Control Rooms of the Future – Energy System Integrations in practice

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Abstract

This paper outlines potential future roles for control rooms in a more integrated energy system. In the context of energy systems integration, it looks at opportunities for improving operation in terms of cost, carbon emissions and security of supply through coordination between gas and electricity distribution networks. Based on a case study of NE England Distribution Network Operators (DNOs), it examines regulatory and institutional issues, infrastructure capacities and control room practices. As an exercise in collaborative interdisciplinary research, it was conducted in partnership between Durham and Newcastle universities and two DNOs, and includes ethnographic, empirical and theoretical methods.

Introduction

The primary goal of the National Centre for Energy Systems Integration is to understand multiple dimensions of energy supply and demand by bringing together existing and new models that integrate different energy 'vectors'. Alongside the technical modelling questions, a host of questions arise around institutional and regulatory issues – all of the social and political infrastructure that enables technologies to function in the world. The broad question is how the energy system could be operated as a 'whole system', and what design steps could be taken that would facilitate whole-systems operations. Beyond theoretical questions about how different technologies might be operated more effectively by coordinating different parts of energy system infrastructures, there are practical questions about how different operations could really work together on an everyday basis. Are there benefits to be gained through joint operation of energy vectors, and where would they lie? And are do these entail risks, and are these acceptable?

In the realm of energy distribution, there are big questions about the role of distribution network operators (DNOs) in Gas and Electricity, and how their role is transforming them into Distribution System Operators (DSOs)[1]. There are big questions about where investments should be directed to move the systems into a new, decentralised and integrated energy system. And there are practical, but equally crucial questions about how gas and electricity distribution are operated and controlled. What will happen to Control as the grids adjust to new patterns of energy generation and demand? Already, the gas and electricity grids are integrated to some extent at various levels. Gas distribution uses electric pumps and feeds gas-fired power stations, for example (although larger CCGT are fed through the transmission system). Gas networks are increasingly being fed from small bio-gas plants at various sites. As these grow, and as new gas-blends emerge, what implications will these have for the gas-electricity nexus?

[1] For the sake of simplicity, we will refer to these as DNOs throughout the paper.
Add ref on DNO/DSO

This paper addresses the roles of distribution control rooms, how they manage grids and systems on an everyday basis, and what factors might be significant in bringing about integration. It is based on a scenario for energy futures that responds to the changing balance of renewable and fossil-based energy sources. The UK national electricity grid, as most national grids in the Global North, were designed in an era of large fossil-fuel powered generation plant, where electricity generation could be dispatched centrally to meet demand at any moment (demand-led). Electricity generated from renewable sources, on the other hand, usually depends on the availability of resources, that is, power can only be generated when the resource is available – at present, largely when it is windy or sunny (generation-led).

At present, where there is a surplus of supply over demand, renewable may be constrained, ie switched off, or 'curtailed'. As the penetration of renewables increases this is likely to happen more often unless there is mitigation. Renewable resources may also not be available when people need them, so the grand challenge of a renewable electricity grid is to find ways to store the energy until it is needed. Electricity itself cannot be stored practicably, but electrical energy can be converted into other forms that can be re-converted into electricity later. Large scale energy storage is currently only provided on the UK electricity system by pump-storage hydro-electric plants (around 2.8GW installed capacity), and in some smaller scale batteries (currently around 700MW installed capacity).

Other options include using available electricity from renewable sources to power a hydrolyser that can isolate Hydrogen (either from methane or water), or using ammonia as a storage medium. Large scale hydrolysers are emerging onto the market, and could be used to generate large quantities of hydrogen that can be stored and later burned cleanly to generate electricity.

But where could potentially large quantities of Hydrogen be stored until needed? Hydrogen could be stored in tanks to supply generators, or alternatively, coordination between electricity and gas distribution networks could be put to use. Hydrogen could be stored in the variable-pressure pipes of the gas system and blended into the gas supply. Making such a direct connection between the gas and electricity networks would require some coordination, and this paper reports on a preliminary exploration of what those requirements might be, how they might affect the operation of energy distribution, and what regulatory, institutional or governance issues might arise.

Why control rooms?

Until recently, most power generation and gas production was connected to the national transmission systems and most demand was connected to the local distribution networks. As a result, transmission aand distribution of gas and electricity are carried out hierarchically, with national transmission systems feeding regional distribution systems. With increasing levels of distributed generation, from both renewables and fossil based generation, there are now times when some electricity distribution networks export to the transmission system[2].

At each level, there are control rooms that operate the system, manage faults and upgrades, monitor safety and ensure the smooth running of the systems. At the

[2] Distributed gas sources, such as biogas, remain at a small scale relative to overall demand, so local gas networks never export to the transmission system.

transmission level, this includes active management of both power generation and network operation. As changes to the grids lead to increased requirements for flexibility and decentralisation, Active Network Management (ANM) is seen as an essential ingredient in the effective use of existing infrastructural assets that will also impact the distribution level. Distribution network operators are therefore facing potentially profound changes from the previous passive management mode. Some ANM can be carried out remotely, and some may be possible to implement automatically in relation to particular assets. However, our visits to DNO control rooms revealed just how far the distribution networks are from comprehensive automation or even comprehensive remote operation. With decades' worth of infrastructural history embedded in the networks' ranges of assets, the upgrading of all equipment even to be remotely controlled remains a long way off. This in itself would require significant investment, on a scale not recently experienced in the UK. Hence, active engagement through network control rooms remains a reality that will need to be addressed.

Although control rooms themselves are conceptually relatively simple, they are complex arenas of action. There are diverse definitions of control rooms; Roe and Schulman, for example, helpfully define the aim of a control room as, "managing a critical service reliably and safely, in real time, given their system definitions and the specifics of their governing reliability standards" (2018). In brief, the control room is the point where diverse distributed activities (at a distance[3]) are subject to centralised regulation and oversight, so that the physical space of a control room and the people working within it can be seen as just one aspect of control room operations. The control room also incorporates the physical equipment within the space, and the links (cables, telecoms) to the equipment being controlled, the tools and systems for analysing data and recommending actions, and the documentation specifying the framework of procedures, rules, guidelines and protocols that govern the network. When we refer to 'Control Rooms', therefore, we are using shorthand to refer both to the room where the control engineers sit, with all its internal equipments, and also the broader control operation linked to 'backroom' operations, on-site assets and activities.

Distribution control rooms are heavily regulated (as we outline below), with a primary overriding concern with safety followed by system-management, and indirectly with market operations. In both gas and electricity distribution control rooms, commercial concerns are secondary, with safe and reliable operation prioritised. Control engineers and shift managers describe their role as moving energy resources from A to B, ie from Transmission to supply. They see commercial concerns are the remit of other parts of their organisations. Almost every aspect of their everyday operations are coded and regulated. Engineers learn how to follow scripts for giving and confirming information and instructions. This is particularly tightly codified in the electricity control room, but communications are also formal and recorded in the gas control room. At the same time, control room operations also rely on a degree of flexibility and informality which gives room for engineers to use their skill and knowledge in the face of new situations.

Decades of research on organisations shows that working environments are not perfectly uniform, but that working practices adapt over time to the people who are working, the

[3] See Latour 1988.

changing strategic and managerial goals of the organisation, and the specific contextual factors in the geographical area being controlled. No two regions of the networks are identical, for example, so different regions adopt slightly different working practices. Different energy vectors also have different requirements, so that gas and electricity organisations also work in different ways.

If an ambition in the networks is to develop infrastructure that links two parts of the system in new ways, then it is important to take seriously the similarities and differences in working practices in the two parts. In this case, we are interested in the different practices in control rooms of the gas and electricity distribution networks, where coordination between renewable hydrogen production and use would be carried out. Relevant questions include:

- How well do the tasks and roles in the different control rooms correspond?
- Are there different levels of urgency or extent of active intervention needed?
- Are all the relevant actions taken at the Distribution level?
- At what scale of production does gas-for-storage become significant on either side?
- What regulatory, market or institutional factors might affect co-operation?
- And how could control room practices be adapted to enable new possibilities for energy storage?

The case study

Northern Gas Networks (NGN) is the local gas distribution network for Yorkshire and North-East England. It is embarking on this journey towards ANM and integrated energy operation at their InTEGrel site in Gateshead in the NE of England. This Integrated Transport Electricity and Gas Research Laboratory encompasses transport, electricity and gas on one site, and is the product of partnership between Northern Powergrid (NPG, the broadly equivalent electricity distribution network), Newcastle University and the EPSRC Centre for Energy Systems Integration (CESI). The lab offers an experimental site at which to test the potential for gas and electricity integration where scenarios can be tested and evaluated.

While storage and an electrolyser plant are planned for the InTEGrel site, they were not yet commissioned in time for this project. Data from the site and from the local area networks was made available by NGN and NPG for the purposes of this case study. The study encompassed a regulatory review, empirical observations of gas and electricity distribution control rooms including interviews with key staff, and a modelling exercise based on future scenarios for electricity-gas integration via hydrogen. Three control room shifts were observed in each distribution system (gas and electricity), complemented by unstructured interviewing of key professionals. Industry expertise provided oversight of regulatory issues, and a modelling exercise was conducted using a techno-economic-environmental evaluation framework to analyse three potential scenarios. This research therefore represents a cross-disciplinary collaboration and represents a pilot study for further research on the role of DNO/DSO integrated energy system operation in the UK.

It is important to note that there is not currently any significant Active Network Management in the NE region of England (encompassing Yorkshire and Humber and the NE region). This reflects the history of the region. The conventional energy infrastructure was designed to serve what was once a significant amount of heavy industry. Much of this industry having now gone, or been scaled down, there is generally an overcapacity of energy distribution infrastructure. Much of the electrical network, for example, is over-

rated, or has under-used assets. Large solar installations are less popular here than in the South of England, which receives greater insolation. However, as new, large scale offshore wind energy plant is being installed (particularly off the coast, from Hull and the NE), the geography of this infrastructure is changing. Much of the infrastructure is ageing, and as assets are decommissioned, they are likely to be replaced with lower capacity infrastructure. Increasing demands from electric vehicles, electric-powered heating and local generation are also likely to bring new pressures to the network. Hence, although curtailment of renewable energy is not currently an issue in this region, it is expected to become increasingly important, and it is already practiced in other regions (such as the SW), where active network management is already in use.

Regulatory overview

The control rooms of electricity and gas distribution networks are integrated parts of the distribution business, which are subject to a range of sector specific legislation and regulation as well as general law. At present, UK law operates in the context of European law, which comprises regulations (which are directly applicable) and directives (which are implemented through national regulation). After the UK leaves the EU, most relevant regulations will be transferred directly into UK law, so will continue to have force. All companies are subject to general law and regulations, which includes (as some particularly relevant examples) health and safety regulations, employment law, environmental regulations, planning law and competition law.

Under the Gas and Electricity Acts, the functions of gas and electricity distribution are designated as licenced activities. This means that nobody can carry out public electricity distribution without first being granted a licence. There are exemptions from this requirement (e.g. in relation to private networks). Electricity and gas distribution companies are required to adhere to the conditions of their licence, which fulfils a number of functions.

- Significantly, the licence contains the conditions of the network price control, which determines the revenues the company can recover from its customers.[4] These price controls are far more than simple price caps. They provide a complex incentive framework to encourage network companies to deliver certain outcomes as efficiently as possible.
- The licence also requires the company to adhere to the relevant network codes, of which there are a number.
- In addition, network companies are required to adhere to a range of standards, which include standards that cover technical issues, service quality and quality of supply.
- There will be a range of other licence conditions. For example, network companies will be subject to a number of social and environmental requirements.

Distribution licences are administered and enforced by Ofgem. Ofgem can propose changes to licence conditions, which come into effect after consultation unless appealed[5] by an affected party. This includes changes to price controls, which take place at periodic reviews

[4] It should be remembered that the customers of the distribution company are not the end consumers, but licenced gas and electricity supply companies (retailers) and licenced power generators.

[5] Appeal routes include to the CMA (on the substance of the licence change), or to the courts as a judicial review (on process and rationality).

once every 5-8 years. Breaches of licence conditions are subject to enforcement action by Ofgem, which has a range of sanctions available to it, including fines.

Network codes cover the detailed rules that govern the relationship between distribution networks and their users (both generation and demand). In electricity, there are separate codes for the technical aspects (the distribution code) and the commercial aspects (the distribution connection and use of system code). In gas, these elements are unified in a single code.

Codes are intended to be largely self-governed by the industry and are administered by various code governance bodies, which comprise largely industry and consumer representatives. Proposals for changes to codes can be made by any party to the code and are subject to a code governance process. Ofgem can accept or reject any code decision, subject to appeal where it overturns the decision of a code governance body. Ofgem can only propose code changes as a part of "strategic code review" process, which requires a case to be made for strategic, coordinated change. It should be remembered that all UK network companies are privately owned limited companies that a seeking to optimise shareholder value. It is not surprising that they act in a way that allows them to meet their obligations at least cost and to maximise the value of the incentive framework under which they operate.

Having said that, companies undoubtedly take a long-term view of shareholder value and recognise the important of meeting the expectations of important stakeholders (including regulators, government and the general public). Therefore, companies can be expected to "do the right thing" in some circumstances, regardless of commercial incentives; particularly in relation to maintaining and restoring supplies and meeting the needs of more vulnerable consumers. They will be acutely aware of the risk of a political or public backlash, which could lead to tougher regulations and lower returns in the future. But it is probably also the case that individual managers and operatives retain a degree of a public service ethos, and will take a degree of pride in delivering an essential service.

Control room practices

Both gas and electricity DNOs have multiple control rooms, of which we visited one for each sector.

The distribution networks are responsible for bringing gas/electricity from the national transmission network (High Pressure and High Voltage respectively) into the distribution network, where it will transport energy further through local supply networks. As one shift engineer explained, they 'just' move energy from here to there. Within that 'just' is a complex system of infrastructure and assets providing an essential service in a way that keeps everyone safe. This infrastructure is subject to detailed long-term maintenance schedules and immediate trouble-shooting, an array of relationships with other organisations, from the transmission operators to emergency services, local authorities, major energy suppliers and users, supply companies, maintenance and engineering contractors, asset and site owners and others.

The distribution control rooms carry out overlapping duties, primarily concerned with the smooth and safe running of the distribution networks. In operational time frames This includes central control and oversight of maintenance and repairs, responding to faults, maintaining verbal contact with engineers on site, as well as managing the remote data

system itself. Gas and Electricity networks use a SCADA (Supervisory control and data acquisition) system to collect data about system operation and status, to monitor and control the system remotely. Both employ rigorous safety procedures from desks, relying heavily on the combination of SCADA software and telephones. Both undertake routine operations and respond to issues that arise. As with any control room, the operators (shift engineers and shift managers) can be understood as operating remotely from a centre of operations. They are in touch with the infrastructure across the region through the data that they can see on screen that records the status of assets, and by telephone with site engineers engaged in maintenance and repair activities. They are also in contact with support engineers working in separate rooms, managing and improving the SCADA system, planning future maintenance work, or doing strategic planning.

The main functional differences between the two control rooms are the sheer number and complexity of assets on the electrical network which is more extensive than the gas network, the amount of distributed generation on the electrical network, which is also much greater and distributed to a finer degree than on the gas network, and the time sensitivity of operations on the electricity system, which typically requires a quicker response to changing circumstances. Gas control engineers have the additional task of forecasting day-ahead demand on their networks that they pass to the transmission network operator (National Grid) which electricity control engineers do not do. Gas control rooms forecast day ahead demand at five points during the day, using data on current gas levels and pressures combined with software that matches levels to previous patterns of use as an indicator of likely use based on season, weather, and other similar factors. Electricity control room engineers are not required to engage in forecasting.

Control room engineers are also employed on shift work contracts that follow different patterns in the different sectors Each shift includes shift managers and shift engineers. In both sectors, these were heavily male-dominated, with just one female engineer working in each of the two control rooms we visited.

The companies are also responsible for the training of new generations of engineers, who spend extended periods of observation and monitored operation at the control desk. Training is rigorous and lengthy (typically at least 18 months), starting with a period of classroom studies, learning the rules and regulations, and learning the layout of the networks and the particulars of all the assets on the system. Gas engineers have to have a good understanding of the various chemical formulations and calculations to assess the calorific value of gas, while electrical engineers will need to understand power system flows etc. In other words, training covers the behaviours and status of the plant and equipment, system management, regulatory processes and the routines and processes of the control room operations themselves. This means that control room engineers have to be able to work with attention to detail, on various digital operating systems, while multi-tasking on diverse situations, remaining calm and focused throughout, and alert to the potential significance of data that might be presenting on screen. As a shift manager described it, control engineers have to be "*people that really like problem solving and puzzles, have a really agile, flexible way of thinking. Not guys that are just a bit, "Well I've always done this this way, so that's how I want to do it."*

Control engineers also carry the responsibility for responding to regional or national emergencies, and would be in touch with the National Emergency Committee or COBRA if necessary. Electricity outages occur relatively frequently, but can often be restored with

relative ease once a fault is addressed. When electricity is cut, most domestic gas appliances cease to function, but remain in a safe mode where they can be restarted by the occupier once electricity is restored. Electricity loss can also mean that heaters and conditioning equipment for the gas distribution infrastructure may cut out, requiring on-site repair or starting up of on-site generators.

Gas outages, on the other hand, are much less frequent. When they do occur, restoration of supply is accompanied by on-site inspection of gas equipment, which can entail house-by-house inspections of gas boilers and ovens, etc, meaning that restoring gas supplies to multiple properties after an outage is a lengthy, expensive and challenging process. If the gas supply to a major conurbation was cut, estimates suggest it would take many months to restore it. For example, cutting the gas supply to London would probably take at least 3-6 months to restore. A loss of supply at Withensea in Yorkshire covering around 3000 houses took two weeks to restore representing a significant input of man-hours for inspections. Hence, where gas or electricity supplies are threatened, it would make sense to curtail electricity supplies first. In the case of a national emergency, gas would first be cut from major industrial users with prior agreement (via interruptible contracts), followed by other large scale users. Only in the last resort would households and small businesses be cut off. However, if gas is cut, householders would be reliant on electric heaters, thereby potentially causing a peak overload in the electricity supply. For these reasons, the response to gas and electricity transmission and distribution are co-ordinated, but this co-ordination does not feature in the daily workings of distribution control rooms in the ordinary run of events.

At present, the gas distribution network does receive inputs of biogas. These are operated according to supply contracts which specify the amount of gas and its chemical composition (calorific value). Biomethane calorific value reports are collected on a daily basis and evaluated over time. If there are significant discrepancies, a plant would be shut out of the system through an automated valve, and the operator would be asked to check the gas composition. Where biomethane plants are operated automatically, securing local checks can be challenging (eg especially where plant is owned by multinational corporations with offices abroad). At present, biomethane input to the Yorkshire and NE regional gas network are small enough not to affect either forecasts or operations to any significant degree. The question remains, though, how big would they need to be before both forecasting, pressurising and conditioning became significant?

Site integration

Site integration requires considerable reflection. If the future vision is to have energy from curtailed wind and solar plant being converted into hydrogen that is pumped into the gas networks, then several factors must be considered.

1. Where on the gas system should hydrogen be inserted? Should it be accommodated in the line-pack, in which case, it must be inserted at high pressure. Could it be accommodated in smaller quantities as biomethane currently is, and if so, what is the limit to the amount that could be accommodated?
2. Are there renewable electricity generation sites on constrained sections of the grid where it would be appropriate to install a hydrolyser? And are these also in the geographical location of the relevant pressure section of the gas network?
   Non-constrained sections of the electricity grid may not require additional storage options, while constrained sections may not be geographically suitable for sending hydrogen into the

gas system. How many sites currently meet these requirements? Can hydrogen be easily and safely transported from constrained locations on the power grid to suitable locations for injection in the gas grid?

3. Would weather and demand forecasting provide adequate information to allow estimates of hydrogen production to be fed into 24-hour gas forecasting systems? Would this be done at the distribution or transmission level? Does there need to be changes in the planning timescales and approaches to accommodate hydrogen injection.

Site specific questions require further investigation before the viability of using hydrogen for electricity storage/conversion to be evaluated.

Modelling

As part of this case study, a modelling exercise was undertaken to consider scenarios for gas and electricity distribution network integration, using a techno-economic-environmental evaluation framework. The mathematical representation of the networks is detailed in Appendix 2. The aim of the modelling exercise was to evaluate the operation of the gas and electricity networks under a range of scenarios, including the curtailment of renewable energy or its accommodation by a degree of integration of gas and electricity networks.

Four scenarios were implemented in order to investigate the extent of support of each network to the coupled network in case of any fault/network constraints. The first two assume the gas network supports the electricity network, the third assumes they remain separate, and the fourth assumes the electricity network supports the gas network, as follows:

1. the **Base Case**, which accommodates surplus Renewable Energy (RES) assuming the expected load and generation profile;
2. **Peak Demand** which accommodates surplus RES under peak load and generation profile; and
3. **Separate Networks** under which surplus RES is not accommodated.
4. Impact of heat load, with ramp up and down at peak heat load condition.

Together, the scenarios suggest that the base case scenario poses the best potential for future operation. Scenarios 2 and 3 had negligible costs for the electricity network in either technical, economic or environmental terms. The results show that the environmental cost to the gas network of keeping the networks separate is significantly higher than any of the scenarios in which the gas network supported the electricity network (by 24579kg to 18360/19903kg). The financial cost was also higher (997 vs 745/808). Hence there are significant savings to be made by integrating the networks with gas supporting the electricity network.

Next Steps

The modelling exercise shows that there are clear benefits to be gained by integrating electrical and gas networks in this way. Assumptions and methodologies used in this modelling exercise do need to be further examined, however, and a range of other

scenarios could be explored. In particular, assessing the potential for integration at other sites or where more significant renewable assets are being installed could give a much clearer idea of the potential for this form of integration. Broader, and deeper scenarios could be addressed, and critical scenarios could be estimate that outline at which scale renewable curtailment, hydrogen production, or gas integration the system starts to offer significant advantages. In other words, fuller planning and operational models could be developed to develop the scenarios.

In regulatory terms, a more detailed examination of codes and regulations would give a clearer outline of where attention must be focused on adapting the regulatory framework to enable further integration. A full risk assessment should also be developed to analyse the potential weaknesses that integration may entail – particularly in relation to system-wide failures or attacks. A more detailed regulatory review would help to outline where points of concern are to be found, such that these could be effectively addressed.

In terms of control room operation, it was notable that neither the gas nor electricity shift engineers had been in the corresponding control room on the other network. A useful empirical exercise would consist of asking shift engineers or shift managers to observe a shift in one another's network, using observation and interviews to help outline the key areas where they experience differences that could impact on communications between networks. Difficulties with larger scale change, and particularly in the case of system integration, are often most keenly anticipated by those who operate on the 'front-line' (or 'street-level' – see Lipsky 1980).

Further attention should be given to the role of transmission in integration. Currently, in relation to the NE, large scale renewable resources come under the remit of the National Grid transmission system, meaning that decisions on curtailment are taken above the distribution level. However, in some other distribution networks, active network management is more of a concern. Further research should include existing ANM operations in the UK, and potentially consider international comparative cases.

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Appendices

Appendix 1: List of relevant codes and standards (probably not exhaustive)

It is a requirement of licenced gas and electricity distribution networks to be a party to various codes and standards (not sure whether this is a licence requirement or a requirement in the relevant Act).

Electricity distribution

- **Distribution code.**This covers the technical aspects relating to the connection and use of the electricity distribution licensees' distribution networks. www.dcode.org.uk
- **DCUSA** (Distribution and Connection Use of System Agreement) relates to the connection to and use of the electricity distribution networks. It includes the charging methodologies for connection to, and use of, the electricity distribution networks.www.dcusa.co.uk

The **Grid Code** and the **CUSC** (Connections and Use of System Code) and the equivalent codes for electricity transmission. As distribution networks connect to the transmission network, these may be of some relevance. The Balancing and Settlement Code refers to the market for wholesale energy in Great Britain, which may have some relevance in respect of licenced embedded generators.

Some of the most important technical standards, as Engineering Recommendations (ERs). ER P2/7 for example, determines resilience standards for network planning, sit under the distribution code.

Gas distribution

- **UNC** (Uniform Network Code). All gas networks (transmission and distribution) and gas balancing is covered by the Uniform Network Code.

There are also various codes related to metering, specifically, to smart metering (the Smart Energy Code) and to the transfer of consumers between suppliers.

There are also standards of performance, which can be issued by Ofgem, under a condition in the electricity and gas licences. which includes the **Quality of Service Guaranteed Standards.** These set out standards for matters such as the speed of supply restoration, connections and voltage.

Suggested framework for looking at barriers in the way of whole system operation of gas and electricity networks.

1. Conflicting objectives.
    a. Commercial – each party, as a separate private company, will be seeking to optimise its own commercial position. Where an optimal outcome requires one party to incur a financial loss, there would need to be some means of payment to compensate for this.
    b. Reputational – each party, as a separate private company, will be reluctant to incur reputational or brand damage in order to deliver a better outcome from a whole system perspective. For example, a DNO would be reluctant to disconnect its customers, even if this helped resolve a problem on the gas network, which is likely to have greater impact overall.
    c. Regulatory – each party is required to further its own objectives, as set out in legislation and regulation. Despite the fact that 85% of electricity consumers are also gas consumers, it is likely that each party will be required to further the interest of their own set of consumers, without reference to the other party. It may also mean

that explicit consideration of the objectives of the other party is a breach of codes or licences (ultra vires).

2. Conflicting incentives.
    a. Each party will be seeking to optimise its performance with respect to the incentive framework in their respective licences, codes and standards. This may not always be in the best interests of consumers, particularly if there is some degree of interaction between the actions of each party.
    b. Incentives, targets and standards are inevitably imperfect and can distort the behaviour of network companies and act as a barriers to co-operation. For example, if one company is at risk of missing a standard and the other isn't, they will act in accordance with these standards rather than the wider interest of gas and electricity users.
3. Gas and electricity are physically different
    a. Gas and electricity have very different physical and engineering characteristics, and operate under very different operational and safety rules. One party is likely to be unfamiliar with the specific characteristics of the other.
    b. For example, the gas system is more tolerant of short-term imbalances and can withstand greater variations in pressure. The gas system generally needs to be balanced over a daily time frame rather than near instantaneous in the case of electricity.
    c. Also the consequence of a loss of gas supply is more profound, in that it is harder to re-connect lost supplies due to safety issues. The emergence of smart meters might reduce that difference.
4. Different cultures
    a. Undoubtedly, given differences in history and technical characteristics, there will be differences in culture, language, terminology, priorities, propensity to co-operate, inclination to consider the public interest first and so on.
    b. For example, I suspect the time criticality of electricity relative to gas may lead to differences in approach.

Appendix 2: The mathematical representation of the gas and electrical networks

1. Electricity network

The equation for balance of active and reactive power at all the buses of the electricity network, except the slack bus was formed as follows (Grainger, W. D. Stevenson, 1994):

$$P_{G_i} - P_{L_i} - \sum_{k=1}^{N_B} |V_i||V_k|(G_{ik}\cos(\delta_i - \delta_k) + B_{ik}\sin(\delta_i - \delta_k)) = 0 \quad (1)$$

$$Q_{G_i} - Q_{L_i} - \sum_{k=1}^{N_B} |V_i||V_k|(G_{ik}\sin(\delta_i - \delta_k) - B_{ik}\cos(\delta_i - \delta_k)) = 0 \quad (2)$$

in which:

P_{G_i} Active power generated at bus i

P_{L_i} Active load at bus i

N_B	Number of buses of the electricity network
V_j	Voltage magnitude of the bus j
G_{ik}	Real part of the element in the bus admittance matrix corresponding to the i'th row and k's column
δ_j	Voltage angle of the bus j
B_{ik}	Imaginary part of the element in the bus admittance matrix corresponding to the i'th row and k's column
Q_{G_i}	Reactive power generated at bus i
Q_{L_i}	Reactive load at bus i

2. Gas network

The equation for balance of gas flow at all the nodes of the gas network, except the source node, was formed as follows:

$$\sum_j q_{j,in} - \sum_j q_{j,out} - q_L = 0 \tag{3}$$

in which:

$\sum_j q_{j,in}$	Sum of all the gas flows entering node j from the branches connected to it
$\sum_j q_{j,out}$	Sum of all the gas flows leaving node j from the branches connected to it
q_L	Gas load at the node

The general gas flow equation was used to model the flow of gas within pipelines (Osiadacz, 1987):

$$q_k = \pi \sqrt{\frac{R_{air}}{8}} \times \frac{T_n}{p_n} \times \sqrt{\frac{(p_i^2 - p_j^2) \times D^5}{f.S_{mix}.L.T.Z_{mix}}} \tag{4}$$

in which:

q_k	Gas flow in branch k
R_{air}	Air constant
T_n	Standard temperature ($T_n = 288.15$ K [2])
p_n	Standard pressure ($p_n \sim 0.1MPa$ [2])
p_i	Pressure at node i
D	Pipe diameter
f	Friction factor
S_{mix}	Specific gravity of the gas mixture
L	Length of the pipe

T Temperature of the gas

3. Coupling component: Power-to-Gas (P2G)

The equation used for correlating the power consumption of the P2G unit and the gas flow production is (Hosseini, 2017):

$$q_{P2G} = \frac{P_{P2G} \times \eta_{P2G}}{GCV_{mix}} \tag{5}$$

in which:

q_{P2G} Gas flow production of P2G

P_{P2G} Active power consumption of P2G

η_{P2G} Efficiency of P2G

GCV_{mix} Gross calorific value of gas mixture

Appendix 3: Algorithm of techno-economic-environmental evaluation framework

The algorithm of Techno-Economic-Environmental (TEE) evaluation framework, which evaluates the TEE performance of Integrated Gas and Electricity Distribution Networks (IGEDN), is shown in a flowchart in Fig. 1. This framework assesses the impact of different levels of renewable sources, different levels of energy demand and different network configurations on the amount of imported energy from upstream networks, operation costs and emissions of IGEDN. The model is based on a coupled gas and AC electrical load flow model, facilitating the consideration of all the parameters affecting the operation of IGEDNs, such as different gas mixtures, the gas temperature, the pipeline characteristics, and the electrical network topologies, impedances and power quality.
In this study, the technical impact is represented by the energy imported from Upstream (estimated in MWh), the environmental impact is represented by the amount of emitted CO2 (estimated in kg.CO2.eq), and the economic impact is represented by the cost of energy imported from upstream (estimated in £).

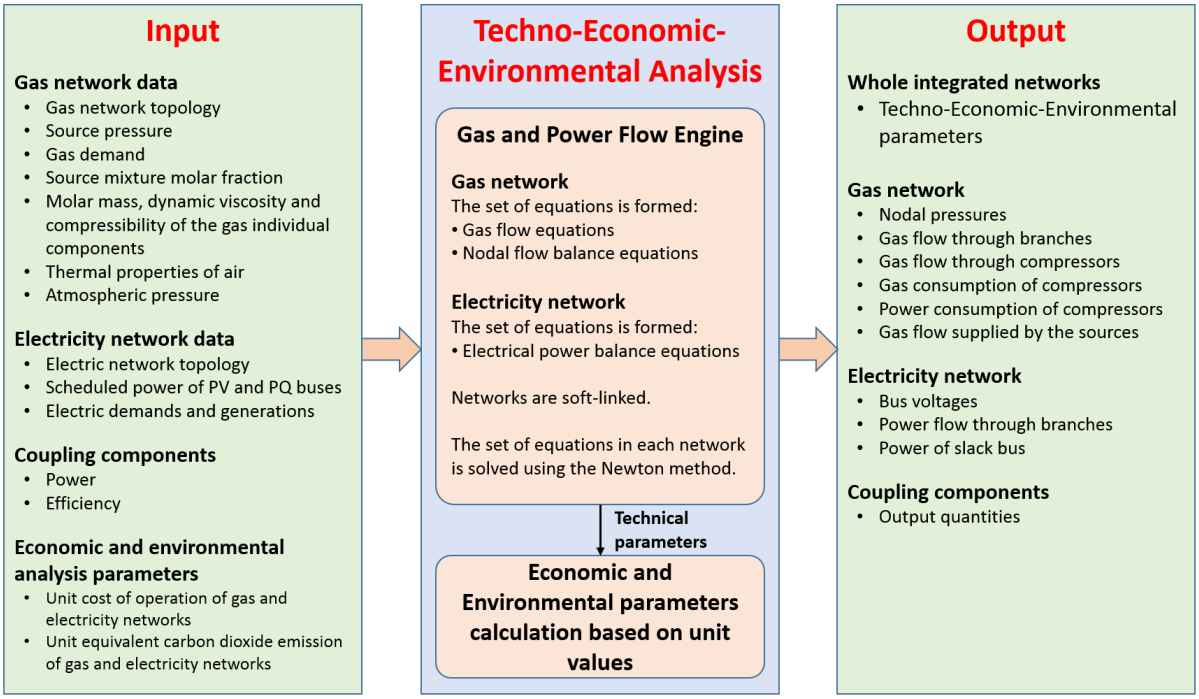

Fig. 1 Algorithm of TEE evaluation framework

Modelling case study

The case study used the distribution networks around Lower Thornley, where InTEGreL is located. The schematic diagram of these two networks integrated through a P2G is shown in Fig. 2. It is assumed that 'Gateshead central' bus in the electricity network is connected to the upstream of Low Thornley at 'LOWTRI' node in the gas network through a P2G.

The data of the both networks are obtained from Northern Power Grid (NPG) and Northern Gas Network (NGN), the models of networks have been built accordingly. The load of electricity network has been scaled down to match the demand in the gas network. This is because there is an uncertainty about the matching between the geographical areas covered by the two models' networks.

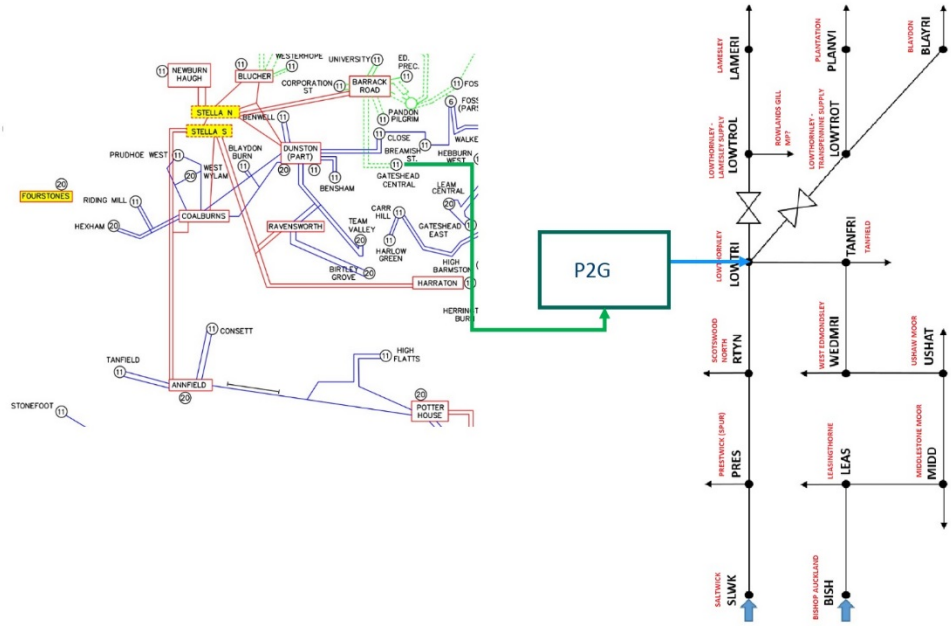

Fig. 2 Schematic of the integrated gas and electricity distribution networks around Low Thornley area

Four scenarios were implemented in order to investigate the extent of support of each network to the coupled network in case of any fault/network constraints. The first two assume the gas network supports the electricity network, the third assumes they remain separate, and the fourth assumes the electricity network supports the gas network, as follows:

5. the **Base Case**, which accommodates surplus Renewable Energy (RES) assuming the expected load and generation profile;
6. **Peak Demand** which accommodates surplus RES under peak load and generation profile; and
7. **Separate Networks** under which surplus RES is not accommodated.
8. Impact of heat load, with ramp up and down at peak heat load condition.

These scenarios are outlined in detail below:

A. Gas network supporting electricity network

- Scenario 1: Base Case - Accommodating surplus RES assuming expected load and generation profile (S1:Base case)

  Assumption: Electricity and heat load profiles as well as the RES generation including wind and PV profiles are forecasted and known.

  Action: Any surplus of RES that is going to violate operation constraints of the electricity network such as voltage limit violation in transformers, will be converted through a P2G and injected into the gas network as natural gas.

  Evaluation of considered action: Techno-Economic-Environmental (TEE) operational analysis of the integrated networks will be investigated.

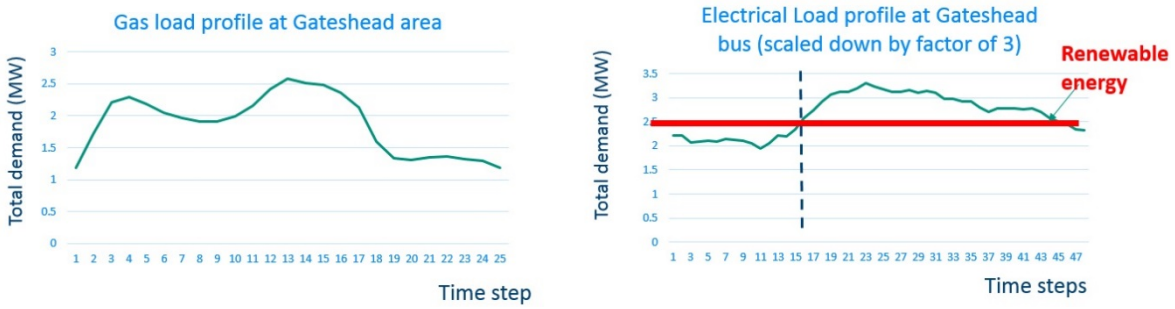

Fig. 3 The gas and electrical load profiles at Gateshead considered for Scenario 1

- Scenario 2: Peak demand - Accommodating surplus RES assuming peak load and generation profile

  This scenario is implemented in order to simulate the possible condition of great amount of RES and peak load occurring concurrently and to investigate the impact of high renewables at the same time as the peak load on TEE operational analysis of integrated networks.

  - **Assumption**: The loads profiles of base case scenario are 20% increased and the RES generation profiles are 80% increased.
  - **Action**: Inject the surplus renewable energy in the gas network
  - **Evaluation of considered action**: TEE operational analysis of integrated networks will be investigated.

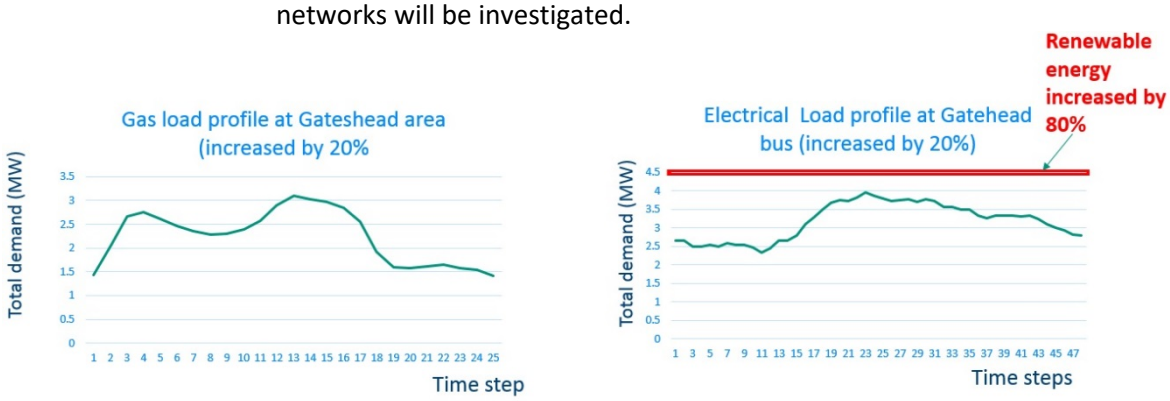

Fig. 4 The gas and electrical load profiles at Gateshead considered for Scenario 2

- Scenario 3: Networks are separated - Not accommodating surplus RES

  In this scenario surplus RES generation of base case will be curtailed and the impact on TEE operational analysis of the gas and electricity networks will be investigated.

  - **Action**: Surplus RES generation of peak scenario will be curtailed.
  - **Evaluation of considered action**: TEE operational analysis of the gas and electricity networks will be investigated

B. Electricity network supporting gas network

- Scenario 4: Impact of heat load - Ramp up/down of m-GT and CHPs at peak heat load condition
  - **Assumption**: condition of a peak heat load, which is met by gas, has occurred and the pressures on the gas network are close to violate the required pressure limit at the demand side.

- **Action**: In this case the possible m-GTs and CHPs need to be curtailed in order to reduce the gas demand on the gas network and relieve the pressures.
- **Evaluation of considered action**: TEE impact of this action on the gas network and pressures.

NB: To evaluate the technical-economical-environmental impacts of the four scenarios, the following parameters are considered.

Unit parameter	Gas network	Electricity network
Operational costs (£/MWh) *	9.42	28.06
Emissions (kg.CO2.eq/MWh)	232.00 **	270.00

Scenario outputs

The following tables summarize the technical-economical-environmental impacts of the 4 scenarios.

Table 1: Evaluation results of scenarios 1, 2, and 3			
Scenarios	TEE parameter	Gas network	Electricity network
Scenario 1	Technical (MWh)	85.79	6.541
	Environmental (kg.CO2.eq)	19903	1766
	Economical (£)	808.14	183.5
Scenario 2	Technical (MWh)	79.14	0.092
	Environmental (kg.CO2.eq)	18360.5	~0
	Economical (£)	745.5	~0
Scenario 3	Technical (MWh)	105.94	0
	Environmental (kg.CO2.eq)	24579.4	0
	Economical (£)	997.95	0

Table 2: Evaluation results of scenario 4				
Scenarios	TEE parameter	Gas network	Electricity network/CHP curtailed	Electricity network/CHP fully capacity
Scenario 4	Technical (MWh)	270.94	28.375	16.37
	Environmental (kg.CO2.eq)	62858	7661.25	4419.9
	Economical (£)	2552	796.2	459.34