Short Term Exit Capacity Consultation Response

Dear Emma,

Thank you for the opportunity to comment on the Utility Regulator's assessment and proposals for Short Term Exit Capacity products.

This response is on behalf of Mutual Energy, which owns three of the four licenced gas TSOs in Northern Ireland: Premier Transmission Ltd. (PTL), Belfast Gas Transmission Ltd. and West Transmission Ltd.

In this response, we have sought to provide information to specific questions raised. However, at various points we have suggested that further consideration or engagement may be necessary. Should you agree that further engagement is required, Mutual Energy would be happy to liaise further with the Utility Regulator (UR) on this issue, and likewise if you require clarification on any points raised in this response, we would be happy to discuss further with you.

Yours sincerely,

Rowan Tunnicliffe
Senior Commercial Analyst

1. Do Respondents consider that short term exit capacity products should be introduced? Please explain the reasons for your view and provide supporting evidence.

The question of whether short term products should be introduced is ultimately a policy matter for UR to decide. Historically, gas networks are paid for based on long term capacity requirements, rather than short term usage. This is to ensure that there is sufficient capacity available for all users of the network to use it when they want to.

Introducing short term exit products moves away from this approach. This will have fairly fundamental implications for the NI gas network and consumers and consideration should be given to how any additional capacity is to be brought on when required in the absence of the necessary long term signals.

The gas network is subject to security of supply standards as laid out in legislation, which you have referenced in the consultation document. This currently manifests itself via the 1-in-20 capacity booking requirement on Distribution Network Operators in terms of their exit capacity booking, laid out in their respective licences. This is a necessary, but not sufficient, action to meet the requirements laid out in the legislation. Further action is required to ensure compliance with that legislation, which is outside the scope of this consultation, but we refer to the actions required in response to question 5.

Power stations are not directly covered by the 1-in-20 requirement laid out in the legislation. However, the electricity sector does have its own security of supply standards[1]. Practically, the power sector in Northern Ireland is now almost fully reliant on the gas network to deliver security of supply. The inability of power stations to access sufficient gas via the NI network would mean that the 4.9 hours per year maximum Loss of Load Expectation laid out by the Department for the Economy would be undeliverable.

For the gas transmission network to meet the needs of Shippers going forward, it needs both (i) long term investment signals, and (ii) the ability to charge the users of the network for required network developments.

Annual products provide an imperfect solution to the first of these requirements, which would be enhanced by the proposals referenced in our response to question 5. Annual products also provide an established way of delivering the second requirement, ensuring that all users pay their fair share for the upkeep and development of the NI gas network.

Short term products do not deliver on either of these requirements. We understand that there might be wider policy benefits from delivering short term products which UR have identified. However, we have to be clear of the trade-offs involved in delivering on those other objectives using short term exit products in terms of the removal of investment signals in the NI gas network, increased costs on gas consumers and potential 'free-riding' on the NI gas network by power stations. Combined and without other mitigation, this means that either domestic and industrial gas consumers will likely cross-subsidise the power generators, or the security of supply for the electricity system will likely be put at risk by insufficient investment in the gas network.

2. We are interested in views on which exit capacity products should be available at exit. Do you agree that these options should mirror those currently available at transmission entry points with the exception of quarterly products? Please explain the reasons for your view.

If UR do decide to introduce short term products, then as a matter of equity between power station Shippers and gas consumers, there is a strong argument for the full suite of products being available to all Shippers, including quarterly products.

However, the impact of extending short term exit products to all Shippers would have fundamental implications for the cashflow of the gas TSOs, and it could put at risk Mutual Energy's ability to ensure sufficient incoming cashflow within a year to meet it's debt obligations. This is because annual products, billed monthly, guarantee regular payments to the TSO, which can then be used to pay bond payments in March and September each year. In contrast, with short term products, there is no such guarantee and the only guarantee of cashflow is at the end of year reconciliation, which itself has a cap mechanism further delaying cashflow.

There are conditions in the gas conveyance licences which place a duty on licenced entities not to discriminate between Shippers, for example Condition 2.11 of the PTL Licence places a duty on PTL not distort competition within the market. For this reason, if short term products are deemed to be appropriate for one Shipper, or one type of Shipper, then the Utility Regulator needs to be satisfied that

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/210963-EirGrid-Winter-Outlook-2022-2023.pdf

it is not discriminatory to make them unavailable for other types of Shipper, or that the discrimination is necessary to fulfil UR's wider policy objectives.

Despite this unfairness, if short term products are to be introduced, then in order to ensure that the network is maintained and consumers continue to receive the benefits of mutualisation, it may be proportionate to continue requiring distribution networks to maintain their 1-in-20 requirement via annual products. This would replicate our understanding of what happens in the Republic of Ireland, where technically Short Term Non-Daily Metered Exit Capacity is available, however in practice it is not used and Shippers serving domestic customers are required to hold sufficient capacity to meet their security of supply standard requirement.

Additionally, to reduce the inequality between power station Shippers and distribution customers, and given the increasing reliance of the electricity system on the gas network for security of supply, consideration should be given to applying a security of supply condition on power station Shippers also. For example, this might be requiring the Shipper to hold annual capacity equivalent to a power station's gas requirement for its minimum stable generation for a number of hours within a day (including start-up and shut-down requirements).

This would mitigate the potential issues in terms of ensuring sufficient monthly cashflow for TSO's as well as reduce inequities between the distribution and power station Shippers and partially resolve some of the 'free-riding'[2] problem in terms of network development and investment signals as outlined in question 4.

3. Are quarterly products required at the exit point? If so, why?

The nature of the gas demand profiles of gas distribution demand and gas fired power station demand means that it could be unfair on gas distribution customers if the choice given to distribution Shippers was between annual or much more expensive monthly/daily products. In actual fact the most cost effective option for gas distribution customers might be more 'seasonal' products, as this would ensure that their winter peak demand is met, but allow distribution Shippers to avoid over-procurement in summer, when demand is lower.

In contrast, power station gas demand might be much more 'peaky' throughout the year, which would mean that shorter duration products such as daily products provide a more cost-effective solution, even given their higher multiplier.

In this case, failing to offer quarterly products could mean that distribution Shippers are indirectly discriminated against and the market distorted, as cost saving opportunities would be extended to power station Shippers but not adequately extended to gas distribution Shippers.

Short term products might also be considered to treat different types of generators differently. For example, more efficient combined cycle generators (CCGTs) are less likely to benefit from daily products than less efficient open cycle generators (OCGTs). A CCGT's generation profile will be flatter over the year, making longer term products such as annual and quarterly with their lower product multiplier more appealing, whereas the monthly and daily products will be more beneficial to OCGTs.

[2] In this context, 'free-riding' refers to the idea that a party who uses network capacity infrequently, and who pays more proportionate to commodity use, contributes disproportionately less than the overall capacity costs, which do not vary with usage. For the avoidance of doubt, it does not mean that they pay nothing towards to network.

OCGTs could be considered to place more stress on the gas network given their comparatively poor efficiencies and likely use at peak demand times. As such, introducing short term products might allow less efficient generators to 'free ride' on the gas network to some degree, if the tariffs they pay are not sufficiently cost-reflective.

4. Are there any further risks or consequences that may arise as a result of introducing short term exit capacity products that we should consider? Please identify whether these consequences impact the gas or electricity market/consumers and provide supporting evidence.

Annual products can provide investment signals to gas TSOs, albeit imperfect ones. Removing the requirement to book annual products removes these long term investment signals.

For example, an annual auction currently might highlight a number of years out that there will be contractual congestion in a given Gas Year. In this case, the TSOs can assess the background to that congestion and consider what, if any, mitigating actions are required. The most cost effective solutions can then be developed.

In contrast, if short term products are used, then these 'advanced warnings' are unlikely to emerge, and congestion might appear with as short notice as a day.

In the case of contractual congestion, there may be commercial tools available to manage this, for example capacity buy-back measures where the TSO will pay a Shipper to reduce their capacity booking at certain times. However these types of congestion management products can come with ongoing charges, even if they are not used. Additionally, it might be the case that commercial mechanisms are either not economic, or simply not sufficient to resolve the problem when compared with physical development of the gas network.

Without the signals that the long term products send, the TSOs could end up over-procuring commercial congestion management tools, as the alternative in terms of physical congestion and potential lost load is even more costly. The costs of these tools are ultimately borne by all gas users, and so there will be 'hidden' costs from managing the network as a reasonable and prudent operator which will be created by introducing short term exit products.

Having no prior notice of forthcoming congestion will mean that TSO forecasts will be vital to ensuring sufficient procurement of commercial solutions for each forthcoming year. If TSO forecasts are inaccurate, then either there will be over-procurement of costly products, or indeed we might see physical congestion on the network and unserved demand

As an expansion to our answer to question 2, regardless of whether short term exit products are brought in for power stations, it will be important to maintain some sort of long term signalling for distribution networks as the risk of security of supply issues occurring in the distribution network poses a significant threat to safety on top of economic costs, therefore, the risk of unexpected congestion for distribution networks is unacceptable.

5. Are there any further mitigations which could be considered, including any that respondents may suggest from experience in GB and RoI? Please outline how these might be implemented.

A potential mitigation to the problem highlighted in our answer to question 4 could be provided by the introduction of a network development planning framework for the gas network. This approach would mirror similar approaches used in Great Britain and the Republic of Ireland. In GB, National Gas produce a ten-year network development statement[3] which covers anticipated need for network strengthening and different options available to do that. These options are then subject to cost-benefit analysis and those which represent a net positive to consumers are progressed. A similar approach is used in RoI where GNI produce a Network Development Plan[4] each year. These sorts of network development plans feed in to a pan-European network development plan developed by ENTSO-G.

Implementing this sort of framework to gas network development is a piece of work which needs to be progressed in Northern Ireland in any event, in order to tackle other challenges that gas TSOs are facing in terms being able to deliver new connections to market parties that are successful in the electricity capacity market, and challenges presented by the wider energy transition in terms of efficiently facilitating decarbonised gases, for example. However, in this context, it would represent a significant improvement on the longer term investment signals which are currently only provided in a limited way by annual products.

We are engaging and will continue to engage with UR and other stakeholders on this work.

6. We would welcome views on the assumptions underpinning the scenario analysis set out in chapter 3.

Assumption 3.2(i) is that in all scenarios, actual capacity bookings at entry are equal to forecast. This is a particularly strong assumption. There is no difference in incentives for Shippers to minimise the discrepancy between forecast and actual booked capacity at either entry or exit. As such, if forecasts are wrong at exit, then they are likely to be wrong at entry too. The magnitude of any under- or over-recovery is likely to be more than is laid out in the analysis. As such, the magnitude of reconciliations with short term exit products is likely to be far greater than the values laid out in this modelling.

7. Do respondents consider there are other scenarios which should usefully be modelled at this time?

We believe that modelling also needs to be undertaken to assess the longer term impact of these proposed changes, beyond just the forthcoming gas years. With increasing renewable energy penetration on the all-island network, and challenging targets for decarbonisation of the power sector, we will inevitably see gas generation increasingly moving from providing baseload generation to peaking generation.

[3] https://www.nationalgas.com/insight-and-innovation/gas-ten-year-statement-gtys

[4] https://www.gasnetworks.ie/corporate/company/our-network/network-development-plan/

In this instance, gas demand will become more unpredictable as it will be driven by the level of available wind generation. Load factors of gas units will also decrease dramatically, meaning that costs will need to be recovered over a much smaller number of periods. This might create undesirable impacts for both gas and electricity consumers (see answer to question 9).

While load factors might decrease, peak gas demand from power stations is likely to increase with more electrification, as more back-up generation will be required for when the wind does not blow. In this scenario, not only will electricity prices become more volatile, but also the gas network will likely need investment to facilitate this additional generation especially if inefficient gas generators are built which in effect almost doubles the amount of gas needed for the same amount of electrical output. It is not equitable to expect domestic gas consumers to pay for that and allow generators to reduce their contribution through accessing short term products.

Rather than just seeking to assess the impacts over the coming few gas years, longer term, strategic thinking is required to assess the interactions between the gas market and the decarbonisation of the power sector, to ensure that costs are predictable and fairly distributed.

8. In chapter 3 we have attempted to model the future use of gas capacity by the power sector and the impact this could have on cost allocation between the power and distribution sectors and on the reconciliation. We would welcome:

8.1. Commentary from respondents in the power sector on whether our assumptions on future use of gas capacity by the power sector are robust;

Please see answer to question 7.

8.2. Further information from respondents in the power sector which would assist us to refine these scenarios in chapter 3 for the 24/25 gas year

Please see answer to question 7.

8.3. information from respondents in the power sector which would assist us to model a scenario for the 26/27 gas year.

Please see answer to question 7.

9. Do respondents have any views on the impact that short term exit capacity products would have on prices in the SEM?

As more renewable energy comes onto the electricity system, short term exit capacity products could increase electricity price volatility substantially.

Northern Ireland has a target of 80% wind generation by 2030. SONI will be operating the all-island electricity system at up to 95% wind generation at any given time. This means that the future role for gas generation will become more flexibility provision and peaking generation than baseload generation, as it currently is.

The implication of this is that individual generators might prefer short term exit products as it allows them to book gas capacity on a more granular level and avoid paying for capacity when they are not using it.

However, at an overall level, the total cost of the gas network is not decreasing in line with the reduction in generator demand. That means that TSOs will still need to recover the costs accordingly. The same level of costs will need to be recovered over a smaller number of periods from the power sector, meaning that the gas transportation costs for a given MW of generation will increase.

This effect would be compounded in the long run, should the introduction of short term products push a larger proportion of the gas transmission network costs onto distribution users. This would have a direct and unfair negative impact on end consumers, who would be paying increased costs in relation to gas capacity that has been developed to meet the needs of the power generation sector.

In addition, if gas transmission network costs end up being recovered from the power sector in an increasingly small number of periods, this will make the per unit cost of electricity in those periods extremely high. Over the longer term, some form of fixed charge for power generation access to the gas transmission network (irrespective of capacity booking or usage), might be preferable, reflecting that holders of electricity capacity market contracts rely on the gas network to deliver their obligations.

10. Irrespective of whether short term exit capacity products are introduced do you consider that the ratchet mechanism needs to be reviewed? If so why?

The ratchet mechanism allow Shippers to purchase gas efficiently, ensuring that they pay their fair share of the network costs, without risking over-procurement and capacity hoarding – for this reason we believe that it should be maintained. In the case that either a power station or distribution network Shipper does not book sufficient capacity on a day, then they should be subject to a ratchet on annual capacity for the relevant amount. This would mean that there is less likelihood of having capacity shortfalls on a day, or at least providing some warning of future congestion. This would be preferable to overrun charges unless these are set at the price of annual capacity.

We are aware that some power station Shippers have concerns about the impact of the ratchet creating distortions in bidding behaviour in the SEM. Whilst understanding these concerns, we think that there may be undue focus placed on what is essentially an edge case. The potential implications of introducing short term products seem disproportionate to the problem aiming to be solved.

While the SEM Balancing Market Principles Code of Practice (BMPCP)[5] does say:

"The incremental exit gas transportation costs, at the point of consumption, that is required for the generation of an additional unit of output, may also be included [in bids]."

The important word here is "may", there is no obligation on power stations to include ratchet costs in their bids, and they could seek to recover the costs elsewhere, or spread over a longer period of time, rather than attempting to recuperate the ratchet cost solely in the marginal MW. We note that parties impacted by ratchet costs are likely to hold electricity capacity market agreements and will be obliged to

[5]https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-049%20Balancing%20Market%20Principles%20Code%20of%20Practice.PDF

deliver their obligations to avoid exposure to non-performance difference charges. We also note that the operation of the strike price in the SEM should cushion consumers from any impact of high electricity prices arising as a result of ratchet costs being included in electricity prices.

The BMPCP also only applies to the SEM balancing market, which is primarily used by SONI to manage the electricity system, not trade energy. While competitive pressures will impact bidding behaviour in the ex ante markets, there is much more flexibility on bidding strategies from a regulatory compliance perspective.

We also have observed historically power stations using the ratchet within year to refine their capacity position, as such it cannot be prohibitive in terms of bids into the SEM.

We also note that power station Shippers are currently subject to the annual reconciliation process, which can result in significant charges which they then seek to recover via their participation in the electricity market. This suggests that there is clearly a mechanism by which they can recover costs outside of their bidding strategy on the marginal MW.

11. Do you agree with our proposal to replace the ratchet mechanism with a capacity overrun mechanism? If not are there any other alternatives to capacity overrun mechanism you can suggest?

Capacity overrun mechanisms typically put punitive costs on Shippers for exceeding their booked capacity. As such, in the absence of a ratchet mechanism, they may incentivise Shippers to over-book capacity, and create artificial contractual congestion, requiring costly capacity management tools.

However, in the case where short term exit products are introduced, this is a risk that is worth taking as there needs to be an incentive for Shippers to actually book sufficient capacity. Failure to book sufficient capacity could lead to significant issues managing the system. Simply applying a ratchet on a daily product, for example, in this case would not provide sufficient incentive to adequately book capacity.

12. Are there any circumstances which would warrant the retention of the ratchet mechanism?

Should short term exit products not be introduced, the ratchet mechanism allows Shippers to book capacity efficiently and optimally, and does not incentivise overbooking or capacity hoarding.

13. Do Respondents have any views on our assessment of the impact that the introduction of short term exit capacity products may have on how gas transmission required revenues are allocated between the power and distribution sectors?

The introduction of short term exit products will disproportionately benefit the least efficient generator units who have the lowest load factors and least predictable generation profiles. More efficient plant which operates on a ‘baseload’ basis will have less need for short term products.

Gas transportation costs will have a proportionately smaller impact on the overall cost base of these inefficient units, where changes in the fuel price will be more dominant determinants of their overall costs.

Additionally, these less efficient plants will set the marginal price of electricity only a fraction of the time. As such, it is unclear how much overall impact reducing gas transportation costs for these types of generator unit will actually have on electricity prices. As the introduction of short term exit products will inevitably shift costs from power station Shippers to gas distribution customers, it is not clear that this will necessarily represent a direct shift in benefits from end gas consumers to end electricity consumers. Rather there is likely to be significant economic capture by the least efficient generator units.

We have outlined concerns about how required revenues are split between the power and distribution sectors in the longer term more fully in our responses to question 7 and question 9. However, in summary, we see potential need for network development to meet the increasing gas requirements of the power generation sector going forward as the energy transition picks up pace and more electrification is undertaken. This may require additional spending on the network, and it is not equitable or indeed sustainable to expect the gas distribution sector to bear an unrepresentative share of the costs of network development which is primarily for the benefit of power stations.

14. Do Respondents have any views on whether the introduction of short term exit capacity products will increase the risk of delayed payments to TSOs and what issues the TSOs may face as a result?

Currently, requiring the booking of annual products provides a guaranteed level of cashflow to TSOs across each month of the year. This ensures that the TSOs have sufficient incoming cash to meet their outgoings. In the case of the mutualised companies, a key outgoing is the bond payments on the financing for the assets. Minimising the risk of non-payment for these bond payments allows Mutual Energy to access the cheapest possible lending for the benefit of NI consumers.

Introducing short term exit products could increase the risk of cashflow issues as it reduces the guarantee of having a monthly income stream from the annual products. While the reconciliation ensures that all money will eventually be recovered, the annual products provide certainty for TSOs of income coming in throughout the year.

In the final design of any short term exit products, it will be of the utmost importance that potential liquidity issues for TSOs are addressed. Significantly changing the risk profile that TSOs, and their lenders, face without putting in place mitigating measures would not be acceptable.

Additionally, as evidenced by the analysis that is presented in the consultation paper, the introduction of short term exit products will likely increase the value of the annual reconciliation at the end of each gas year. These can be either positive or negative, depending on whether the TSOs have over- or under-recovered during the year.

In the case where the TSOs have under-recovered and a payment from Shippers is required, increasing the size of the reconciliation will inherently mean that there is an increased risk of non-payment as Shippers need to have the liquidity to make the payment. This leads to considering the possibility that collateral requirements for Shippers might need to be increased.

Additionally, as outlined in our answer to question 4, overall costs might increase with the introduction of short term exit products as TSOs may need to procure additional congestion management tools to ensure that they can manage the system under an increased number of uncertain scenarios. This will further increase overall costs which will be passed on to Shippers.

15. If so, how should any increased risk of volatility in required shipper payments be managed following the introduction of short term exit capacity products?

Please see answer to question 18.

16. Do Respondents have any views on whether the introduction of short term exit capacity products will increase the risk of volatility in the reconciliation payment?

Yes, the analysis presented clearly shows this. Additionally, one of the key drivers of volatility in the reconciliation payment currently is the difference between forecast and actual bookings for different entry products, so it is intuitive that this impact will be replicated at exit should short term products be introduced.

17. Does the current level, or potential future level, of volatility in the end of year reconciliation pose issues for gas suppliers? If so, in what way?

No answer.

18. We would welcome views on the potential mechanisms to mitigate this risk of volatility set out in paragraph 5.40.

18.1. Seasonal multipliers

We note that the Utility Regulator has issued a concurrent consultation specifically on seasonal multipliers, which we will respond to separately.

We understand the appeal of removing seasonal factors as power station gas demand is generally dictated by wind, rather than seasonal multipliers.

However, we understand that the idea of introducing short term products is to align more with the Republic of Ireland in terms of costs facing NI power stations. We therefore query whether changing the seasonal multipliers and diverging from those used in RoI is a consistent approach.

Additionally, seasonal multipliers also provide additional security for the liquidity of the gas transmission owners. This is because having a higher factor in winter means that revenue recovery is ‘front-loaded’ within the gas year, increasing the probability that the TSO has sufficient cash to meet its payment obligations throughout the gas year.

As such, removing seasonal factors could exacerbate the liquidity issues that we have identified within this consultation response.

18.2. Providing forecast reconciliation numbers throughout year

While this will give Shippers the information that a large reconciliation may be coming, a warning can only ever be partially helpful as Shippers then need to go and actually gather the cash reserves to pay any reconciliation. While a helpful measure, other solutions which seek to minimise the size of reconciliations may bring more benefit to Shippers. It is also important to note that forecasts will have limited impact in terms of resolving potential cashflow issues for TSOs as a result of short term products.

18.3. Buffer account

We discuss this in more detail in question 19.

18.4. Incentivise accurate forecasts

We would be supportive of this, however we appreciate that it might be difficult to achieve in practice as power station Shippers will have increasingly unpredictable gas demand, largely based on wind availability.

18.5. Mid-year tariff review

We would need to understand how this would work in practice; would the updated tariffs seek to recover any under-recovered costs from the earlier part of the year in order to minimise the reconciliation, or would it simply look to ensure that there is no further under-recovery going forward and use the reconciliation to recover the initial under-recovery?

While in principle this approach might have merit, there is a risk that it becomes administratively burdensome.

19. Do you consider that the concept of a 'buffer account' should be explored further and do you have any additional thoughts on how this should operate?

A buffer account could be introduced to solve two distinct issues: (i) the potential liquidity issues facing TSOs as a result of short term products, (ii) to smooth end of year reconciliation amounts for Shippers.

In terms of the first use case of reducing the likelihood of liquidity issues for TSOs, our view on how this should operate at a high level is that this buffer should be available for significant negative discrepancies between forecast and actual revenue within a gas year which pose cash flow issues for the TSOs. For example, where tariffs have been set by high Shipper forecasts for capacity bookings which do not materialise within the year, this could create a 'missing money' problem within year for the TSOs who would have anticipated larger monthly payments. While this will be resolved by the reconciliation process at the end of the year, it might pose cashflow issues before that. The buffer account is anticipated to allow TSOs to access cash to maintain their required payments such as scheduled debt repayments for bond financing.

Practically, we would expect that this pot should only be accessed where actual revenue falls below a certain proportion of forecast revenue within the year. Whatever money has been withdrawn from the pot at the end of the gas year would then be recovered as part of the reconciliation payments made by Shippers.

We appreciate that this might create the requirement for large, one-off payments from Shippers as part of the reconciliation. However, this simply represents a change in the timing and sharing of the annual costs of the gas transmission network. Certainty of both liquidity and cost recovery are key elements required to maintain Mutual Energy's ability to access lower cost debt financing for investment in the gas network, reducing costs for consumers. As such, in the final design of any short term product regime, liquidity issues must be addressed.

The second use case for a buffer account might be to smooth reconciliation payments for Shippers. This would mean using the buffer account to reduce high reconciliation payments from Shippers in one year, allowing them to be factored into tariffs in future years. It is not clear that this would be the most efficient approach to minimising the impact of reconciliations on Shippers, and there is a risk that it compounds the monetary size of future reconciliations.

The considerations outlined in paragraph 5.40(c) of the consultation document are all valid considerations and specific focus will be required on resolving the policy and practical issues ahead of implementation. We would welcome further engagement with UR on this.

Additionally, there may be additional considerations based on how exactly the buffer account is implemented. For example, it might be appealing to refill the buffer account via the tariff mechanism in the subsequent gas year, spreading the cost for Shippers rather than exacerbating an already large reconciliation payment at the end of the gas year. However, in this case we have identified an additional consideration regarding the timings of the tariff setting and reconciliation process which may necessitate a higher buffer being held in relation to more than a single gas year.

Essentially, if the buffer is to be refilled using tariffs in the following gas year, then the information regarding how much is required from the tariffs will not be available when the tariff for GY+1 is set. The final amount to be recovered will only be known after the end of the initial Gas Year. This means that the buffer could be depleted after the end of GY, and should the buffer be required in GY+1, the money would not be available. As such, the buffer will need to be of a sufficient size to cover potential shortfalls in two consecutive gas years.

We feel that the specific design of the buffer account will need further consideration between the Utility Regulator and the TSOs, and given the potential impact on Shippers, may necessitate a separate, dedicated consultation.

20. We would welcome a view from MEL as to whether there are monies currently held for the benefit of NI gas consumers which could be used as the initial deposit for the buffer.

We understand from engaging with the Utility Regulator that this question refers to funds held by PTL in its "social enhancement account" which was established in 2004 upon the mutualisation of PTL (achieved via its acquisition by Northern Ireland Energy Holdings Ltd.) through a decision by the Northern Ireland Authority for Energy Regulation which stated that the fund should be aimed at supporting measures which reduce overall costs to gas consumers. The proposed buffer account would either merely maintain a liquidity facility or move the timing of reconciliation payments, and does not materially reduce overall costs to consumers.

Importantly, short term exit products as a concept will not reduce overall costs to gas consumers, they will likely just shift costs from power stations to distribution users. As our answer to question 4 highlights, there is also a risk that removing the investment signals that annual products bring might also increase the overall costs of managing the network, thereby increasing overall costs to consumers. This would be in direct contradiction to the stated aims of the social enhancement fund and therefore we feel that it would be inappropriate to use these funds for this purpose.

Given short term exit products are simply a redistribution of costs, our view is that should UR decide to progress with the implementation of these products, then as a principle the Shippers who benefit from these products should contribute to the buffer account.

21. If short term exit products capacity were introduced, would DNOs avail of these products in order to meet the 1 in 20 obligation? Please provide reasoning for your view.

While we cannot answer on behalf of DNOs, we note that their current 1-in-20 licence obligation is a necessary but not sufficient condition to ensuring security of supply. Legally, the obligation to maintain security of supply in accordance with the Gas (Security of Supply and Network Codes) (Amendment) (EU Exit) Regulations 2019) applies to all gas undertakings, not just DNOs.

This means that the NI transmission network needs to be designed in such a way that security of supply standards can be maintained, and the Utility Regulator should facilitate a sufficient framework to allow all gas undertakings to maintain security of supply. The workstream outlined in our response to question 5 aims to ensure the NI transmission network can comply with this. In the interim, the investment signals provided by annual capacity bookings are the best available approach that TSOs have to ensuring system adequacy but, as previously explained, this is an imperfect approach.

22. If short term exit capacity products were available who should have responsibility for booking these - the DNOs or gas suppliers? Please explain the reasons for your view.

No answer.

23. What would be the implications of changing the booking responsibility?

No answer.

24. The NI Network Gas Transmission Code includes arrangement for secondary transfer of exit capacity. Do Respondents consider that these arrangements would need to be reviewed if short term exit capacity products were available? If so, in what way?

No answer.

25. We note that a potential introduction of an ex-ante entry:exit split, which would recover a higher proportion of cost from entry capacity, could reduce the impact of the 1 in 20 obligation. Do Respondents have any views on this?

No answer.

26. We are interested in views on how forecasting of gas capacity bookings could be improved at entry and exit points.

Having individual generators forecast their own dispatch might not be the best approach given that the SEM is a central dispatch market. Rather, SONI should engage and provide forecasts for dispatch to allow gas TSOs to better assess the likely demand for gas capacity at various points in the year.

27. Are there any further matters that should be considered?

No answer.