E3C

Opportunities Report

Review of the Impact of a Gas Supply Shortage on the Electricity System (RIGSSE)

Executive Summary

This Opportunities Report provides a detailed, and evidence-based, explanation of eight opportunity areas which were identified following the project's stakeholder engagement period. Collectively the opportunity statements below aim to collate the knowledge and learning gained from stakeholder opinion, they read:

> *Opportunity Statement 1: When there is a shortage of gas, or restrictions on the ability to transport gas, which leads to an impact on electricity generation there is currently no coordinating body with the authority to make whole energy system decisions.*
> *Opportunity Statement 2: The ability for the GSO and ESO to share situational awareness pre-emergency is limited by both parties' licence conditions on information sharing, leading to uncoordinated actions being taken which are potentially disproportionate*
> *Opportunity Statement 3: OC6 is currently the primary means of demand control on the Electricity system. OC6 does not consider the priority site list and could leave consumers without electricity supplies for an undetermined period of time.*
> *Opportunity Statement 4: A large number of embedded generation sites are classified in the LDZs as small sites and are not required to share forecasting information or emergency contact details leading to potentially unforeseen demand increases.*
> *Opportunity Statement 5: The current gas load shedding hierarchy targets the largest transmission connected gas generators over smaller distribution connected gas generators.*
> *Opportunity Statement 6: There is a lack of whole energy system coordination to the issuing of warning notices and pre-emergency market incentive tools. Industry behaviour may therefore be unsupportive of the maintenance of whole energy system health.*
> *Opportunity Statement 7: There is currently no force majeure clause in electricity capacity contracts to cover when generators are load shed under a Network Gas Supply Emergency (NGSE).*
> *Opportunity Statement 8: The instruction to Load shed sites which rely on heat to maintain machinery/product is overly damaging to industrial sites.*

Each opportunity within this report is presented in a tabular format detailing:

- The **Opportunity Statement**.
- A **Background Statement.** The Project Teams' view of the Impact of this opportunity remaining unsolved.
- Evidence from **Real World** incidents in support of opportunity statement.
- Evidence from simulated **Emergency Exercises** in support of opportunity statement.
- **Factual** reference information.
- Extracts from the **Stakeholder Engagement** report which detail stakeholder support for solving the opportunity.

Contents

1 - Overview

The RIGSSE Project Team conducted stakeholder engagement during February- April 2021. The findings of this engagement are fully documented in the RIGSSE Stakeholder Engagement Report.

This Opportunities Report provides a detailed, and evidence-based, explanation of 8 opportunity areas which were identified following the project's stakeholder engagement. Each opportunity is presented in the later sections of this report in the following format:

Opportunity Statement: The statement details the area of GB Gas and Electricity interaction which present an opportunity to develop further. Improvement options should in combination solve the RIGSSE problem statement.

Background: Further contextual information is provided for each opportunity statement.

Impact: Project Team view of impact caused by the opportunity remaining unresolved. Information gathered from literature review, Project Team expertise and wider industry expert opinion.

Real world examples: Evidential examples of the detrimental interplay experienced as a result of the opportunity remaining unresolved.

Real world considerations: Where the detrimental interplay has not practically occurred, or where the occurrence has not been impactful, the perceived risks are listed.

Exercise examples: Evidence of where a detrimental interplay has been simulated in recent industry exercises is provided.

Factual information: Factual information is provided in the form of extracts from current incident and emergency processes, existing contracts or extracts from legislation.

Stakeholder support: Engagement summaries are provided in the final section to demonstrate the supporting evidence obtained from industry engagement.

2 - Opportunity evidence tables

Opportunity 1

Opportunity Statement:

When there is a shortage of gas, or restrictions on the ability to transport gas, which leads to an impact on electricity generation, there is currently no coordinating body with the authority to make whole energy system decisions.

Background:

Energy system responses are already robustly overseen by government. There is however currently no one coordinating body with the predetermined authority to make prompt whole system energy emergency decisions in the event of a gas supply shortage. This leads to the risk of an uncoordinated response across the whole energy system which could have unnecessary safety, financial and disruptive consequences. Current measures under the Network Emergency Coordinator (NEC) role would consider electricity system stability only to ensure continued operation of the gas network.

Impact (project team view):

That there is no coordinating body with the authority to make whole energy system decisions has the potential, when there is a gas supply shortage, to trigger either system's demand control measures, which may cut off priority and domestic energy load. It is assessed that the likelihood of demand control measures being averted, delayed or reduced in severity would increase should a coordinating authority be responsible for overseeing a whole system response in the event of a gas supply emergency.

Gas supply disruptions ultimately need to be met by a reduction in energy demand. Options to define a new form of whole energy system coordination will not change this but, it is assessed that an enhanced level of whole energy system coordination could accurately assess impact assisting in forming decisions on demand control application which is least impactful to priority users and the most vulnerable in society.

The Gas Network Emergency Coordinator currently has the following powers:

- The NEC is given legal powers under GS(M)R to direct industry participants during an emergency
- The NEC considers the impact of gas firm load shedding on the electricity network, only from the perspective of whether it will increase the public safety risk brought about by instability in the gas network
- Currently, the authority of the NEC can only be supplanted by an order of council under the energy act to instruct deviation from the safety case.
- The process, of sourcing an order to contradict existing regulation, would likely delay the response process beyond a reasonable timeframe

Introducing an additional form of coordination beyond the existing powers of the Gas NEC is a consideration. Fundamental to this coordinator's abilities is pre-emptive powers of direction. The application of which may require the drafting of a new form of regulation under the Energy Act 1976. The Energy Act does currently contain reserve powers by which directions can be given by the Secretary of State to avert or mitigate an energy supply emergency. There are limitations to these powers, fundamentally that they require an Order in Council to activate them. Sourcing an Order is a laborious process which would likely not be completed in time to mitigate the actions taken on the energy systems. The 'Factual Material' table, below, outlines these limitations in full.

Real world examples:

- **Beast from the East 1st March 2018** – The last real-world activation of the pre-emergency suite of tools on the Gas Network occurred on 1st March 2018 and saw the use of Operating Margins and activation of a National Off-Peak Exit Capacity Scale-Back.
  - The utilising of **Operating Margins** saw the contractual instruction of one power station to reduce their consumption of gas, which they complied with.
  - Activation of a **National Off-Peak Exit Capacity Scale-Back** saw all power stations comply, with none overrunning from their agreed firm capacity volume.

  On this day the Electricity Network was <u>not</u> in parallel stress and was being supplied by a diverse mix of fuel types, therefore less reliance on gas fired generation during the gas day (gas generation represented 23% of the overall generation mix).
- **9th August 2019 – Automatic Demand Disconnection** – Though not triggered by a shortage of gas, the last real-world example of how impactful a loss of electricity supplies can be to GB occurred following an Automatic Low-Frequency Demand Disconnection (LFDD). This rapid means of demand reduction is similar to the Demand Control tools of OC6 in that the required amounts of demand are removed quickly, without the ability to avoid the loss of supplies to Priority Service Register nor Priority Site List Electricity consumers. This example serves to demonstrate that, without a form of whole energy system coordination, the current frameworks are unable to assess impact to the parallel system potentially leading to overly impactful measures being taken to reduce demand. This example demonstrates this impact through the short-term loss of electricity supplies. If Demand Control under OC6 were to be required, to counter a shortage of gas fired generation, it would target at least 5% of electricity system demand and would last for several hours.

Real world considerations:

- Unplanned asset faults on either network.
- A shortage of Gas Supplies when gas fired generation provides the majority supply source for the Electricity System.

Exercised examples:

Exercise Baltic (2020): Exercise Baltic demonstrated the impact a loss of gas fired, transmission connected generation could have on electricity consumers, even before a Network Gas Supply Emergency is declared:

Day 1: Pre-Emergency	7 Million electricity consumers off supply 16:00 to 22:00
Day 2: Emergency	13 Million electricity consumers off supply 10:00 to 22:00

* Figures are specific to the heightened exercise scenario

The Exercise Baltic report states that 'when there is a gas supply shortage there is an unassessed impact on the electricity network. This impact needs to be pre-emptively understood and more effectively coordinated'.

Stakeholder Support:	
Electricity and gas working alongside each other needs joint decision making - talking all the time making the right commercial decision within the remit.	A comparative impact assessment can be carried out jointly with both gas and electricity input. This will enable a whole system overview and thus better decisions can be made.
Ireland utilises a council of stakeholders in the form of the GERT to share information across fuels	During a gas emergency the NEC can look across both systems and compare information providing more information on how to make decision, but we don't have that until an emergency is declared.

Factual Information:

Allowing either System Operator a form of derogation from their licence, to avoid detrimental impacts of a pre-emergency tool, is manageable within Ofgem's governance.

The direction of the Network Emergency Coordinator (NEC), during a Network Gas Supply Emergency (NGSE), is more problematic. The NEC must take action to prevent a loss of pressure in the Gas Network. If these actions were overly impactful to the Electricity System, in order to contradict the directions of the NEC, the Secretary of State would be required to progress an Order in Council. This order would likely not be sufficient to direct the NEC itself. Instead it would be given to the undertaking whom had originally been directed by the NEC - serving to contradict the original instruction.

This process, of sourcing an order to contradict existing regulation, would likely delay the response process beyond a reasonable timeframe, could cause confusion and legal objection, and there is no other means to prevent gas fired generation from being load shed from the Gas Network. The only exception to this is detailed in the NEC Safety Case Section 4.3

This exception is designed to protect the gas network. Therefore, that load shedding causes the electricity system to enter OC6 measures is not an admissible consideration to the NEC's decision-making process unless this is deemed to risk instability to the gas network.

There are key powers under the Energy Act 1976 which allow the BEIS Secretary of State to regulate or prohibit the production, supply, acquisition or use of natural gas or electricity. These powers are considered 'by order' in the conservation of energy, and 'by reserve' (requiring an Order in Council) for any purpose. An order in council is required at all times in order to direct undertakings that use, produce or supply natural gas and electricity, and to grant authorisations by which legislative or contractual obligations are disapplied in respect of the relevant person.

Opportunity 2

Opportunity Statement:

The ability for the GSO and ESO to share situational awareness pre-emergency is limited by both parties' licence conditions on information sharing, leading to uncoordinated actions being taken which are potentially disproportionate.

Background:

Current licence conditions require complete separation of market and operational awareness between both control rooms pre-emergency. This leads to a risk that operational decisions taken by one control room may inadvertently not support whole system security and potentially constitute an unnecessary expense to consumers. There is already an exemption to this condition which allows full and open information sharing once a Network Gas Supply Emergency (NGSE) has been declared.

Impact (project team view):

Either fuel may under or over utilise instructions and constraint management tools when using only public information to establish situational awareness. In the first instance this represents financial implications to the industry and consumers. In more serious circumstances this could see disruptive impacts, as a result of unnecessary instruction or use of constraint management tools, and the potential for demand control measures to be taken unnecessarily.

Real world examples:

- **Beast from the East 1st March 2018** - The last real-world activation of the pre-emergency suite of tools on the Gas Network occurred on 1st March 2018 and saw the use of Operating Margins and activation of a National Off-Peak Exit Capacity Scale-Back.
  - The utilising of **Operating Margins** saw the contractual instruction of one power station to reduce their consumption of gas, which they complied with.
  - Activation of a **National Off-Peak Exit Capacity Scale-Back** saw all power stations comply, with none overrunning from their agreed firm capacity volume.

  On this day the Electricity Network was <u>not</u> in parallel stress and was being supplied by a diverse mix of fuel types, therefore less reliance on gas fired generation during the gas day (gas generation represented 23% of the overall generation mix).
- **Constraint management tools** used by either network impacting the other network - Constraint management tools have been utilised by the GNCC 5 times within 2020 and 7 times within 2021. These occasions constitute times of potential elevated risk for the electricity network depending on the active generation mix at that time. These decisions are taken by the GNCC without any knowledge of the potential strain that may occur within the ENCC. It is possible that the use of these tools will result in flexible electricity generators becoming inflexible at high power output levels in the Electricity Balancing mechanism. This may result in cost/security issues in low demand periods when the ESO requires flexibility to reduce power output levels from these generators. To manage this situation the ESO may incur higher costs than is necessary or be required to issue Grid Code warnings and take Emergency action.

Real world considerations:

- Unplanned asset faults on either network.
- In 2020 gas fired generation accounted for an average of 34.5% of the annual electricity supply mix, but this can peak beyond 60% of the total supply make up on a given day, and especially during the winter - which is also when the Gas Network is most vulnerable to a gas supply shortage.

Case study: Number of days gas generation made up more than 50% of the electricity supply mix

Winter 19/20	Summer 2020	Winter 20/21
21 days (Average 3.5 days per month)	**49 days*** (Average 4.5 days per month)	**27 days*** (Average 4.5 days per month)

* Covid-19 lockdown measures active during data period

Highest % of gas in a settlement period (2020)	Highest % of gas in a day (2020)
74% (27th Aug 20)	**67%** (16th Jun 20)

Exercised examples:	
	Exercise Zeus (2018): served as an opportunity to build on the current understanding of gas and electricity interaction. The exercise demonstrated that it was extremely difficult to achieve a cross system understanding of the impacts of a reduction in gas fired generation. Different units of measurement and balancing periods impeded the conversation and the ENCC concluded that a loss of gas fired generation would be serious for the electricity system, but better data was required.
	Exercise Arctic (2019): The findings from Exercise Zeus led to a core objective for Exercise Arctic to continue this level of engagement from the electricity sector in the NEC exercise going forward. Furthermore, Exercise Arctic's parameters were set to allow the GNCC and ENCC to speak openly (without fear of recourse to their licence conditions - within the confines of the exercise scenario) and trial the use of a newly designed information sharing tool. Exercise Arctic demonstrated that open communications were essential to cross system understanding. Even with the ability to speak openly, responders were limited in their ability to calculate impact by their understanding of each other's networks.
	Exercise Baltic (2020): cemented an understanding of the seriousness of a shortage of gas to the electricity system using live data in the scenario, open communications and expanded use of the information sharing tool. Though a perfect storm of gas supply losses was scripted, gas demand data and electricity supply and demand data were live. When gas fired generation was load shed the ESO calculated that 13 million electricity consumers would lose their supply through the requirement to activate the demand control elements of OC6 to rebalance the electricity system. The use of the gas system's pre-emergency tools was also simulated in Exercise Baltic, though the parameters of the gas market responding to the use of these tools was not accurately simulated. The ESO did however apply, to this pre-emergency live data, the worst-case scenario for the electricity system, that all gas fired generation on the NTS complied with the suite of pre-emergency gas system tools. This led the ESO to calculate that 7 million electricity consumers would lose their supply through the requirement to activate the demand control elements of OC6 to rebalance the electricity system.

<table>
<tr><th colspan="2">Stakeholder Support:</th></tr>
<tr><td>Ireland utilises a council of stakeholders in the form of the GERT to share information across fuels</td><td>So long as the reason is transparent to industry, the GSO and ESO should be allowed to 'be in the same place' for better coordination</td></tr>
<tr><td colspan="2">The pinch point of different balancing approaches will be most evident in the event of an emergency, compounded by the lack of ability to communicate between GSO and ESO. If there is a different approach, it provides inconsistency in comparative risk assessment and thus in response.</td></tr>
<tr><td>Getting everyone to communicate is difficult, the two sides won’t speak to each other.</td><td>Unless an emergency is declared, ESO and GSO do not have the ability to freely communicate - meaning the ability to perform a comparative risk assessment is greatly reduced.</td></tr>
<tr><td>“It’s confusing to know which network to support and what to do”</td><td>Electricity and gas working alongside each other needs joint decision making - talking all the time making the right commercial decision within the remit</td></tr>
<tr><td>An issue of concern post Exercise Arctic</td><td>Opinion shared regarding the concept of an Independent System Operator and benefits regarding sharing of information</td></tr>
</table>

Factual Information:
NGGT Licence
There are two limitations on information sharing in NGGT’s license which impact the ability to liaise with the ESO in a developing or pre-emergency situation.
NG ESO Licence
The ESO must ensure that all employees (incl. contractors, consultants etc.) ensure that SOFI is not shared with or used by anyone outside of the ESO other than as per the exceptions set out in Special Conditions. Exemptions to the information ringfence obligations allow sharing of information between the ESO and other National Grid parties (e.g. the ETO, the shareholder, shared services teams working for the ESO etc) in specific, legitimate circumstances.

Opportunity 3

Opportunity Statement:

OC6 is currently the primary means of demand control on the Electricity system. OC6 does not consider the Priority Site List and could leave consumers without electricity supplies for an undetermined period of time.

Background:

If the Electricity System Operator wishes to enact demand control it will instruct the Distribution Network Operators to achieve this via Grid Code section OC6. OC6 is a rapid and effective method for reducing electricity demand, but this method of demand control does not have the ability to avoid impacting Priority Site List or Priority Service Registered users

Impact (project team view):

OC6 demand control (manual and automatic) arrangements do not specify the protection of priority or vulnerable customers – this lack of granularity is what makes OC6 demand control quick and effective to implement and DNO systems can be set up to disconnect demand at higher voltage levels. It is significantly more complex and costly to apply this at a lower voltage level, which may allow increased ability to protect specific customers or parts of the network. As such if OC6 demand control was in place for many hours (as is likely during a gas/electricity shortage situation) then vulnerable customers could be without supplies for a prolonged period.

It is worth noting that this impact on priority electricity customers could be during a period when gas industrial consumers are still connected to the network.

It is possible to achieve a greater level of protection to consumers through the Electricity Supply Emergency Code (ESEC) arrangements which ensure supply to registered protected customers for as long as is possible and will ensure that any rota disconnection of supplies is limited to a 3-hr block.

DNOs have indicated to the project team that early initiation of ESEC arrangements (during an emerging gas/electricity shortfall situation) would potentially provide greater protection for vulnerable customers by giving DNOs more time to prepare.

Currently ESEC requires the Secretary of State to initiate and would only be applied during a prolonged period of electricity shortfall.

Real world examples:

OC6 demand control has been delivered 3 times since 2000 to rectify national electricity supply imbalance:

- 27th May 2008
- 11th February 2012:
- 9th August 2019:

There were 6 Electricity Margin Notices (which are a potential precursor to demand control) issued during the 2020/21 winter due to shortages in electricity margin over Darkness Peak periods:

- Wed 4th Nov
- Thu 5th Nov
- Sun 6th Dec

- Wed 6th Jan
- Fri 8th Jan
- Wed 13th Jan

9th August 2019 – Low Frequency Demand Disconnection – As noted above a real-world example of how impactful a loss of electricity supplies can be to GB occurred following an Automatic Low-Frequency Demand Disconnection (LFDD). This rapid means of demand reduction is similar to the Demand Control tools of OC6 in that the required amounts of demand are removed quickly, without the ability to avoid the loss of supplies to Priority Service Register nor Priority Site List Electricity consumers.

The consequences of these events were significant and included:

- 1.1 million electricity customers without power for between 15 and 45 minutes.
- Major disruption to parts of the rail network, including blocked lines out of Farringdon and Kings Cross stations along with wider cancellations and significant delays impacting thousands of passengers. A major contributor to the disruption relates to a particular class of train operating in the South-East area – approximately 60 trains unexpectedly shut down when the frequency dropped below 49Hz, half of which required a visit from a technician to restart.
- Impacts to other critical facilities including Ipswich hospital (lost power due to the operation of their own protection systems) and Newcastle airport (disconnected by the Low Frequency Demand Disconnection scheme).

In the above example the OC6 LFDD process worked exactly as designed and protected the vast majority of electricity users and wider power system from significant disruption. However, it also serves as an example of how OC6 demand control cannot in its current form consider the needs of priority customers due to the requirement for quick, effective and efficient response.

If OC6 arrangements were required to counter a shortage of gas fired generation, it would target at least 1.5-5% of electricity system demand and would last for hours – as would potentially the disruption noted in the above example.

The Electricity Supply Emergency Code (ESEC) describes the steps which UK Government might take to deal with an electricity supply emergency of the kind envisaged under section 96(7) of the Electricity Act 1989 or section 3(1)(b) of the Energy Act 1976.

It also sets out the actions, which companies in the electricity industry should plan to take and which may be needed or required to deal with such an emergency.

ESEC enables, in the event of an emergency, an equal distribution of supply to customers as far as it is reasonably practical to do so. **It also ensures that local protected customers maintain supplies for as long as possible.** However, it is anticipated that, in their current form, ESEC arrangements would take 48 hours to initiate.

ESEC rota load disconnection arrangements were last used during the 3-day working week associated with the miner's strike, January - March 1974.

Real world considerations:
• Unplanned asset faults on either network. • A prolonged period of shortage of Gas Supplies when gas-fired generation provides the majority supply source for the Electricity System.

Exercised examples:	
	Exercise Baltic (2020): During Exercise Baltic (through incident simulation) up to 13 million customers were instructed off via OC6 demand control arrangements, in a real-life situation this would not take account of PSL or PSR registers (no protection for customers). At the peak of the day this demand reduction was approximately 35% of the total electricity transmission system demand (13GW of a peak of 38GW). Of the 13 million customers it is estimated that approximately 3.1 million are registered PSR customers. It is also worth noting that under OC6 it is necessary to provide DNOs notice the day before to ensure they are able to provide demand control greater than 20% of their demand, although greater than this will always be provided on a best endeavours basis. If the 13 million customers had been instructed off by ESEC arrangements, then customers on the PSR would have their demand protected. This can total up to 10% of total DNO demand. ESEC arrangements can take up to 48 hours to activate and put in place which is currently not in line with the timescales required to manage a gas emergency.

Factual Information:

OC6 high level summary
Should insufficient operational margins continue to be unavailable to maintain the security of the electricity system then it may be necessary for the ESO to instruct demand control. This will be an instruction to the distribution network operators and is defined in Grid Code OC6, specifically:

The reduction of up to 20% of the Demand on its System in incremental stages of which it will be expected that stages 1 and 2 will be specified by Voltage Reduction to give an average of 1.5% per stage and delivered within 10 minutes, followed by up to 3 stages of Demand Disconnection giving between 4 and 6% reduction.

- *NB: Each DNO licence area tests its stages 1 & 2 by Voltage Reduction initiated by ESO instruction every year. The results are presented to the E3C Electricity Task Group.*

- Alternately where timescales require, 4 stages of Demand Disconnection giving between 4 and 6% of Demand Reduction will be available to be delivered within 5 minutes.

- The reduction of up to a further 20% (40% in total) of the Demand on its System in Incremental stages of 5%, which can be achieved following the issue of a "High Risk of Demand Reduction" by ESO by 16:00hrs day ahead, which will specify the number of 5% stages (including the 20% always available) that ESO may require to be implemented.

In extreme circumstances when very short-term generation losses occur over and above the required security standards then automatic Low Frequency Demand Disconnection required under Grid Code OC6 will activate to preserve overall system security.

In the event of a long-term generation deficit scenario then it is possible that the UK government may enact the Electricity Supply Emergency Code (ESEC) arrangements to manage rota load disconnections.

The purpose of the Electricity Supply Emergency Code is to describe the steps which UK Government might take to deal with an electricity supply emergency of the kind envisaged under section 96(7) of the Electricity Act 1989 or section 3(1)(b) of the Energy Act 1976. It also sets out the actions, which organisations within the electricity industry should plan to take and which may be needed or required in order to deal with such an emergency.

- ESEC enables, in the event of an emergency, an equal distribution of supply to customers as far as it is reasonably practical to do so.
- It also ensures that local protected customers maintain supplies for as long as possible.

Stakeholder Support:
• OC6 Demand Control measures do not preserve electricity supplies to Priority Sites nor Priority Service Register customers. • Rota Load Disconnection under ESEC maintains supplies to Priority Sites and is less impactful to Priority Service Register customers thanks to rotating demand control versus one tranche of consumers being without electricity indefinitely. • It is possible to reduce the lead time in the activation of ESEC rota load disconnection in the distribution licence areas. • Significantly higher workload for DNOs to action ESEC in comparison to OC6 demand control.
• Protecting vulnerable customers is a high priority. • Minimising the time which consumers are without supplies is essential. The impact vs time consideration is exponential. • The key high-risk groups are priority service register consumers.

Opportunity 4

Opportunity Statement:

A large number of embedded generation sites are classified in the LDZs as small sites and are not required to share forecasting information or emergency contact details leading to potentially unforeseen demand increases.

Background:

Gas Local Distribution Zone demand is categorised according to annual gas usage, which then determines a customer classification (e.g. VLDMC, categories 1-4). Currently, a number of embedded generation connections fall into the lower classification categories which do not require them to share forecasting information or emergency contact details (categories 3 &4). In the event of load shedding on the gas network currently the lowest two categories (categories 3 & 4) are not daily metered, are not required to share forecasting information, or emergency contact details. During gas system stress, there is a risk that these sites may be generating close to their maximum output to respond to electricity market incentives. This behaviour may cause demand increases which are difficult to manage.

Impact (project team view):

Embedded Generation Registers available from the ENA portal show that up to 30% of the capacity of embedded generation on DNO networks is fuelled by fossil gas.

The following data has been taken from the Embedded Generation Registers, which cover all GB embedded electricity generation connections > 1MW. The DNOs have recently had code changes (Distribution Connection & Use of System Agreement) to obligate them to provide this information, and the datasets are still being populated and quality checked.
https://www.energynetworks.org/industry-hub/databases

Distribution Network Operator (DNO)	Embedded Gas Generation Installed Capacity (fossil gas) MW	Total Embedded Generation Installed Capacity MW	Embedded Gas Generation as % of Total Embedded Generation
Electricity North West	963	2,702	36%
Northern Powergrid	2,599	8,626	30%
Scottish Power Energy Networks	1,200	8,944	13%
Scottish & Southern Electricity Networks	*	4,936	-
UK Power Networks	3,503	15,912	22%
Western Power Distribution	*	20,977	-

* Missing or incomplete data

Although no data is available to show what volume of this generation would run under a system stress event it is clear that such high volumes will have a significant impact on flows on the DNO networks.

A data request has been issued to the Gas Distribution Networks requesting further information as follows:

- Number of generation connections across networks which are not daily metered
- The number of these connections for which you don't have emergency contact information
- The annual demand quantity of this group of connections
- The maximum demand you could see this group of connections take in a day

The results of this request will be added to this document when received.

Already received from one GDN is that their networks contain c.1000 MW of embedded generation capability.

Real world considerations:

- An exponential increase in embedded generation connections is forecast.
- The issue of Electricity System warning notices when there is a shortage of gas supplies will likely see an increase in demand from embedded generation which is difficult to forecast.

Exercised examples:

Exercise Baltic (2020): Recent emergency exercises have not factored the behaviour of generation embedded into the Gas Local Distribution Zones, in the scenario. It is assessed that factoring embedded generation into the scenario would have the following impact on the response during Exercise Baltic:

- Pre-emergency measures to incentivise demand reduction on the NTS would likely see embedded generation in the LDZs increase.
- An increase in demand in the LDZs during the pre-emergency phase would likely require the declaration of an NGSE earlier than simulated in Exercise Baltic.
- The demand control measures of the ESO during the pre-emergency phase of the exercise would likely be less severe if an upturn in embedded generation were factored into calculations.
- The required demand reduction in load shedding during the stage 2 NGSE would likely be required to be more severe if demand increases in the LDZ due to an increase in embedded generation were to be factored.
- The demand control measures of the ESO during the emergency phase of the exercise would likely be less severe if an upturn in embedded generation were factored into calculations.
- The declaration of a Stage 3 emergency requiring isolation of areas of the LDZ would likely be declared earlier if an upturn in embedded generation were to be factored.
- A further stage of demand control would likely be required by the ESO if the isolation of embedded generation sites were to be factored during the isolation of areas of the LDZs.

Factual Information:

The Gas Uniform Network Code Transportation Principle Document Section G outlines the classes of supply point:

2 SUPPLY POINT AND SUPPLY METER POINT CHARACTERISTICS

2.1 Classes of Supply Point

2.1.1 Each Supply Meter Point shall be classified as a “Class 1”, “Class 2”, “Class 3” or “Class 4” Supply Meter Point and references to a Class 1, 2, 3 or 4 Supply Point shall be construed according to the Class of the Supply Meter Point comprised in the Supply Point.

2.1.2 Subject to the further provisions of this paragraph 2.1 and paragraph 2.2, a Supply Meter Point shall be:

(a) in Class 1 where:

(i) the Class 1 Requirement applies, and

(ii) the Class 1 Meter Read Requirements are satisfied

(b) in Class 2, Class 3 or Class 4 where: (i) the Registered User has elected that it should be in such Class, and (ii) the Class 1 Requirement does not apply

2.1.3 The Class 1 Requirement applies in relation to a Supply Meter Point if:

(a) the Supply Meter Point is a NTS Supply Meter Point, or

(b) the Annual Quantity of the Supply Meter Point is not less than 58,600,000 kWh (2,000,000 therms), or

(c) the Supply Meter Point is Interruptible; or
(d) the Supply Meter Point is comprised in a Seasonal Large Supply Point;
(e) the Supply Meter Point is comprised in a Supply Point in respect of which the circumstances set out in the Distribution Network Operator Designated Class 1 Guidance Document apply; or
(f) the Supply Meter Point is an LDZ Supply Meter Point where telemetry equipment has been installed in accordance with Section M6.7.1.

2.3.1 The "Annual Quantity" in respect of a Supply Meter Point or Supply Point is an estimate (determined by the CDSP in accordance with the further provisions of the Code) of the quantity of gas which would (on a seasonal normal basis, in the case of a Class 3 or 4 Supply Meter Point) be offtaken from the Total System at that Supply Meter Point in a period of 12 months. Where the Annual Quantity in respect of the Supply Point is greater than 732,000 kWh (25,000 therms), the details (for making contact in an Emergency) required under Section Q2.3;

Further details of the rules which apply to each class of supply point are detailed in:

- Section H - Demand Estimation and Demand Forecasting
- Section J - Exit Requirements
- Section Q - Emergencies

Stakeholder Support:
• Local Distribution Zone generation classification is a concern, linking to lack of awareness of both flow forecast information and contact details for smaller generators. • Smaller independent generators are very price sensitive to when they do or don't generate
• A large number of embedded generation sites are classified in the LDZs as small sites which are not daily metered and do not require to share forecasting information nor emergency contact details • The collective behaviour of embedded generators can create spikes in demand which are difficult to forecast • During the response to stress or emergency events these spikes in demand could be more severe due to action being taken to reduce the demand of NTS connected generation.

Opportunity 5

Opportunity Statement:

The current gas load shedding hierarchy targets the largest transmission connected gas generators over smaller distribution connected gas generators.

Background:

The current load shedding hierarchy is designed to remove the largest loads from the gas network as promptly as possible. The hierarchy begins by removing Very Large Daily Metered (VLDMC) load from the gas network (both NTS and LDZs) before moving to reducing load from the next tranche of demand in the Local Distribution Zones (LDZs), which also prioritise removing their largest loads first. This design removes the larger high efficiency generators first which provide electricity system balancing/operability services as well as generator capacity. The gas demand of larger generators is well understood and more easily instruct-able in the event of system stress. There is a risk that both networks may experience unnecessary system security issues as a result of current gas load shedding design. Furthermore, the future of the electricity system is expected to see a large increase in embedded generation connections, compounding this issue.

Impact (project team view):

Gas considerations

Load shedding in an emergency is used to reduce demand to match available supplies. The system must achieve an end of day balance or risk uncontrolled failure.

Load shedding industrial demand on the Gas Network is highly time sensitive, as demand is continuously being consumed and the gas network is balanced on an end of day basis. To illustrate this, the following two examples (A & B) utilise simplistic values.

Example A: If 10 industrial customers are consuming 240mcm between them at a consistent rate from the start of the gas day (05:00hrs) to the end of the gas day (24 hours later), they are collectively burning 10mcm an hour. If the Gas System should suffer a significant supply loss resulting in a deficit of 120mcm at the start of the gas day, the GSO could request all 10 consumers reduce their rate by half or ask 5 of the industrial consumers to cease taking gas completely.

Example B: Load shedding numerous small sites takes much longer than load shedding a few large sites. The speed of load shedding is critical, for example, load shedding delivered 6 hours into the gas day would require 30% more load to be shed than if the reduction occurred at the start of the day. See example below.

If there is a 60 mcm deficit at the start of the gas day and the load is shed immediately, the system is balanced. If load shedding takes 6 hours sites will have used a quarter of their daily demand. Isolating the same sites 6 hours into the gas day will only deliver a 45 mcm load reduction. Additional load shedding will be needed to deliver the 15 mcm already consumed. This 15 mcm will need to be delivered over the remaining 18 hours of the day so would need to be equivalent to 20 mcm start of day load. So, if the load reduction was achieved by isolation large loads of 5 mcm each end of day, 12 would be needed to achieve system balance if isolated at the start of the day compared to 16 sites 6 hours later.

If supply is lost early in the day, there is a reasonable chance that demand can be curtailed to meet the deficit. The later in the day the supply loss occurs the more difficult it is to rebalance the system.

Add to this case study that the GSO is obligated to incentivise the market to solve any supply deficit before moving to the emergency tool kit, and it becomes clear that issuing an instruction to load shed without delay is imperative to prevent the emergency strategy progressing further into the emergency tool kit and putting domestic consumers at risk of losing supply.

It is important to note that a high proportion of embedded generation is not daily metered. Therefore, the GDNs would not know how much is online at the start of the emergency. There is a risk that additional embedded generation load could come online as a result of NTS connected generation being load shed. This would increase GDN demand as they are load shedding their large loads. This could result in the GDNs not achieving their demand reductions in the required timescale pushing the system further into an emergency and the requirement for more load shedding/isolation.

Electricity considerations

Large electricity transmission-connected gas generators are currently required to provide both essential capacity and the services required to operate a power system. The gas generators, along with other fuel types currently provide:

- Restoration services (required to restore the system in the event of a blackout).
- Stability services (required to ensure sufficient inertia is synchronised to manage disturbances).
- Voltage services (required to maintain system voltages within licence standards).

The gas power stations connected to the NTS make up a significant proportion of contracted restoration service providers (>70%). All of them provide stability and voltage services – the requirement for which will vary dynamically depending on system conditions.

It is important to note that there are regional requirements that have to be satisfied for both restoration & voltage services, and there is a national requirement to be satisfied for stability services. Currently a large proportion of these services are provided by large electricity transmission-connected gas generators.

The direction of travel for the electricity industry is for more decarbonisation and diversification, coupled with ESO’s ambition to be able to operate the electricity system with zero carbon by 2025. This will mean that going forwards operability services will have to come from a diverse range of zero carbon technologies offered from electricity transmission and distribution-connected energy resources. As these resources tend to be smaller in capacity and more distributed-connected, there will be greater numbers and system operations will be more complex – ESO & DNOs/DSOs will need to operate as a ‘whole system’.

Real world examples:

- A NGSE has never been declared meaning there is no real-world data on the impact of the loss of NTS generation on the behaviour of embedded generation.

Real world considerations:

- Load shedding NTS connected generators first in the hierarchy (the current approach) could lead to a reduction in electricity system stability and restoration capability because NTS connected generators provide a large proportion of the electricity system's stability, voltage and restoration services.
- Load shedding NTS connected generators first in the hierarchy (the current approach) could lead to generators embedded in the LDZs, not incentivised by NTS pre-emergency demand reduction tools and not of a large enough annual demand to fall into the Stage 2 load shedding hierarchy, to increase generation to meet the deficit left by the reduction in demand from the larger NTS connected generators. This could lead to a net decrease in demand saved.
- Changing the hierarchy to target smaller embedded generators could significantly increase the response times for load shedding and risk not achieving the required saving in the time available.

Exercised examples:

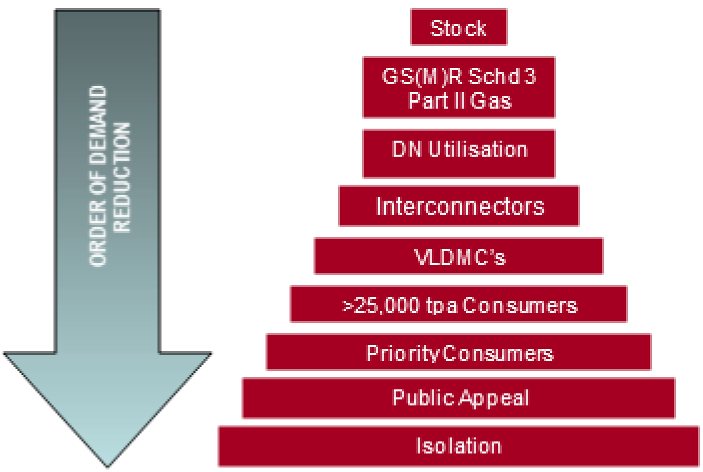
Exercise Baltic (2020): Exercise Baltic (2020): Exercise Baltic tested the efficiency of the load shedding protocol on the National Transmission system. 94% of sites confirmed that when contacted they would cease taking gas within 1 hour.

Similar assurance was sought from the GDNs in their ability to contact their top 50 sites in each LDZ (COVID-19 restrictions reduced this from the normal requirement to test the ability to contact the top 200 sites per each LDZ). 600 sites were contacted and 572 (90%) confirmed they would cease taking gas within 2 hours.

If the load shedding hierarchy were to be altered, there is a risk the efficiency experienced in Exercise Baltic would be reduced as more sites would require to be contacted, some of which currently have no obligation to provide contact details.

Factual Information:

T/PM/E1 is the management procedure used for managing a Network Gas Supply Emergency prepared in accordance with the Network Emergency Coordinator's Safety Case. Section 10 of this document sets out the hierarchy for load shedding on the Gas network. This is illustrated in Figure 5, which is included below.



Stakeholder Support:
• The gas system is currently favoured over the electricity system. This is correct from a safety perspective but there are huge impacts to a loss of electricity supplies. • Gas supply shortages constitute an energy emergency, not just a Network Gas Supply Emergency.
• The gas priority customer list would benefit from review and there are opportunities to better align it to the electricity priority site list. • There are challenges in the quality of priority customer data which is provided to the GDNs by Gas Shippers.
• Load shedding currently removes large generators first which is detrimental to electricity system stability.

Opportunity 6

Opportunity Statement:

There is a lack of whole energy system coordination to the issuing of warning notices and pre-emergency market incentive tools. Industry behaviour may therefore be unsupportive of the maintenance of whole energy system health.

Background:

Stakeholder feedback shows that business decisions are dominated by commercial drivers, which may reduce the effectiveness of measures such as network warning notices and pre-emergency market incentive tools.

In times of whole system stress there is a risk that inflated prices in one market lead to a lack of industry action to support whole energy system health.

Impact (project team view):

Industry decision making is dominated by commercial drivers until a point of legal instruction by either energy network. Without early whole system coordination there is increased risk that industry may worsen whole system health rather than play a role in supporting it. This may result in increased costs to consumers through one or both fuels needing to take increased commercial or physical action to resolve the situation, and in the worst case this may result in demand control measures being taken by one system simultaneously to the other system being in a comfortable position. This could be described as a disparity between systems supporting whole system health.

Early and coordinated issue of energy system warning notices should theoretically ensure that industry support whole system health at an earlier point in time, increasing the likelihood that demand control measures may be averted. There is also the opportunity to consider specialist forms of notice relevant to a whole system response to a gas supply shortage, for example a framework could be introduced which favours non gas generation upturn when gas supplies are low.

Real world examples:

- **Beast from the East 1st March 2018 -** The last real-world activation of the pre-emergency suite of tools on the Gas Network occurred on 1st March 2018 and saw the use of Operating Margins and activation of a National Off-Peak Exit Capacity Scale-Back.
  - The utilising of **Operating Margins** saw the contractual instruction of one power station to reduce their consumption of gas, which they complied with.
  - Activation of a **National Off-Peak Exit Capacity Scale-Back** saw all power stations comply, with none overrunning from their agreed firm capacity volume.

  On this day the Electricity Network was not in parallel stress and was being supplied by a diverse mix of fuel types, therefore less reliance on gas fired generation during the gas day (gas generation represented 23% of the overall generation mix).

  There have been no other significant supply shortage stress events on the Gas Network in recent history (since 2013), and therefore no relevant circumstance where these tools have been activated "real-world". Because of this there is no data available to determine the behaviour of NTS connected generation when being incentivised to reduce gas demand in parallel to the electricity market providing incentive to generate power.

- **Gas Network Capacity Over-Runs** Further investigation is required to understand whether any relationships exist between compliance with gas network pre-emergency measures and electricity system warning notices. It is recommended that option development also examine the link between compliance with pre-emergency measure on the gas network and electricity market prices.

Real world considerations:

- **Constraint management tools** used by either network impacting the other network - Constraint management tools have been utilised by the GNCC 5 times within 2020 and 7 times within 2021. These occasions constitute times of potential elevated risk for the electricity network depending on the active generation mix at that time. These decisions are taken by the GNCC without any knowledge of the potential strain that may occur within the ENCC. It is possible that the use of these tools will result in flexible electricity generators becoming inflexible at high power output levels in the Electricity Balancing mechanism. This may result in cost/security issues in low demand periods when the ESO requires flexibility to reduce power output levels from these generators. To manage this situation the ESO may incur higher costs than is necessary or be required to issue Grid Code warnings and take Emergency action.

- If the Electricity System's generation mix on 1st March 2018 had gas as the majority generation source, stakeholder engagement suggests that generators would have favoured the electricity market conditions over the gas incentives to reduce demand. If an electricity Capacity Market Notice (CMN) had been activated this would have introduced the potential for some generators to be at risk of significant penalties had they failed to generate. This financial consideration may cause generators to withdraw from gas Operating Margins services and overrun their capacity bookings, despite this meaning a breach of contract.

  To illustrate this risk further, table 2 documents the average gas exit capacity overrun penalty across the Gas winter 20/21 for NTS power station connections.

  Table 2 – Average overrun penalty charge Gas Winter 20/21 (only charges above £1000 included)

Average over-run penalty Gas Winter 20/21
£2,948

- Comparatively, Electricity Capacity Market obligations also carry penalties for unavailability. Failure to deliver Capacity Market obligations in one Settlement Period that is deemed to be a System Stress event will lead to a penalty equivalent to 1/24th of the Capacity Market Provider's annual payment. Table 3 documents the likely penalties associated with failure to deliver electricity generation in a system stress event.

Table 3 – Electricity Capacity Market Obligations – Penalty Charges

Taking the latest Capacity Market auction for 2024/25 t-4 as an example:
• Clearing price = £18/kW/year. • Capacity 760MW for a typical Combined Cycle Gas Turbine (CCGT) electricity generator. • CCGT de-rating factor of 90% applied. • De-rated capacity = 684MW. • Annual payment = £12,312,000 • 1/24th (or penalty per Settlement Period) = £513,000

- If the Capacity Market Provider in the example in table 4 were to be instructed off for 12 hours or more during a period when a Capacity Market Notice is active and a System Stress Event is subsequently declared, the Capacity Market Provider would be obliged to pay back its total annual Capacity Market revenue of **£12.3 million**. This represents massive financial risk to Capacity Market Providers, far exceeding liabilities against Gas contracts and incentives.

Exercised examples:

Exercise Baltic (2020): Exercise Baltic simulated all Operating Margin contracts being honoured and fully effective and, the scale-back of off-peak exit capacity being fully complied with. If electricity market considerations had been simulated in the exercise the actions taken by the GSO to incentivise the reduction in industrial demand on the NTS would likely have been countered by the ESO issuing electricity system warning notices. This would likely have reduced the effectiveness of the demand reduction incentives issued in the pre-emergency phase. Whilst this would likely have reduced the severity of the demand control measures taken by the ESO, resulting in 7 million electricity consumers losing their supply in the short term, it would likely have required the NEC to declare an NGSE earlier than simulated.

Factual Information:

Electricity Capacity Market Rules

The electricity Capacity Market rules section 8.5.1 describes Discharging a Capacity Obligation: -

8.5.1 Response to a Capacity Market Notice
During a System Stress Event, a Capacity Provider must deliver the Adjusted Load Following Capacity Obligation of its Capacity Committed CMU, provided that a Capacity Provider has no obligation, pursuant to this Rule 8.5.1:
(a) unless a Capacity Market Notice has been issued with respect to the System Stress Event and the System Stress Event falls four or more hours after the expiry of the Settlement Period in which the Capacity Market Notice is published on the website of the System Operator;
(b) in any Settlement Period during which the Capacity Committed CMU is affected by a suspension under section G (Contingencies) of the Balancing and Settlement Code; or
(ba) where the Capacity Committed CMU is an Interconnector CMU, in any Settlement Period during which the CMU is affected by a measure taken by the System Operator which has the effect of reducing the Net Output of that CMU to an amount lower than the Interconnector Scheduled Transfer; or
(c) in any Settlement Period during which the Capacity Committed CMU is affected by a "relevant interruption" pursuant to section 5.10 of the CUSC and in each of the eight Settlement Periods falling after the Settlement Period in which the relevant interruption ceases to affect the Capacity Committed CMU;
or

(d) in any Settlement Period during which the Capacity Committed CMU is bound to comply with a direction issued by the Secretary of State pursuant to section 34 of EA 1989 and in each of the eight Settlement Periods falling after the Settlement Period in which the direction ceases to affect the Capacity Committed CMU.

The Gas Safety Management Regulations state that 'a person conveying gas in a network may direct a person not to consume gas for the period specified in the direction' or face criminal proceedings led by the Health and Safety Executive, the competent authority of GS(M)R. The relevant sections of GS(M)R and T/PM/E1 Procedure for Network Gas Supply Emergency are included below for reference.

Gas Operating Margins - Obligations

National Grid Gas purchases Operating Margins (OM) annually, in line with both the requirements of TPD Section K of the Uniform Network Code (UNC) and obligations described in the National Grid Gas Safety Case in respect of the National Transmission System. The Safety Case places an obligation on National Grid Gas to maintain OM at levels and locations determined throughout the year.

The OM service is used to maintain system pressures in the period before other system management services become effective (e.g. national or locational balancing actions). Primarily, OM will be used in the immediate period following the occurrence of any of the following, if all other system operator actions are insufficient:

- supply loss: terminal, sub-terminal, interconnector, LNG importation terminal;
- pipe break (including loss of infrastructure that renders pipe unusable)
- compressor failure; or
- demand forecast error.

A further quantity of OM is also procured to manage the orderly run-down of the system in the event of a network gas supply emergency (NGSE) while firm load shedding takes place.

OM gas can be provided by a number of operators under current arrangements:

- Storage facility operators
- Primary capacity holders at storage facilities
- LNG importation (with storage) facility operators
- Primary capacity holders at LNG importation facilities with storage
- Power Station operators (CCGTs) who can reduce demand from the NTS

Gas Capacity

Exit capacity gives shippers the right to take off the National Transmission System (NTS). Capacity is often also referred to as 'rights' or 'entitlements'. A shipper needs to buy one unit of capacity in order to flow one unit of energy. This is known as the 'ticket to ride' principle. Units for both capacity and energy are in kWh/day.

Capacity is available to the market at each NTS exit (offtake) point as:

- Firm The volume of firm capacity made available at each offtake point consists of the following amounts:
  - baseline exit capacity (obligated) – as defined by NG's Gas Transporter Licence;
  - incremental exit capacity (obligated) – firm capacity made available over and above baseline, in response to market demand and supported by user commitment. This increase in capacity is permanent; and
  - incremental exit capacity (non-obligated) – NG can release additional firm capacity at an offtake point over and above obligated levels.
- Off-Peak. Off-peak capacity can be made available to the market at offtake points where firm capacity is not being used. The volume of off-peak capacity available at an offtake consists of three parts:

- use it or loseit (UIOLI) – any firm capacity that hasn't been used over recent days can be resold to the market as interruptible capacity;
- unutilised maximum network exit point offtake rate (MNEPOR) – during D-1 at 13:30 the NTS demand forecast is published. Where this demand forecast is less than 80% of the annual peak 1 in 20 demand forecast, NG are obliged to release any remaining capacity up to the MNEPOR level as off-peak capacity; and
- discretionary – NG can make additional off-peak capacity available to the market.

If there are low pressures on the network, NG may curtail off-peak capacity rights, without any compensation for the users affected. i.e. A National Scale-Back of Off-Peak Exit Capacity

If a user's flow exceeds their capacity entitlements for any given gas day, a shipper will incur an overrun charge. The overrun charge is the shipper's financial incentive to buy all the capacity that it needs. More information relating to overruns can be found in Uniform Network Code Transportation Principal Document - Section B3.13, System Use & Capacity.

Stakeholder Support:	
Both fuels having different balancing approaches leads to difficulty in interpreting pre-emergency incentives	The current design of the markets will lead to the two commodity prices chasing each other until one system is required to take directive action.
• Warning notices need to carry financial incentive • The issue of Gas warning notices is rare which leads to unfamiliarity in how to respond • Our trading position tends to be locked in day ahead. Decision making is driven by economics. • Desire to support whole system health, but lack of transparency and clarify of information makes this challenging.	
• Decision making is dominated by the balance of financial reward and penalties, across both gas and electricity markets, until legally instructed to behave differently • Economics are closely watched between markets, with commercial teams often sat closely together and analysing market interplay. • Industry is more familiar with the issue of electricity warning notices in comparison to issue of gas warning notices. • Commitments are often made day ahead, resulting in challenges for industry to respond within day due to contract penalty charges.	

Opportunity 7

Opportunity Statement:

There is currently no force majeure clause in electricity capacity contracts to cover when generators are load shed under a Network Gas Supply Emergency (NGSE).

Background:

Electricity generators have raised concerns that under current electricity Capacity Market contracts they could be financially penalised for responding to a gas load shedding instruction, which is a legal requirement. This observation is inconsistent with whole energy system thinking.

Impact (project team view):

Large gas-fuelled electricity generators may have Capacity Market contracts in place. If they do, and a Capacity Market Notice has been issued, during a System Stress Event they will have to deliver their Capacity Market obligation or they will face penalties.

A System Stress Event is not formally declared until post event and relates to electricity demand shedding initiated by either formal ESO instruction or automatic Low Frequency Demand Disconnection schemes. The demand shedding instruction should be for a period greater than 15 minutes.

A Capacity Market Notice is a notice to the electricity market, issued 4 hours ahead of real time. It is given when the expectation of a System Stress Event is higher than a set threshold. The Capacity Market Notice website (owned by ESO) calculates the electricity system margin (using a pre-set formula) for every Settlement Period (½ hour) and automatically posts a Capacity Market Notice when the electricity system margin dips below the threshold. It is a settlement tool that electricity market participants can subscribe to.

Failure to deliver Capacity Market obligations in one Settlement Period that is deemed to be a System Stress event will lead to a penalty equivalent to 1/24th of the Capacity Market Provider's annual payment.

Taking the latest Capacity Market auction for 2024/25 t-4 as an example, the following is estimated: -

- Clearing price = £18/kW/year.
- Capacity 760MW for a typical Combined Cycle Gas Turbine (CCGT) electricity generator.
- CCGT de-rating factor of 90% applied.
- De-rated capacity = 684MW.
- Annual payment = £12,312,000
- 1/24th (or penalty per Settlement Period) = £513,000

If the Capacity Market Provider in the example above is instructed off for 12 hours or more during a period when a Capacity Market Notice is active and a System Stress Event is subsequently declared, the Capacity Market Provider will be obliged to pay back its total annual Capacity Market revenue of £12.3 million. This represents massive financial risk to Capacity Market Providers.

Capacity Market Providers are exempt from penalties if they are providing "Relevant Balancing Services" during a System Stress Event. These are defined as Short Term Operating Reserve, Fast Reserve, Enhanced Frequency Response, Firm Frequency Response, Constraint Management Service and Frequency Control by Demand Management.

For Gas Fired Generation directly connected to the Gas National Transmission System, Capacity Market Contracts represent a conflict in direction. Any hesitation to comply with the legal load shedding instruction (GS(M)R) to cease taking gas represents a loss of supply.

Real world examples:

- Since 1st October 2016 5 Capacity Market Notices have been issued. 2 were issued in 2016 and the remaining 3 between September 2020 and January 2021.
- No System Stress Events (which would have meant the application of penalties for non-delivery to Capacity Market Providers) have occurred.

Real world considerations:

- The activation of a Capacity Market Notice in parallel to the issue of directions to cease taking gas by the GSO (under the authority of the NEC) could lead to:
  - a hesitation to comply with the legal gas instruction to cease taking gas
  - significant punitive costs to generators which they are unable take action to avoid.

Exercised examples:

Exercise Baltic (2020): Exercise Baltic did not test the activation of an Electricity Capacity Market Notice against the pre-emergency and emergency framework being simulated on the Gas System.

Factual Information:

The electricity Capacity Market rules section 8.5.1 describes Discharging a Capacity Obligation: -

8.5.1 Response to a Capacity Market Notice
During a System Stress Event, a Capacity Provider must deliver the Adjusted Load Following Capacity Obligation of its Capacity Committed CMU, provided that a Capacity Provider has no obligation, pursuant to this Rule 8.5.1:
(a) unless a Capacity Market Notice has been issued with respect to the System Stress Event and the System Stress Event falls four or more hours after the expiry of the Settlement Period in which the Capacity Market Notice is published on the website of the System Operator;
(b) in any Settlement Period during which the Capacity Committed CMU is affected by a suspension under section G (Contingencies) of the Balancing and Settlement Code; or
(ba) where the Capacity Committed CMU is an Interconnector CMU, in any Settlement Period during which the CMU is affected by a measure taken by the System Operator which has the effect of reducing the Net Output of that CMU to an amount lower than the Interconnector Scheduled Transfer; or
(c) in any Settlement Period during which the Capacity Committed CMU is affected by a "relevant interruption" pursuant to section 5.10 of the CUSC and in each of the eight Settlement Periods falling after the Settlement Period in which the relevant interruption ceases to affect the Capacity Committed CMU;
or
(d) in any Settlement Period during which the Capacity Committed CMU is bound to comply with a direction issued by the Secretary of State pursuant to section 34 of EA 1989 and in each of the eight Settlement Periods falling after the Settlement Period in which the direction ceases to affect the Capacity Committed CMU.

The Gas Safety Management Regulations state that 'a person conveying gas in a network may direct a person not to consume gas for the period specified in the direction' or face criminal proceedings led by the Health and Safety Executive, the competent authority of GS(M)R. The relevant sections of GS(M)R and T/PM/E1 Procedure for Network Gas Supply Emergency are included below for reference.

The Gas Safety (Management) Regulations (GS(M)R), require that:
Co-operation
6. (1) Every person to whom this paragraph [Co-operation 6-(1)] applies shall co-operate so far as is necessary with a person conveying gas in a network and with a network emergency co-ordinator to enable them to comply with the provisions of these Regulations.
(2) Paragraph (1) applies to—

(a) a person conveying gas in the network;
(b) an emergency service provider;
(c) the network emergency co-ordinator in relation to a person conveying gas;
(d) a person conveying gas in pipes which are not part of a network by virtue of regulation 2(3) or (4);
(e)the holder of a licence issued under section 7A of the Gas Act 1986(3);
(f) a person exempted under section 6A(1) of the Gas Act 1986(4) from paragraph (b) or (c) of section 5(1) of that Act;
(g) a person referred to in paragraph 5(1) of Schedule 2A to the Gas Act 1986;
(h) the person in control of a gas production facility, a gas processing facility, a storage facility or an interconnector supplying gas to the network.

Further:
<u>(4) A person conveying gas in a network may, subject to paragraph (5), direct a person not to consume gas for the period specified in the direction.</u>

(5) A direction under paragraph (4) may—

(a) only be given where it is necessary to prevent a supply emergency or to prevent danger arising from the use of gas not conforming with the requirements of regulation 8;
(b) be given orally or in writing and may be withdrawn at any time.

(6) Where a direction is given to a person pursuant to paragraph (4), that person shall comply with it during the period specified in the direction except that this shall not require him to comply with a direction after it has been withdrawn.

T/PM/E1 Procedure for Network Gas Supply Emergency states that:

Load shedding is the procedure used by transporters to secure a graduated and controlled reduction in demand on all or part of their systems in order to keep the system securely pressurised.

The Primary Transporter will identify, in the emergency strategy, the volume and location of the load shedding required. If the emergency strategy identifies the need for load shedding in a secondary system, the Primary Transporter will communicate with the relevant gas transporter the volume to be shed. It is the responsibility of the relevant gas transporter to maintain a supply-demand balance in their part of the network. In the event that the Primary Transporter requests load shedding in a secondary system it is the responsibility of the secondary transporter to ensure this is implemented.

The Primary Transporter must determine the actual effect of the measures by continuously monitoring the offtake of gas from the Primary System and updating the NEC. If the supply-demand imbalance is deteriorating, the Primary Transporter in consultation with the NEC must revise the emergency strategy and increase the quantity of load shedding or it should request the NEC to escalate the NGSE to stage 3.

Stakeholder Support:	
Generators supporting gas incentives to reduce, or cease taking gas, will likely be charged for non-delivery in electricity markets.	There should be a force majeure clause in the capacity market contracts to cover generators load shed during an NGSE
Commitments are often made day ahead, resulting in challenges for industry to respond within day due to contract penalty charges.	

Opportunity 8

Opportunity Statement:
The instruction to Load shed sites which rely on heat to maintain machinery/product is overly damaging to industrial sites.

Background:
Stakeholder feedback gained from major energy users highlighted a preference to maintaining some level of energy consumption (e.g. baseload) with a notice period rather than full disconnection at short notice. This would enable businesses to maintain some level of operation and reduce the level of disruption experienced. There is a risk that total disconnection may see some businesses experience significant and/or unrecoverable financial and operational damage. The current load shedding hierarchy is designed to be as efficient as possible by instructing the largest loads to completely cease taking gas as soon as practical.

Impact (project team view):
The direction to cease taking gas at Stage 2 of a Network Gas Supply Emergency (NGSE) has been cited as impactful to many industrial gas consumers. Already built into the gas load shedding hierarchy is the assignment of priority customer status, to consumers for whom a loss of gas supply constitutes of threat to life (category A), or, financial losses in excess of £50 million (category C). For industrial activities associated with the use of heat to liquidise a material, the loss of gas supply can be especially damaging. In this circumstance the liquid product may solidify in the plant leading to significant corrective maintenance costs and the loss of raw materials or partly produced products. Absent from the current understanding of this issue is data associated with these costs. Though these costs do not reach the category C priority customer threshold, beyond sites already listed as category C, they are, as a collective at least, assessed to be in the bracket of millions of pounds worth of losses. The sourcing of such levels of data is a large-scale activity which, it is recommended, should be considered by the proposed options. Further, an understanding of the quantities of gas consumption required to maintain ‘base load’, is also a detailed data collection exercise which should also be considered by the option statements, versus conducting any pre-work in this area. The counter consideration to this issue is the resultant requirement to source demand savings, which would have been achieved through load shedding, further into the emergency framework. It is recommended that option statements should avoid favouring any form of industrial load over domestic consumer demand. Instead the option statements should look to determine how a wider cross section of industrial consumers are asked to reduce their demand to ‘base load’, thereby sharing the disruption that this action causes beyond NTS connected sites, whilst limiting the financial impact of a complete loss of supply. Finally, it should not be overlooked that some industrial consumers have mitigated their risk to a loss of supply through the adoption of alternate fuel sources. These back-up arrangements are designed to provide a base load if the primary fuel source is lost. There is a potential counter impact to alternative fuel supply chains, such as fuel oil and red diesel, should a large number of industrial customers look to bolster their standby stocks during a long duration gas supply interruption. An instruction to reduce to a baseload level will reduce the effectiveness and timeframe over which demand saving is achieved.

Real world examples:

- An NGSE has never been declared meaning there is no real-world data on the impact of a loss of gas for heat for industrial consumers.

Real world considerations:

- Any change to the load shedding hierarchy which reduces the demand savings it can achieve and the pace at which it can be delivered, leads to the risk that load shedding is not quick enough at reducing sufficient levels of demand. This could lead to Stage 3 isolation being required earlier in the response.

Exercised examples:

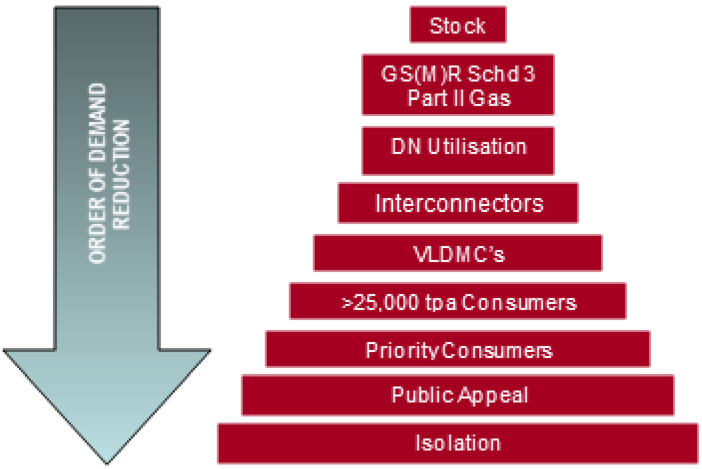
Exercise Baltic (2020): Exercise Baltic tested the efficiency of the load shedding protocol on the National Transmission system. 94% of sites confirmed that when contacted they would cease taking gas within 1 hour.

Similar assurance was sought from the GDNs in their ability to contact their top 50 sites in each LDZ (COVID-19 restrictions reduced this from the normal requirement to test the ability to contact the top 200 sites per each LDZ). 600 sites were contacted and 572 (90%) confirmed they would cease taking gas within 2 hours.

As a test of the current load shedding hierarchy, the exercise did not seek any form of reduction to base load, nor gather any data on the impact to sites which use gas to maintain heat to maintain machinery/product.

Factual Information:

T/PM/E1 is the management procedure used for managing a Network Gas Supply Emergency prepared in accordance with the Network Emergency Coordinator's Safety Case. Section 10 of this document sets out the hierarchy for load shedding on the Gas network. This is illustrated in Figure 5, which is included below.



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<table>
<tr><th colspan="2">Stakeholder Support:</th></tr>
<tr><td colspan="2">• Preference to turn down energy consumption to an agreed baseload level rather than completely be turned off.
• Significant reliance on gas supply to operate plant. Risk of some businesses experiencing unrecoverable disruption in the event of a gas supply loss.
• A requirement to better understand which users fall under essential service classification, on both systems.</td></tr>
<tr><td colspan="2">It is very impactful to completely lose energy supplies, but we have made efforts to increase the resilience of our plant through back up generation. Preference is to be turned down and not off, with as much notice as possible.</td></tr>
<tr><td>If load shedding is ever required it is vital that is delivered at pace to avert the latter and more impactful stage of isolation being required</td><td>A complete loss of energy supplies can be hugely detrimental to major energy users, not just in lost production time/revenue but in serious damage to plant. Turn down rather than turn off requested.</td></tr>
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