant/baseload demand
    b. Daily fluctuations
    c. Seasonal fluctuations
    d. Intermittent/peak-only demand

IF Q11, b-d, ASK:

11a. Within your load profile, what is the maximum (peak) demand expected? (in tonnes H_2/year)
(numeric input)

11b. And what is the minimum demand expected? (in tonnes H_2/year)
(numeric input)

12. What is the minimum operating load (as % of maximum hydrogen demand)?
(numeric input)

13. What is the maximum ramp-up rate needed (% of demand per minute/hour)?
(numeric input)

14. What is the maximum ramp-down rate needed (% of demand per minute/hour)?
(numeric input)

15. Do you plan to integrate on-site hydrogen storage to manage fluctuations in supply?
(single choice)

Survey questionnaire

a. Yes, large-scale (hours/days buffer)
b. Yes, small-scale (minutes/hours buffer)
c. No

IF Q15, a-b, ASK:

15a. What is the expected storage capacity (in tonnes H_2)?
(numeric input)

16. How quickly do you expect the hydrogen supply to respond to changes in demand at your site(s)? Please specify if minutes, hours or days
(numeric input)

17. Which of the following external factors would influence or trigger adjustments in your expected hydrogen demand? Select all that apply
(multiple choice)

a. Electricity price signals
b. Renewable generation availability
c. Industrial process scheduling
d. Grid or market incentives
e. Others (please specify)

18. How would you describe the overall flexibility of your hydrogen demand in relation to network needs?
(single choice)

a. Fully internally driven — cannot adjust to external signals
b. Partially flexible — can adjust within limited operational windows
c. Fully flexible — can adjust on request to support network/system needs

19. How critical is uninterrupted hydrogen supply to your operations?
(single choice)

a. Non-critical — operations can stop or delay without major impact
b. Moderately critical — short interruptions are manageable (up to a few hours)
c. Highly critical — continuous supply is required
d. Mission-critical — interruption would cause major operational issues

20. Do you have alternative fuel or energy sources available if hydrogen supply is interrupted?
(single choice)

a. Yes (please specify)
b. No

21. Are there any additional operational constraints we should be aware of?
(open ended)

IF Q7, c (Power generation (fuel cells or turbines)), ASK:

22. What ancillary services can your hydrogen-fired power generation provide to the electricity grid? Select all that apply
(multiple choice)

a. Frequency regulation (automatic up/down response)
b. Voltage support / reactive power
c. Spinning reserve / reserve capacity
d. Black-start capability
e. Capacity firming or balancing renewable output
f. Other (please specify)

23. Under what market conditions would your hydrogen consumption for power generation be triggered or adjusted? Select all that apply
(multiple choice)

a. High electricity market prices
b. Low electricity market prices (arbitrage)
c. Renewable generation shortfall (wind/solar)
d. Peak grid demand periods
e. Contracted ancillary service obligations
f. Emergency / backup situations
g. Other (please specify)

Additional final questions for all

Before finishing, please share your thoughts on these two last questions:

1. In your opinion, what are the key technical or commercial factors that could affect the efficient operation of an integrated hydrogen-electricity system, and which do you feel are currently under-addressed by the energy industry?
(open ended)

2. Which of the factors you mentioned would most influence how you choose to operate your facility?
(open ended)

Closure

Thank you for completing the survey.
Your insights are invaluable in helping shape the future of hydrogen infrastructure in Great Britain.

As part of this project, we're also conducting in-depth 30-min interviews with stakeholders like you to explore technical and operational needs in more detail. Would you be happy to be contacted for an interview, or for any future research related to hydrogen and energy systems?

- Yes, I'm happy to be contacted but only for interviews for this project
- Yes, I'm happy to be contacted but only for future research
- Yes, I'm happy to be contacted for both
- No, I'd prefer not to be contacted

If you select "Yes," we'll only contact you for this and/or other relevant research opportunities. Your details will be stored securely, not shared outside the project team, and you can request deletion at any time. We will only retain your contact information until interviews are done, by January 2026. Additionally, as promised, you'll receive early access to key findings from the research.

Interviews discussion guide

Interviews discussion guide

FOGSI IN-DEPTH INTERVIEWS
DISCUSSION GUIDE

This discussion guide has been designed as a flexible question pack to support conversations around current infrastructure, enabling conditions, challenges, and future strategies for hydrogen network development.

Interviews will be conducted as open discussions, beginning with broad questions to encourage free-flowing dialogue. Key questions are in ***bold****. More specific questions will be introduced where relevant, based on the direction of the conversation.*

Introduction:
Thank you for joining me today. We really appreciate your insights and experience in this area, they're invaluable to shaping our work. This session should take about 30 min., and if at any point you'd like to pause or skip a question, that's absolutely fine.

As a reminder, the Future Operability of Gas for System Integration (FOGSI) project is looking to understand the industry's technical, operational, and infrastructure requirements. Your input will help shape the development of a national hydrogen transmission and distribution network that is resilient, future-ready, and designed around your needs.

All responses will be strictly confidential and anonymised. Anonymous data will only be shared with consortium members involved in modelling the hydrogen network: National Gas Transmission (NGT), TNEI, and the University of Edinburgh. We'll aggregate and anonymise all responses before sharing any results. Findings will be presented as overall trends (not individual responses) so nothing will point back to a specific project or company. This ensures that commercially sensitive information stays protected.

Before we start, we'd like to record the conversation to help ensure accuracy, but the recording will only be used for analysis and remain confidential. Is that okay with you?

1. **Conversation starter**
   - **Q1.** Were there any topics or technical aspects you feel were underexplored in the survey? Anything you'd like to expand on or feel is particularly important to highlight?

2. **Infrastructure and technical enablers**
   - **Q2. From your perspective, what are the key enabling conditions or factors that support hydrogen project development in the UK (particularly those related to infrastructure)?**
   - **Q3. How important is access to hydrogen infrastructure for the success of your current projects and future plans?**
     - **And which specific infrastructure requirements are the most critical for enabling your hydrogen operations?**
   - **Q4.** Are there any current or anticipated gaps or limitations in existing hydrogen infrastructure that concern you?
   - **Q5. How important is hydrogen network standardisation to your operations?**
     - **And which aspects do you believe most need standardisation (e.g., purity, pressure, connection protocols)?**
   - **Q6.** What role, if any, could digital tools or data-sharing platforms play in supporting hydrogen infrastructure planning or operations?
   - **Q7. Briefly**, what other assumptions (beyond those discussed already) underpin your hydrogen project and your production/demand estimates?
     - And how confident are you on these assumptions?

3. **Strategic planning and industry outlook**
   - **Q8. What would help make connecting to a hydrogen network more viable or feel like the right step for your organisation?**
   - **Q9. What factors would influence your decision to connect to a national hydrogen network versus producing or consuming hydrogen locally (e.g., through a GDN or direct supply to an industrial cluster)?**
   - **Q10.** Have you had any previous interactions with other parts of the hydrogen value chain to help ensure your plans align well with the wider system?
   - **Q11.** What signals or commitments from government or industry would give you more confidence to invest or scale up hydrogen activities? (besides blending decisions)
   - **Q12.** Are there international examples or models you think the UK could learn from?
   - **Q13. What are the biggest uncertainties or risks you're currently navigating in your hydrogen plans?**
   - **Q14.** Are there any policy changes or market mechanisms that would significantly influence or shift your approach (other than the signals/commitments you have already mentioned)?
   - **Q15.** What forms of coordination or information-sharing would help you better plan or operate your hydrogen activities?
   - **Q16.** Are there technical or commercial aspects that you feel are under-addressed by the industry?
   - **Q17.** What future scenarios (e.g., demand growth, technological breakthroughs, policy shifts) would most impact your hydrogen strategy?

Thank you for sharing your time and insights today. Your input is extremely valuable and will help us better understand the challenges and opportunities in this area. If you have any additional thoughts after the interview, please feel free to reach out. We'll keep you updated on the next steps and share the findings as promised, so you can see how your feedback has contributed to the project.

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Thank you.

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