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To all interested parties,

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Dear Colleagues,

Joint response to the feedback on proposed changes to the Entry Capacity Release (ECR) Methodology Statement

Thank you for submitting your feedback to the consultation. We received 9 responses to our proposal (1 in support, 7 opposed and 1 provided comments).

As stressed in the consultation cover letter, the purpose of the consultation was to articulate the risk to the wider industry and to seek views on our proposal[1], as well as to seek potential alternatives regarding the most appropriate ways to mitigate the risk. We would like to thank the industry for both its engagement on these issues and putting forward alternative suggestions. Based on the feedback received, we have decided to modify our proposal full details of which can be found on page 7. Appendix 1 contains all the alternative solutions gathered and we would like to continue to discuss these with the industry as part of our ongoing engagement and shared long term solution development.

Due to the recurrence of some of the comments, as well as insights provided, we've decided to issue one response to the industry in which we will try to address the main concerns raised which are detailed in blue below.

A number of responses stated that the Milford Haven (MH) entry capacity reductions implemented in May 2022 resulted in cargo deliveries being cancelled or diverted due to the uncertainty over entry capacity availability and associated bookings. This was further supported by comments regarding more comprehensive analysis of the impact of less LNG being delivered on the wholesale gas price to be considered against the cost of potential constraint management actions.

As stated in the consultation letter, we recognise that there are two different consumer risks; the potential costs of constraints through the system not being able to transport the full amount of gas delivered through Milford Haven, vs the potential impact on wholesale gas prices if LNG cargoes are diverted away from GB. Therefore, we believe that as these both have different consumer impacts, a decision needs to be taken as to which carries the greater risk.

[1] https://www.nationalgrid.com/gas-transmission/document/141626/download

We still believe that LNG Operators and Shippers are best positioned to articulate the potential impact of a cargo loss on the wholesale gas price and NBP. As stated by one respondent National Grid *is not best placed to carry out the analysis (…). The market fundamentals and hence costs of different solutions are dependent on the costs incurred by Shippers as a result of needing to reschedule or cancel injections at the Entry Point and on the cost of replacing gas from alternative sources. This analysis requires data and knowledge from market activity outside of National Grid's operations.* We agree with that statement. Gas undelivered would be likely to be replenished via alternative supply sources, the price of which will depend on contractual arrangements that Shippers have (or expect to have) with other terminals and producers.

The respondents to the consultation suggested that a number of cargo deliveries had been cancelled or diverted away from the Milford Haven (MH) terminal as a direct impact of the capacity reductions that were approved for summer 2022. Assuming this was a direct cause, these decisions would have been made on the perception of scarcity of capacity, as there was enough unsold capacity and headroom to accommodate additional cargos / flows at MH throughout the summer[2]. We recognise that the diversion of cargoes from GB due the capacity reductions applied is an undesirable outcome when there is sufficient capacity in the network.

One respondent estimated the impact of a capacity reduction on the wholesale price, but not all the assumptions made have been clearly articulated, making it difficult for us to understand this risk compared to the constraint risk. We recognise that there are a number of complex factors that influence LNG deliveries, including global demand, LNG production and sustained high winds (e.g. as seen during January 23) making it very difficult to isolate any one element and draw a direct correlation between the ECR proposals and the impact on LNG deliveries. Nevertheless, we recognise the need for as stable as possible commercial regime in GB for short term and long-term investment and have amended our proposals with this in mind.

It was not and is not our intention to discourage the supply of LNG to the GB where the network capability is able to accommodate it. It was our opinion that releasing forward capacity up to capability levels would offer certainty to the market, whilst reducing the risk to industry and consumer cost of potential constraints. The potential cargo cancellations and/or diversions, insights provided by parties regarding how they plan flows and how they aim to avoid constraints, as well as the unused network capability during summer 2022, have all played a role in our decision to amend our proposal.

Flawed assumptions in cost of constraint analysis.

A number of respondents stated that the assumptions made in the calculation of potential constraint costs were unrealistic, and that using historic data as a proxy to estimate cost of locational sell and buy actions is flawed in the current market conditions. Furthermore, a number of respondents stated that the constraint volume is unlikely to be at levels of 22mcm/d and enduring. The view expressed was that the consultation lays out an extreme picture, and not a realistic view. It was also pointed out that Ofgem has concerns over the approach to the calculation of constraint costs based on a 50/50 split between buybacks and location actions.

We acknowledge that the figures included in the consultation represent a credible worst-case scenario, and that the numbers are a scenario and not a forecast. It is challenging to forecast the costs of managing constraints as the costs of locational trades and capacity buybacks are heavily dependent on day-to-day market conditions and participant behaviour. Furthermore, over the last 12 months gas

[2] See page 1 of the December 2022 ECR Consultation Cover letter https://www.nationalgrid.com/gas-transmission/document/141626/download

prices have been volatile. Individual participants will have different commercial and physical positions and therefore behaviour is difficult to predict, as is the physical impact of any commercial actions undertaken (which would then impact potential further actions).

We have taken the feedback provided in the consultation responses onboard, and in this response have included new scenarios capturing a variety of inputs to demonstrate how the potential constraint costs for a sample day may change based on different assumptions. The scenarios are:

Scenario 1 is our original scenario (included in the consultation letter). In Scenario 2 we have updated locational buy and sell prices, using the average differential from SAP observed on 18th January 2023, when locational actions were taken at MH to manage an entry constraint. This is the most up to date information we have and as such, should reflect the current market conditions (accepting that this was not a summer constraint). This data indicates that bids accepted were sold at the average 61% of SAP on the day (as opposed to the assumption of 76%) and locational buy actions were 45% higher than SAP (as opposed to 37% in the previous calculation). The updated figures added £3m to our calculation of the potential day 1 constraint costs.

Scenarios 3/4/5/6 capture the costs based on the following assumptions:

- We have updated the locational sell and buy prices as per scenario 2
- In addition to 87mcm/d flows, we have utilised flows of 79mcm/d and 71mcm/d to generate different constraint volumes to demonstrate how the costs would change depending on the severity of the constraint
- We have used 350p/th and 173p/th as prices to demonstrate how the costs would change depending on the prevailing price on the day. At the time of issuing our original proposal the gas price was 350p/th. The May 2023 forward gas price as of 23/1/23 is 173p/th.

	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Capability	mcm/d	65	65	65	65	65	65
Flow	mcm/d	87	87	79	79	71	71
Constrained vol	mcm	22	22	14	14	6	6
Gas price	p/th	350	350	350	173	350	173
Locational sell	p/th	266	217	217	107	217	107
Locational buy	p/th	480	511	511	253	511	253
Buy Back	p/th	525	525	525	260	525	260
		Total costs					
Locational Sell (50%)	£	10,982,322	8,959,262	5,701,349	2,818,095	2,443,435	1,207,755
Locational Buy (25%)	£	9,898,540	10,548,809	6,712,878	3,318,080	2,876,948	1,422,034
Buyback (50%)	£	21,675,635	21,675,635	13,793,586	6,817,972	5,911,537	2,921,988
		Total costs					
Day 1 cost	£	20,591,853	23,265,181	14,805,115	7,317,957	6,345,049	3,136,267

*N.B Day 1 cost = (constraint volume * (50/25)%) * locational offer/bid price /100*

As with any analysis that has a number of assumptions and variables, we are aware that there can be many outcomes, and with these elements and the current market conditions, it is very difficult to predict the magnitude of potential costs. Based on the figures detailed above the daily cost could vary between £23m to £3.1m. In an enduring constraint the costs are likely to increase further and the total cost will need to be multiplied by the number of days the constraint lasts, with the increase factor added to the calculation.

A number of respondents thought that buybacks are unlikely to occur considering that National Grid has last utilised buybacks as a constraint management tool in 2006. We have therefore included 4 scenarios (7/8/9/10) which indicate the potential level of costs in instances where locational actions only are executed to manage the constraint i.e. 100% of the constraint volume was covered by locational sell actions (requesting supply turn down at the Milford Haven terminal or demand upturn from gas users in the Milford Haven area). Within these scenarios we have maintained the assumption that half of the constraint quantity would need to be purchased through locational buy trades (in other areas of the network to help maintain the overall network balance).

	Scenario 7	Scenario 8	Scenario 9	Scenario 10
Capability	65	65	65	65
Flow	79	79	71	71
Constrained vol	14	14	6	6
Gas price	350	173	350	173
Locational sell	153	107	153	107
Locational buy	363	253	363	253
Buy Back	-	-	-	-
	Total costs			
Locational Sell(100%)	11,402,698	5,636,191	4,886,870	2,415,510
Locational Buy (50%)	13,425,757	6,647,195	5,753,896	2,848,798
Buyback	-	-	-	-
	Total costs			
Day 1 cost	2,023,059	1,011,004	867,025	433,287

Scenarios 7 and 8 calculate a daily constraint cost on flows of 79mcm, where the constraint volume of 14mcm is sold in locational sell actions at the gas prices of £350p/th and 173p/th. Half of the constraint volume (7mcm) needs to be purchase via locational buy actions. In such scenario the day 1 cost would be £2m and £1m respectively. If the constraint volume decreases (scenarios 9 and 10), so does the daily cost. In the case of an enduring constraint across multiple days and as such, prices may also increase, the total cost of constraint could still be high.

One respondent pointed out that *National Grid have calculated the cost of locational trades by selling more gas than is bought back to maintain integrity of the system. This does not seem to be a correct approach to isolating the costs of constraint management.* To clarify; if a locational sell action further depletes linepack in an already light system, this is likely to lead to a requirement to buy gas elsewhere on the network to maintain the overall system balance. How much of the gas will need to be purchased will depend on the linepack at the time i.e., if the system is heavy, there might not be a need to buy at all, hence we have assumed that we only buy gas on 50% of the days on which we locationally sold.

A number of respondents questioned whether we would use buybacks as a constraint management tool. From the transmission operator perspective this remains an available tool use of which will be dependent upon a number of factors including the level of capacity sold (i.e. calculation of the firm entitled flow rates), as well as severity of a constraint (how high the flows are in comparison to capability, the pressure on the system and the potential duration of the constraint).

It is our understanding that participation in locational constraint actions at MH will be dependent on the level of LNG storage available at the sub-terminals, e.g. if storage space is available, Shippers might have the option of delaying flows, therefore they will be more likely to participate in locational sell actions. However, in some scenarios the contractual arrangement between the terminal and the Shippers might not allow an opportunity to slow down or delay sendout, e.g. in a situation of the potential cargo diversion due to lack of storage in the tanks.

Should the commercial arrangements prevent the Shipper from reducing flows (e.g., there is no available storage at the terminal), we think the Shipper will be less likely to participate in locational actions and therefore eliminate its effectiveness as a constraint management tool. If the flows cannot be reduced through locational actions, the likelihood of buyback increases.

In a prolonged constraint scenario, the likelihood of managing the network via buybacks increases further (as we assume the likelihood of long-term participation in locational actions decreases as parties flexibility is likely to reduce) and potentially becomes more expensive over time. In the case of a within day constraint NGG would also consider the time of the day that the constraint actions are taken (e.g., in a scenario where the volume of sold capacity is 100mcm, flows are 70mcm and capability 60mcm, we anticipate having to buy back the difference between the firm capacity we have sold (100mcm) and the reduced capability (60mcm) – therefore we would be potentially buying back 40mcm. That would then be pro-rated to ensure we buy it for the remainder of the day only). In an enduring constraint this could then translate into having to purchase the full amount of sold capacity at the day ahead stage.

As stated in the responses there is no buyback data since 2006 as such. We have assumed that in a scenario where buybacks are required, they will be priced at 150% of the daily SAP. In our industry engagement on the potential introduction of capacity buyback cap we were told that the level the cap should be set at should try to incorporate all the costs Shippers might have as an outcome of not being able to flow gas. It was suggested that the daily SAP would need to be considered as a minimum.

How are the costs incorporated in charges and reflected in customers' bills

All entry constraint management costs and revenues go through entry capacity neutrality, regardless of whether the costs incurred are within or exceed the Capacity Constraint Management (CCM) cap and collar scheme incentive[3]. In a constraint scenario where we have to take constraint management actions (either Locational trades and/or buybacks) for several days, we may exceed the constraint management incentive collar (post sharing factor) of £5.2m within days. Any costs (post sharing factor) incurred above £5.2m will be passed on to our customers (and ultimately end consumers) via Entry Capacity Neutrality. The costs are split based on entry customer's firm capacity holdings on the day, therefore each Shipper's firm entry capacity holding will determine their associated charges.

We assume that some or all of these costs will be passed on to end consumers, but we have no visibility of the contracts between our customers and consumers / how such costs are dealt with.

National Grid is passing the risk on to gas shippers and end consumers.

As we stated in the May 2022 consultation response the aim of the change proposed is to protect our customers and end consumers from excessive constraint management costs based on unforeseen global events.

Even with a baseline set at the full network capability level, inherent risk remains with National Grid, such as reduced asset availability through planned and unplanned maintenance. Based on an intact network we propose releasing capacity at Milford Haven based on the 6-year median demand values for each month. Over that period there have been a large number of days where capability was lower than what we are proposing to release.

Lastly, should the proposal be implemented in the amended format (please see page 9 onwards), there is an increased risk of higher constraint costs as capacity will be released up to baseline in some summer weekly/monthly auctions. Therefore the risk of flows exceeding network capability will be higher.

Entry Terminals were built on the expectation that baseline is available throughout the year. Implementation of this proposal will reduce investor confidence. How is National Grid going to manage this problem in the long term?

As explained in the previous consultation response, *baselines are set out in our Licence and this defines the level of available firm capacity we should release at each entry point for each gas day. For most Entry Points the baselines are based on the principle that they should closely reflect the maximum theoretical*

[3] Follow the link to find out more about the Capacity Constraint Management Incentive

physical capability of the point under peak conditions, and as such, cannot necessarily be met 365 days of the year. As Milford Haven was a new Entry Point, Shippers provided an investment signal via capacity auctions (and bookings) where capacity was typically booked in the winter periods. This, combined with forecast lower flows (via FES or its forerunner) in the summer, and a Licence requirement for us to be economic and efficient, led to greater winter capability.

To improve summer network capability, investment in physical network development would be required. The summer risk at Milford Haven was not considered during the RIIO2 price control discussions between Ofgem and National Grid. At that time, the overall perception of risk on the network was low and constraints relatively rare. The war in Ukraine and consequential energy crises has changed the risks. GB has become a transit point for EU gas which has altered the risk profile on the network and significantly increased summer network operation. Without such geopolitical factors, we could have continued using the existing Constraint Management Tools to manage the network safely and effectively.

The current regime requires us to receive an incremental capacity signal to be able to consider additional network investment. The signal enables us to secure suitable investment funding and by providing physical reinforcement, increase our baselines. In order to improve summer capability at Milford Haven and invest in physical network, we would need to receive an incremental capacity signal applicable to summer months via a long term auction or a PARCA application.

We acknowledge that in the current geopolitical circumstances the regime is failing to reflect the lower summer capability issue. In the last couple of months, we have discussed the possibility of introduction of seasonal baselines as a potential solution. We understand that the industry views on this vary. We intend to take the consideration of seasonal baselines forward into RIIO3 deliberations. At the same time, we recognise that RIIO3 outcomes won't be known until 2026, and that any physical investment take years to deliver.

Milford Haven terminals are being put at a competitive disadvantage compared to the Isle of Grain sub-terminal if the proposal is implemented. Summer 2022 was the first summer period for which NGG has not published lower capability at the Isle of Grain (IoG) Entry Point since 2016.

As we will again potentially see increased LNG flows in summer 2023 to help meet EU storage requirements, there is a likely increase in flows at Isle of Grain as well. An increase in flows at the Isle of Grain (or any other entry point), does increase the constraint risk, but the risk is considered within the normal operational management of the network.

The average Isle of Grain flows we have seen in the summer 2022 (May – Sep) were 5.6mcm/d, therefore we think there is an extremely low likelihood of constraint and therefore applying the change to Isle of Grain would have limited benefit and put unnecessary restrictions on NTS Users. Furthermore, the difference between the IoG baseline (65mcm) and average summer capability is much smaller in comparison to MH. Should constraints materialise, we anticipate the constraint volume would be smaller, therefore the potential cost of constraint actions reduced in comparison to Milford Haven.

Our summer 2022 maintenance plan has not published lower capability for the Isle of Grain based on the fact that capability was not impacted by the maintenance carried out.

We cannot comment on the competitive disadvantage of Milford Haven terminal compared to the Isle of Grain. The cargo arrangements are subject to commercial agreements between the terminals and its shippers, which we are not privy to.

Regulatory inconsistencies within and across National Grid's licence, the UNC and methodology statement have been mentioned and the need to address these in the future. There is no opportunity for parties to raise alternate solutions.

We agree that there are complexities in relation to the wording of rules concerning capacity release across different legal documents binding the topic. We are keen to work with the industry on any identified inconsistencies to ensure more clarity is provided where needed. Although the industry cannot directly raise alternative solutions, we are nevertheless obliged to maintain methodology statements (including ECR) and consult and consider our customer and stakeholder views whenever changes to the methodologies are proposed. Furthermore, any responses shared with us as a part of the methodology consultation process are shared with the Authority who reviews whether views expressed in consultation responses have been appropriately assessed and considered.

Outside of the formal consultation process applied where National Grid initiates changes, we would also welcome any comments regarding the methodology content and would work with the industry to conclude whether any amendments to the methodology would be necessary. Consideration of such would require assessment of whether the suggested change would be consistent with the capacity-related objectives as set out in Special Condition 9.17.9 of our Licence.

NGG's proposal

Our original proposal, if approved, would have restricted the release of capacity at the Milford Haven ASEP in the period between 1st May – 30th September 2023. This would have aligned with the timeframes of scheduled Gassco maintenance when GB gas supply will be reduced. The Norwegian maintenance, as published on Gassco's website[4], will affect flows to St Fergus in summer 2023 as follows:

Affected Asset	Type	Event Start	Event Stop	Unit	Technical Capacity	Available Capacity	Unavailable Capacity	Reason
St Fergus	Planned	25/05/2023	01/07/2023	mcm/d	30.8	5	25.8	Yearly maintenance
St Fergus	Planned	01/07/2023	29/09/2023	mcm/d	31.2	0	31.2	Yearly maintenance

While the Technical Capacity available to flow to St.Fergus is 30.8mcm/d or 31.2mcm/d, during summer 2022 we saw a maximum of 6.4mcm/d delivered through St. Fergus (Vesterled pipeline) according to the Gassco website[5]. In summer 2021 the maximum flows reached 27mcm but averaged 3-4mcm/day.

The Gassco outages that have the potential to impact Easington flows are:

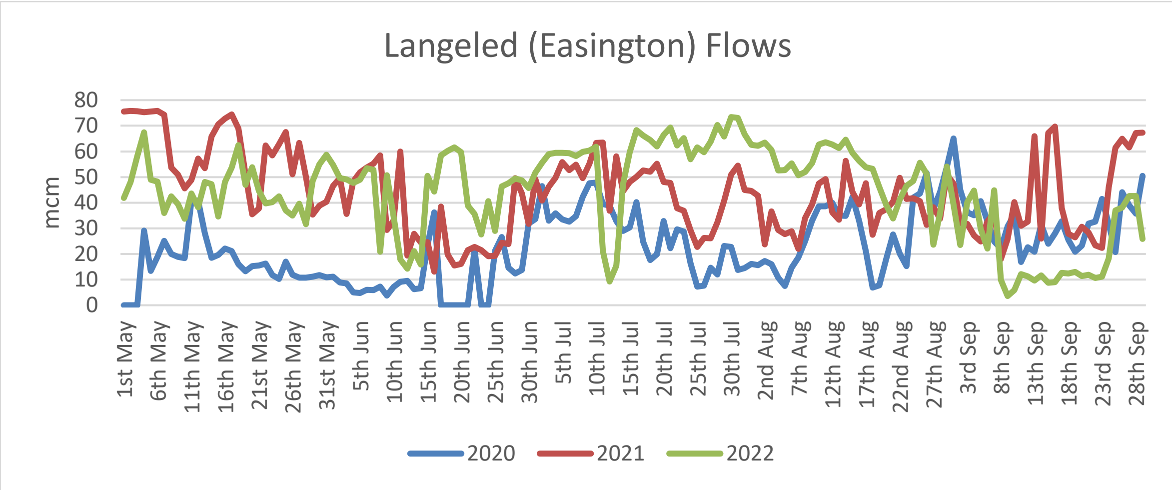
Affected Asset	Type	Event Start	Event Stop	Unit	Technical Capacity	Available Capacity	Unavailable Capacity	Reason
Nyhamna	Planned	19/05/2023	09/06/2023	mcm/d	79.8	0	79.8	Yearly maintenance
Kollsnes	Planned	26/08/2023	07/09/2023	mcm/d	146.5	0	146.5	Yearly maintenance

Under the working assumption that EU gas prices will be higher than GB prices during summer 2023, we expect these outages to result in a significant to total reduction in Easington gas supplies from Norway.

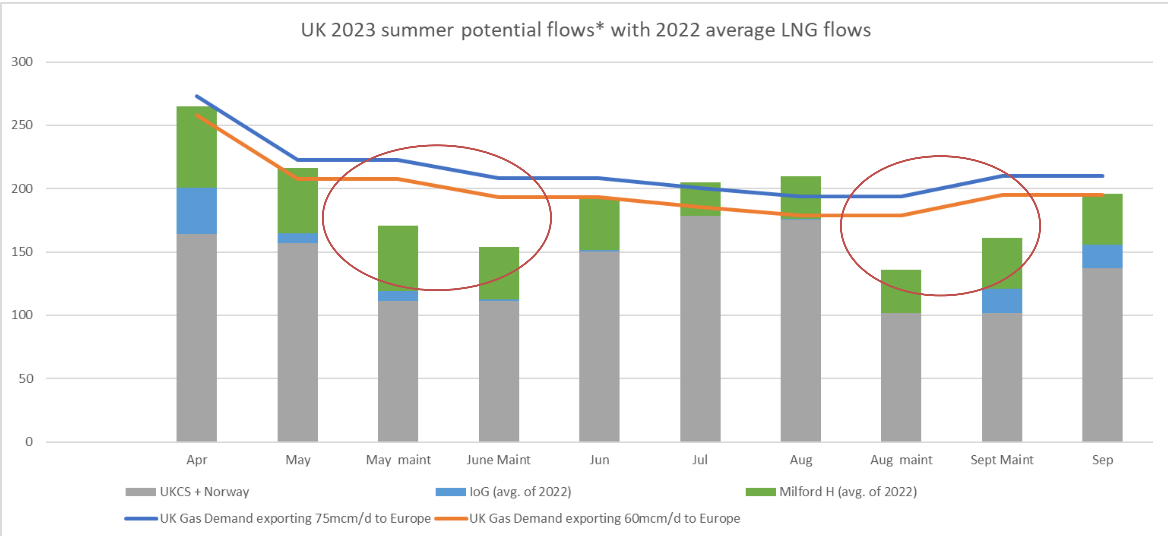
[4] Gassco maintenance
[5] https://umm.gassco.no/ch/

The higher EU gas prices typically seen in summer months mean that the remaining Norwegian gas flows will be directed to Europe, and not GB.

As shown below the Langeled flows delivered to Easington have been consistently high in the last 3 years in the summer period. Last year, the flows averaged 44mcm/day with the highest flow being 70mcm/day. This compares to 43mcm/day average flows in 2021 and a 75mcm/day highest flow.



The chart below shows the expected average GB demand based on exporting either 60mcm/d or 75mcm/d to Europe, against the expected supply based on the average monthly flow of LNG in 2022 and the expected impact from the Gassco maintenance outages (as described above). With no or lower interconnector exports, the GB's demand would reduce and, there would be a reduced supply deficit needing to be met by other supply sources including MH / LNG flows.

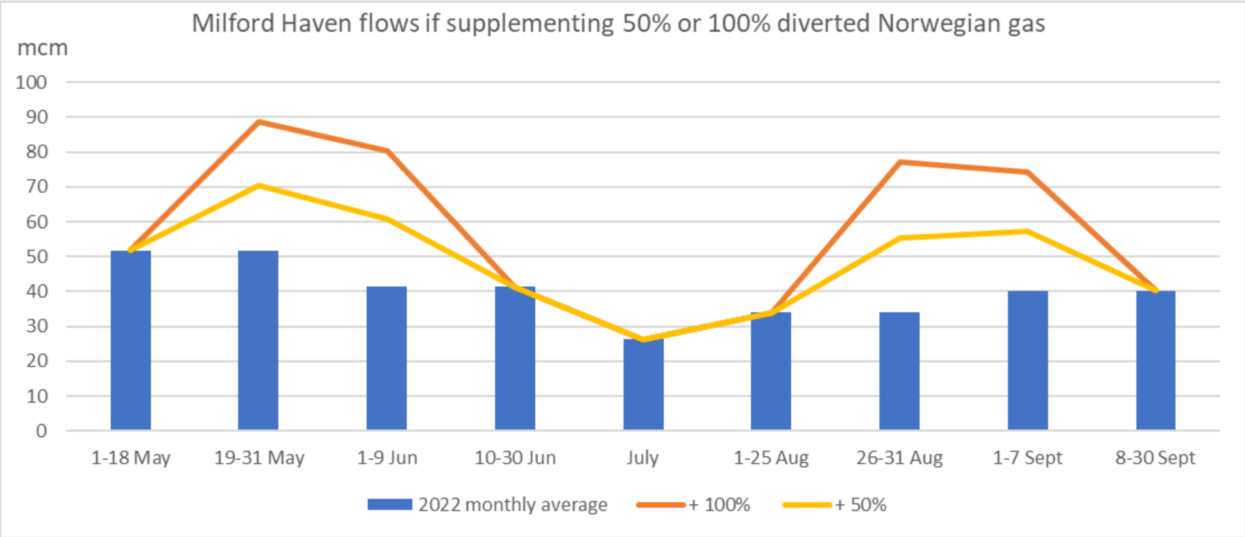


What the chart demonstrates is a clear demand for additional gas being delivered to GB in certain periods during the summer. The main periods impacted are May/Jun and Aug/Sep, but the supply/ demand position remains close in other months as well. It's worth noting that the graph above shows averages and not peaks.

Where the graph indicates that supply doesn't meet demand, this could be met by the market reacting by driving prices and as such potentially utilising gas out of storage, increased LNG deliveries, reduced interconnector flows or increased Norwegian flows (again will be price based driven by GB/EU price differentials).

As addressed in the consultation paper, we believe it is reasonable to anticipate that any reduction in Norwegian supply will mean an increased number of cargos being delivered to GB when the additional supply is needed. Recognising the importance of LNG deliveries from a security of supply perspective, we expressed a concern that the physical capability of the network will have an impact on increasing the constraint risk and therefore impact our customers and consumers costs via constraint actions being required.

We have considered the potential constraint risk if Milford Haven flows were to increase to supplement all or a proportion of Norwegian gas being diverted to Europe during the maintenance periods. To model this, we have used the average monthly flow from summer 2022 and added 50% and 100% of the forecast Norwegian supply deficit for the specific periods of maintenance. The potential flows that would materialise at Milford Haven in these scenarios are illustrated in the graph below.



Considering the average summer MH capability is 65mcm/d, it is clearly visible that should additional gas be supplied in response to the Norwegian deficit, the flows are likely to exceed the physical network capability.

Amended solution

The comparison of Norwegian loss of supply against flows in the last couple of years indicates that the loss of Langeled supply will have greater impact on GB. The loss in supply due to Vesterled outages will be less poignant and the potential increase in LNG flows should have lesser impact on the constraint risk.

4 respondents suggested more closely aligning the quantity of capacity made available with the timeframes of likely Gassco Langeled impacting outages and releasing more capacity in weekly auctions in periods when only Vesterled outages have an impact on GB supply. We have amended our proposal based on this suggestion and we will be submitting the following proposal to Ofgem for consideration:

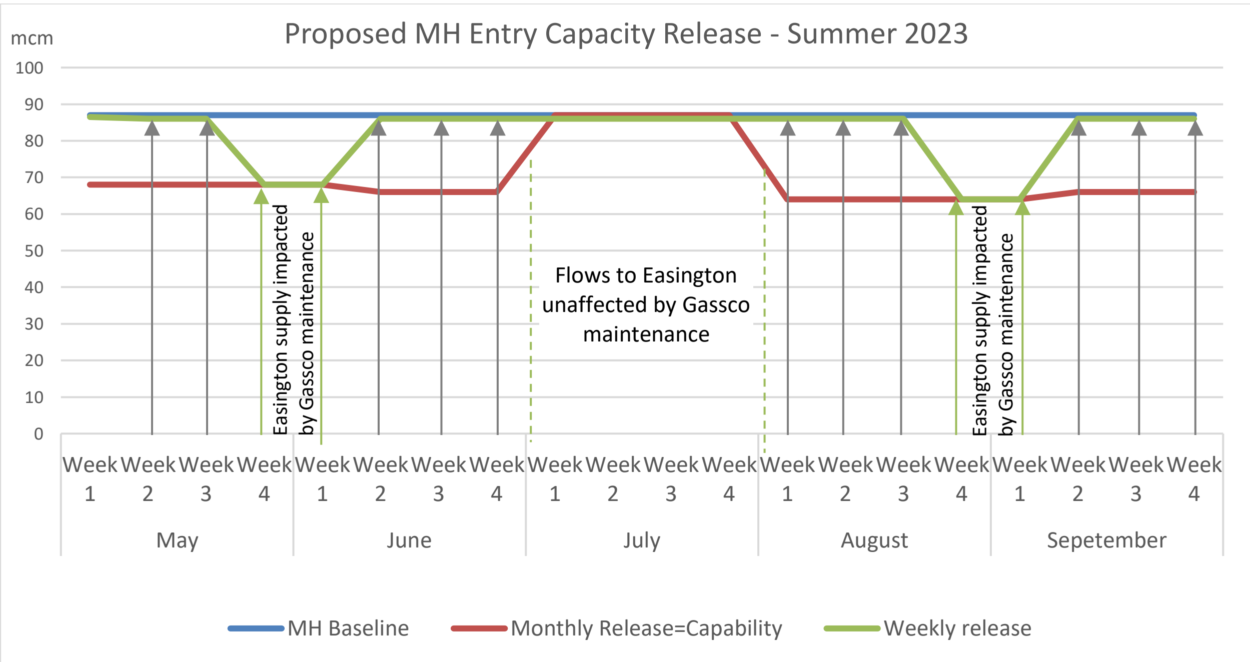
- **In annual monthly/monthly auctions**
  - Reduce MH entry capacity release to network capability level in annual monthly/monthly auctions affected by Gassco maintenance[6] (including where the maintenance is moved)
  - Should the Gassco maintenance be rescheduled or cancelled with sufficient notice prior to the relevant auction, and the change be applicable to the whole auction period, capacity will be released up to baseline (less any sold amounts) in the applicable month/s.

- **In weekly auctions:**
  - Release capacity up to baseline (less any sold amounts) for the weeks not affected by Gassco maintenance (including where the maintenance is moved)
  - Reduce capacity release to network capability (less any sold amounts) in weeks affected by Gassco maintenance (including where the maintenance is moved)
  - Should the Gassco maintenance be rescheduled or cancelled with sufficient notice prior to the relevant auction, and the change be applicable to the whole auction period, Capacity will be released up to baseline (less any sold amounts) in the applicable week/s

- **In daily auctions:**
  - The capacity will continue to be released up to baseline (less any sold amounts) for the days not affected by Gassco maintenance

- In instances when the weekly and day ahead capability assessment indicates a higher capability, then we will release capacity up to the higher capability level (less any sold NTS Entry Capacity), for days affected by Gassco maintenance.

Based on the current Gassco maintenance plan as at 26/01/2023, the following chart outlines details of the new proposal, with the red and green lines indicating the proposed level of capacity release in the annual monthly / monthly and weekly auctions respectively.



[6] For clarity, where referred to Gassco maintenance in the amended solution, this is Gassco maintenance with potential Easington impacts only i.e., where affected assets are Nyhamna and Kollsnes as per Gassco maintenance website

For clarity, the following table shows, based on the Gassco maintenance plan as at 26/01/2023, the entry capacity levels we would commit to release at MH. The Weekly auctions affected by Easington impacting Gassco outages have been highlighted. For a week spanning two months, the higher monthly capability number will be used to calculate the capacity offered in that weekly auction (to confirm, day ahead auctions will offer any capacity unsold in the weekly auctions, and within day auctions will then offer any capacity unsold at the day ahead stage.)

Proposed Milford Haven Capacity Release (Summer 2023)						
Annual Monthly (AMSEC) and Rolling Monthly (RMTnTSEC) Auctions effective	MH Capability mcm/d	Capacity offered mcm	Capacity offered kWh	Weekly Auction effective	Weekly capacity offered (mcm)*	Weekly capacity offered (kWh)*
1st May	68	68	748,000,000	1st May	87	957,000,000
				8th May	87	957,000,000
				15th May	**68**	**748,000,000**
				22nd May	**68**	**748,000,000**
1st Jun	66	66	726,000,000	**29th May**	**68**	**748,000,000**
				5th Jun	**66**	**726,000,000**
				12th Jun	87	957,000,000
				19th Jun	87	957,000,000
1st Jul	63	87	957,000,000	26th Jun	87	957,000,000
				3rd Jul	87	957,000,000
				10th Jul	87	957,000,000
				17th Jul	87	957,000,000
				24th Jul	87	957,000,000
1st Aug	64	64	704,000,000	31st Jul	87	957,000,000
				7th Aug	87	957,000,000
				14th Aug	87	957,000,000
				21st Aug	**64**	**704,000,000**
1st Sep	66	66	726,000,000	**28th Aug**	**66**	**726,000,000**
				4th Sep	**66**	**726,000,000**
				11th Sep	87	957,000,000
				18th Sep	87	957,000,000
				25th Sep	87	957,000,000

**Weekly capacity offered will be reduced by quantities sold in Monthly NTS auctions*

Should this proposal be implemented, paragraph 74 of the Entry Capacity Release Methodology Statement would be amended as follows:

74. Where, in respect of any given Gas Flow Day, circumstances arise in which National Grid foresees a capacity constraint occurring at an ASEP, National Grid may withhold capacity from sale for that ASEP in DSEC auction. Furthermore, National Grid may also withhold capacity from the AMSEC auction and some RMTNTSEC, WSEC and DSEC auctions in the period between 1st May to 30th September 2023 at the Milford Haven ASEP on the following basis[7]:

- In Annual Monthly System Entry Capacity (AMSEC) and Rolling Monthly Trade and Transfer System Entry Capacity (RMTnTSEC) auctions:

[7] In line with ECR amended proposal as published in the NGG's ECR Joint Response to ECR Consultation

- Firm NTS Entry Capacity release will be reduced to network capability levels[8] (less any sold Firm NTS Entry Capacity) in months affected by Gassco maintenance[9] (including where the maintenance is moved)
    - Should the Gassco maintenance be rescheduled or cancelled with sufficient notice prior to the relevant auction, and the change be applicable to the whole auction period, Firm NTS Entry Capacity will be released up to Licence Baseline Entry Capacity (less any sold Firm NTS Entry Capacity) in the applicable month/s.
- In Weekly System Entry Capacity (WSEC) auctions:
    - Firm NTS Entry Capacity will be released up to Licence Baseline Entry Capacity (less any sold Firm NTS Entry Capacity) for the weeks not affected by Gassco maintenance (including where the maintenance is moved)
    - Firm NTS Entry Capacity release will be reduced to network capability[10] (less any sold Firm NTS Entry Capacity) in weeks affected by Gassco maintenance (including where the maintenance is moved)
    - Should the Gassco maintenance be rescheduled or cancelled with sufficient notice prior to the relevant auction, and the change be applicable to the whole auction period, Firm NTS Entry Capacity will be released up to Licence Baseline Entry Capacity (less any sold Firm NTS Entry Capacity) in the applicable week/s.
- In Daily System Entry Capacity (DSEC) auctions:
    - Firm NTS Entry Capacity will be released up to Licence Baseline Entry Capacity (less any sold NTS Entry Capacity sold) for the days not affected by Gassco maintenance

- In instances when the weekly and day ahead capability assessment indicates a higher capability, then National Grid will release Firm NTS Entry Capacity up to the higher capability level (less any NTS Entry Capacity), for days affected by Gassco maintenance
- In all cases, any additional capacity released due to higher week ahead and/or day ahead assessments will be limited to a level which National Grid considers will not introduce any undue constraint risk or associated cost exposure for customers.

The average summer 2022 LNG flows circa doubled compared to the summer 2021 average flows, although for the most part flows did not exceed the capability of the network by some margin. We have no visibility of summer 2023 predicted MH flows, and no certainty of how impactful the Norwegian maintenance periods will be to either GB supplies or wider market dynamics. It is therefore very challenging to assess the likelihood of LNG flows exceeding network capability, and the level of associated constraint costs that may materialise. We do believe however, that the MH entry capacity reduction should be applicable during periods of Gassco maintenance (impacting Easington supplies), to effectively protect customers and end consumers from the risk of high constraint costs.

In their consultation response South Hook Gas stated that they *"…estimate the likely send out from the Dragon LNG terminal and seek to schedule our deliveries in a way that avoids NTS constraints."* We greatly appreciate both the openness of, and sincerity, behind this statement, and take assurance from this as desire to act as a prudent operator into summer 2023.

We recognise the criticality of our role in ensuring the GB and European gas industry functions in an efficient and effective manner whilst meeting customer requirements. We are working as a priority to ensure we can continue to maximise gas flows into and out of our network, to the extent that we are

[8] As published in the NGG's Joint Response to ECR Consultation
[9] For clarity, Gassco maintenance with potential Easington impacts only i.e., where affected assets are Nyhamna and Kollsnes as per Gassco maintenance website

able. In our view our amended proposal, if implemented, would successfully mitigate the risk of potential constraints at times where we see them most likely to occur, but at the same time, we think that by releasing full baseline capacity in majority of the summer, we would better allow LNG Shippers and Operators to maximise utilisation of existing capacity and capability of the NTS.

In this response we have tried to address the main issues raised by the industry. We would appreciate further engagement on the topic via the industry meetings and direct correspondence.

Please note that this response, as well as all non-confidential consultation responses, will be published on our website by Monday, 30th January 2023 under: https://www.nationalgrid.com/gas-transmission/capacity/capacity-methodology-statements.

Your sincerely

Chris Logue
Head of Markets

Appendix 1

Alternative solutions suggested via ECR Consultation responses

	Details
1.	Align volumes and timelines more closely with Gassco maintenance
2.	Release capacity at a value between that proposed and the baseline to provide headroom to support cargoes being contracted but which is unlikely to lead to a physical constraint
3.	Offer a weekly product with longer lead time (recognising releasing monthly capacity is untenable)
4.	Available LNG storage should influence appropriate locational trades and buyback prices.
5.	Locational sell trade could be executed at Pembroke Power Station if it was not already generating at maximum. Gas could be priced based on the level at which the generator could sell the power produced from it. This selling pressure would probably decrease power prices.
6.	Release the full baseline capacity for May. Should capacity end up being very tight, we envisage that deferrals might be made until June whilst June remains unsold, and will enable NGG to trial releasing full capacity levels.
7.	Offer alternative capacity to Users who execute locational trades or buybacks to give them confidence they will be able to reschedule gas injections that have been subject to those trades (reduce capacity procurement risk for them and hence might reduce the cost of locational trades).
8.	Capacity restrictions apply after a number of constraint days *(not in feedback, but considered by NGG in the past)*