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Dear Paul,

Thank you for the opportunity to respond to the "RIIO-T1: Consultation on draft decision on National Grid Gas Transmission's application under the RIIO-T1 Compressor Emissions uncertainty mechanism". Our interpretation of Ofgem's minded to position is in essence to delay making a decision until the 2018 reopener window. In this response by National Grid Gas Transmission (NGGT) we raise our concerns about this approach and provide further evidence to respond to the key points raised by the consultants.

Delaying a decision on the IED proposals to 2018 will create significant regulatory uncertainty, which is not in the interest of consumers or users of the gas transmission network. It is imperative that there is a clear approved plan of work to ensure compliance with the IED requirements by 2023. Compressor replacements typically take between 5 -7 years to complete and the respective outages need to be sequenced. According to our current plans, all key decisions would need to have been taken before 2018 and the majority of projects would be in-flight. However, the regulatory uncertainty created by what would then effectively be ex-post regulation in 2018 will lead to investment decision delays with more works being scheduled for later in the programme wherever this is possible. This approach is therefore likely to reduce bundling opportunities, for example at Peterborough and Huntingdon, and lead to less efficient delivery, which will ultimately increase costs to consumers.

We believe the combination of our original submission and this response provides the information to enable an appropriate decision to be taken. This would also endorse the RIIO-T1 principles of the importance of stakeholder engagement. Stakeholders have actively engaged in the development of the IED Submission and are supportive of the plans, which will deliver the network that our customers require. The process followed in reaching Ofgem's minded to position has, in our view created a risk that stakeholders will see little merit in in contributing to future RIIO debates.

In addition to providing further information in respect of the four main areas of concern raised by Ofgem, this response also addresses a number of what we believe are factual errors in the consultant's report and revisits our thinking in respect of units classed as Medium Combustion plant. Our comments in all of these areas are set out below.

Cost / Benefit Analysis (CBA)

The majority of the Poyry report focuses on their view that there is a lack of evidence to support the proposed decisions. However, in discussions with Poyry they have clarified that this is not to say that they think any of the proposed decisions are the wrong economic choices, more a case of the supporting evidence being insufficient.

Our approach to cost benefit analysis was developed with our stakeholders and through it we jointly evaluated the range of viable options for the affected compressor units, with a detailed costing produced for the recommended option. Stakeholders have been fully supportive of the process and have been satisfied with the level of information provided to make an informed decision on the appropriate solution at each site. Through the process we have always provided more information to stakeholders where this has been requested.

In light of the response from Ofgem and their consultants we have further explored whether there is additional evidence we can provide to support our recommendations. Below we provide clarification of the analysis undertaken and put this in the context of the wider capacity regime. It is worth noting that none of the fundamental drivers for the recommended options is system flexibility, which Poyry discuss at length, with the lack of quantification of system flexibility issues being one of their principal concerns. System flexibility is a key concern of stakeholders and we are currently working with stakeholders to understand their requirements and the associated costs. For the IED assessment we agreed with stakeholders to qualitatively assess system flexibility to ensure the impact of our options was understood, however as stated this did not drive the fundamental decision at any of the sites.

NGGT has obligations to make capacity available at entry and exit points every day of the year, independent of actual or forecast supply and demand. The obligations are specified in the Gas Transmission Licence and they provide certainty to the market of the capacity that NGGT will sell. However, NGGT can choose how to manage its capacity obligations, for example through physical capability or constraint management actions. Physical capability can be provided in a number of forms, for example new pipes and compressors. Similarly constraint management actions can be undertaken through different methods, for example forward contracting or buying back capacity on the day. The cost of undertaking constraint management actions is highly dependent on the particular situation, for example the number of available players at the entry or exit point, the duration of any action and the volume required. In addition to the specific costs of the constraint management action, constraints at entry points also restrict gas supplies, which is likely to have an impact on wholesale gas prices.

To incentivise NGGT to strike the right balance between physical build and constraint management actions, a constraint incentive scheme was developed as part of the RIIO-T1 price control. Based on the strength of the incentive scheme and cost of buy back actions, it is uneconomic for NGGT to develop a network with long term constraints (See Appendix 1). However, the mechanism provides appropriate incentives to balance short term constraints, for example due to investment or operational outages. For the development of the RIIO-T1 constraint scheme a constraint value of 0.6 p/kWh was used, this was based on a mix of buy back and location buy /sell actions.

When we consider the benefit that a compressor provides to the network, at the highest level we define this as a network capability value. The network capability value varies depending on many factors, for example supply and demand patterns and network configuration. Typically a compressor will provide between 5-20 mcm/d (55-220 GWh/d) of capability. If this capability was not available, depending on the conditions we may need to buy the associated capacity rights back from the market. Based on a constraint value of 0.6 p/kWh, the benefit associated with a compressor could be considered to be between £0.35-1.4m per day, combined with any impact on the wholesale gas price. Therefore if we decommission a compressor unit and reduce our capability below our obligations this is the potential cost if users then decide to flow at the obligated level. It can be seen from this that constraint costs could be very material and the majority of this cost, and any impact on the wholesale gas price, would be borne by consumers.

There has been no reduction in our baseline obligations through this process and so in developing our proposals we have worked with stakeholders to minimise the costs of complying with IED, whilst ensuring that we retain sufficient capability to deliver the capacity obligations where there is the potential to flow gas against them. In Appendix 1 we go through the Hatton need case and demonstrate that the associated constraint costs, not taking into account the impact on wholesale gas prices, outweigh the cost of the investment. Similar analysis has been performed on all other affected LCP compressor sites and we concluded that the cost of replacement outweighed the potential cost of constraints. This CBA approach enabled us and stakeholders to differentiate between those sites where investment is the optimum option and those for which derogations and/or commercial options are viable. Based on this, we have then been able to explore more detailed solutions.

Retrofit Option

A key part of the Penspen consultant report is the applicability of retrofit technology, they state:

> *4.1.3 Retrofit*
> *The option to retrofit is briefly discussed in the NGGT submission. NGGT refer to detailed studies which they made of compressor retrofit options, however these are not currently available for review. The BREF document [4] gives a number of retrofitting options which are considered BAT for reducing NOx emissions, but these are not mentioned here. These rely on reducing the overall combustion temperature inside the turbine. Broadly they can be categorised based on whether they are dry or wet.*
>
> *Dry methods include DLE and DLN. DLE technology has been used to upgrade the existing engines at Aylesbury and so it is not clear why this is not considered elsewhere.*
> *Wet methods include steam or water injection, which may be preheated with the turbine exhaust gases (e.g. Cheng cycle). The wet systems have the disadvantage of reducing the life of the turbine, but can be effective in reducing NOx.*
>
> *NGGT reject this option based on their stated findings that retrofit is only minimally less expensive than replacement. In fact retrofitting costs for DLN vary considerably between manufacturer and model, [4]. Therefore NGGT should have obtained retrofit quotes for the specific turbine makes and models involved in order to justify their conclusions. However, there is no mention of any such quotes obtained.*

We accept that a retrofit option could represent a viable option on relatively new plant, where there is sufficient space, the condition of the remaining plant is good and the operating envelope requirements are largely unchanged from the existing unit. Hence NGGT undertook a number of activities to investigate the technology, as described below.

NGGT requested companies to tender to be part of a compressor Original Equipment Manufacturer (OEM) framework in 2012 for the IED programme of works and part of this tender included a retrofit category. Only one OEM tendered for this category and although two retrofit options were offered, one for the RB211 and one for the Avon engine, only the RB211 DLE retrofit had the potential to achieve the required emission levels. NGGT evaluated the RB211 DLE retrofit during 2012, with sample studies conducted at Hatton and St Fergus. Based on the outcome of these studies, the retrofit option was discounted for the compressors affected by the LCP element of IED. The reasons for this are summarised below.

The retrofit RB211 DLE machine is significantly different in many aspects to the existing RB211 installed and would necessitate major modifications and replacement of existing equipment. For example at Hatton the following assessment was made:

- A new hydraulic starter would be required and need to be located outside of the engine enclosure. The unit exceeds 85 dBA, requiring noise assessment and potential attenuation measures.
- A new fuel module would be required.
- A new lube oil system, with additional cooling would be required.
- An upgrade to the control system would be required.
- Due to age and/or condition, it would be recommended to overhaul the ventilation system, combustion system, power turbine and compressor.
- A number of interfaces from the new gas turbine to the package would need to be amended, including air supply.

In addition the new engine is larger and 1565 kgs heavier than the existing unit, which would require modifications to the enclosure, machinery door, deck plate walking surfaces and engine removal crane. The enclosure roof would need to be modified to raise the roof height to allow the crane to lift the engine to the appropriate height for engine removal.

The units at Hatton were installed between 1989 and 1991, therefore the majority of the equipment will be over 30 years old by 2023, with a nominal design life of 40 years. Undertaking the extensive engineering works described above would trigger a review and potential upgrade of all other ancillary and support systems, for example fire and gas systems.

At Hatton, the existing units are located too close together and too close to the control building than would be allowed under current HSE guidelines. The existing units operate under “grandfather” rights, but any significant re-engineering, such as described above, would trigger a requirement to address these issues. This would therefore result in a major redesign of the site.

In terms of performance, the new retrofit RB211 DLE would need to operate in conjunction with Unit D, which is a 35 MW electric driven compressor. In Appendix 2, we show the typical duty points at Hatton and the points that would need to be covered by the RB211 DLE retrofit in either single or parallel operation with the larger unit D. The vast majority of the data points are below 70% load.

Below 70% the RB211 DLE retrofit is not able to meet the CO emission levels as specified in the IED. It would therefore not represent a BAT solution.

To have fully costed the retrofit option would have required spending significant sums on a Front End Engineering Design (FEED) study. Based on the fact that the solution did not represent BAT and the initial study indicated a requirement for extensive engineering changes we discounted the retrofit option for Hatton.

For clarity in the case of Aylesbury the units originally purchased were prototype DLE machines, these were not retrofits performed on existing assets.

Selective Catalytic Reduction (SCR) Option

A further key part of the Penspen consultant report is the applicability of SCR technology, they state:

> *4.14*
> *Reduction of NOx*
> *In their analysis NGGT rightly mention the hazardous nature of the reducing agents. Ammonia can be stored and used as a dilute solution in water which makes it less hazardous. The actual storage volumes needed vary depending on the size of the plant and running hours. However, general space constraints are important in determining if SCR can be implemented.*
>
> *NGGT assert that this technology is more suitable for units with low running hours. This would have to assume that the supply and storage of the reducing agent is significantly more costly than fitting a catalyst bed into the exhaust stack. This is possible, but sounds unlikely. In fact BREF (p773) [4] describes the technique as not being applicable to emergency plants due to their intermittent operation. This may include many of the smaller MCP units.*
>
> *NGGT describe how the technology is not yet proven or demonstrated for this application. In fact the BREF document [4] refers to a number of countries which are using them:*
>
> *"Many gas turbines currently only use primary measures to reduce NOX emissions, but secondary systems, such as SCR systems have been installed at some gas turbines in Austria, Japan, Italy, the Netherlands, and in the US (especially in California). It is estimated that approximately 300 gas turbines worldwide are equipped with SCR systems." [4]*
>
> *The SCR BAT [7] which was produced for NGGT is a very general document. It doesn't provide an individual BAT assessment for each site.*

We undertook a BAT assessment, which was a comprehensive review of the technology, but we accept it was not done on a site by site basis. However, the BAT assessment concluded that the technology is not yet proven for gas transmission applications. Based on the information available there are no operational examples of SCR fitted to gas turbines operating within the gas transmission sector, although we are aware of some projects being developed in this area. Additionally, as referenced by Penspen, the BREF does not consider the technique applicable to emergency plant due to their intermittent operation and we use our compressors in an intermittent manner. As the works on our compressors affected by the LCP element of IED need to be completed by 2023 and typically take 5-7 years to complete, we are not able to wait for proof of the viability of SCR. Based on these points, we therefore stand by our assessment that at this point in time we could not recommend SCR as a viable solution. However, it is appropriate to undertake an innovation project to assess this promising and emerging technology for gas transmission application, which we would hope to become a technical option for our units that will be impacted by the Medium Combustion Plant (MCP) legislation.

IPPC

Penspen undertook a brief review of the IPPC4 plans and concluded

> *In terms of IPPC Phase 4 proposal there is not enough evidence to support the choice of stations to upgrade, and no analysis is provided to support the decision to replace the units.*

As part of the IED legislation, flowing from the previous IPPC requirements, all relevant installations need to have a permit and the permit conditions should be based on BAT. It is recognised and understood that it is neither possible nor economic to comply with the BAT requirement across our whole fleet immediately. Therefore we have agreed with the environmental agencies to develop an environmental investment plan through an annual Network Review, which is embedded within the permit conditions. The Network Review document seeks to achieve the following:

- To identify the key environmental priorities with regard to ongoing operation of the compressor fleet.
- To identify suitable key technologies, which are commercially available, to drive natural gas compressors
- To identify a process by which Best Available Techniques are identified and delivered for all future compressor projects.
- To set out the challenges and factors affecting compressor utilisation into the future.
- To identify the most appropriate Network Environmental Investment and Regulatory Strategy for NGGT, to ensure maximum environmental returns, and ensure ongoing regulatory compliance and consistency.
- To agree NGGT's Network Environmental Investment and Regulatory Strategy with the EA, SEPA and NRW.

Based on predicted running hours and emissions, taking into full account the planned works at Peterborough and Huntingdon, we have agreed through the Network Review process that the three next most polluting sites are St Fergus, Peterborough and Huntingdon. This running hour information is reproduced in our Submission, and in Appendix 3 of this response we have included the emissions data that supports the choice of sites.

In terms of solutions, there is not a suitable retrofit solution for the Avon engine (as it does not sufficiently reduce emissions) and similar issues exist as for the RB211 retrofit option i.e. age of plant. SCR for the reasons stated above is also not a viable option at this point in time. Decommissioning these units and entering into commercial agreements, when these units are critical to the operation of the NTS, with high running hours, is not economic.

As part of our IPPC Submission, we propose to replace a third unit at Peterborough and Huntingdon on economic grounds. In Appendix 4 we provided a cost benefit analysis to support this decision.

Incorrect assumptions / misunderstandings

Within the consultants' reports there are a number of assumptions made that are incorrect, the process to date has unfortunately not provided the opportunity to clarify these points. The majority of the key issues we address in the main body of this response. In the interest of all parties we clarify the remaining points in Appendix 5.

Kirriemuir

As part of our submission we proposed replacing one MCP unit at Kirriemuir, which provided some construction efficiency and was intended to alleviate a potentially congested outage programme. Since our submission and based on our contributions, alongside other stakeholders, we have secured a derogation for compliance with the MCP legislation until 2030. This is a great result and will enable us to plan the MCP works in a more efficient manner and alleviate what would have been a potentially congested outage programme. Following this decision, the imperative to complete the works at Kirriemuir is not as strong, therefore we are able to wait to the 2018 reopener to put forward a complete MCP plan when greater certainty will exist.

Summary

As previously noted, in our view Ofgem's minded to position is not in the interests of consumers and users of the gas transmission network, as it creates significant regulatory uncertainty in relation to this critical IED investment programme. The regulatory uncertainty created by the proposed ex-post regulation in 2018 will lead to investment decision delays with more works being scheduled for later in the programme. This approach is therefore likely to reduce bundling opportunities, for example at Peterborough and Huntingdon, and lead to less efficient delivery, which will ultimately increase costs to consumers.

In terms of the questions raised in Ofgem's consultation letter we do not agree with the Penspen and Poyry conclusions. Through the combination of our original submission and this response, we hope Ofgem now has all the information they should require to make a decision.

Although we believe it is prudent to park the replacement works at Kirriemuir and revisit the MCP programme at the 2018 re-opener window, the following outputs are appropriate for ex-ante funding during the RIIO-T1 period:

LCP Element

- Kirriemuir – rewheel and derate Unit E
- Moffat – retained operational capability under 500 hours (asset health expenditure Units A&B)
- Carnforth – decommission Unit A, site reconfiguration, retained operational capability under 500 hours Unit B (asset health expenditure)
- Hatton – three replacement units in construction
- Warrington – retained operational capability under 500 hours (asset health expenditure Units A&B)
- Wisbech – change out of maxi Avon (Unit A) for an Avon, retained operational capability under 500 hours Unit B (asset health expenditure)

IPPC4 Element

- St Fergus – two replacement units commissioned
- Peterborough – two replacement units commissioned
- Huntingdon – two replacement units commissioned

We are committed to work with Ofgem over the coming weeks to reach an agreement on the essential elements, where we need regulatory certainty to avoid increased costs to consumers and delivery risk.

If you would like to discuss any aspect of our response, please do not hesitate to contact Martin Watson (martin.watson@ nationalgrid.com, 01926 655023) in the first instance.

Yours sincerely,

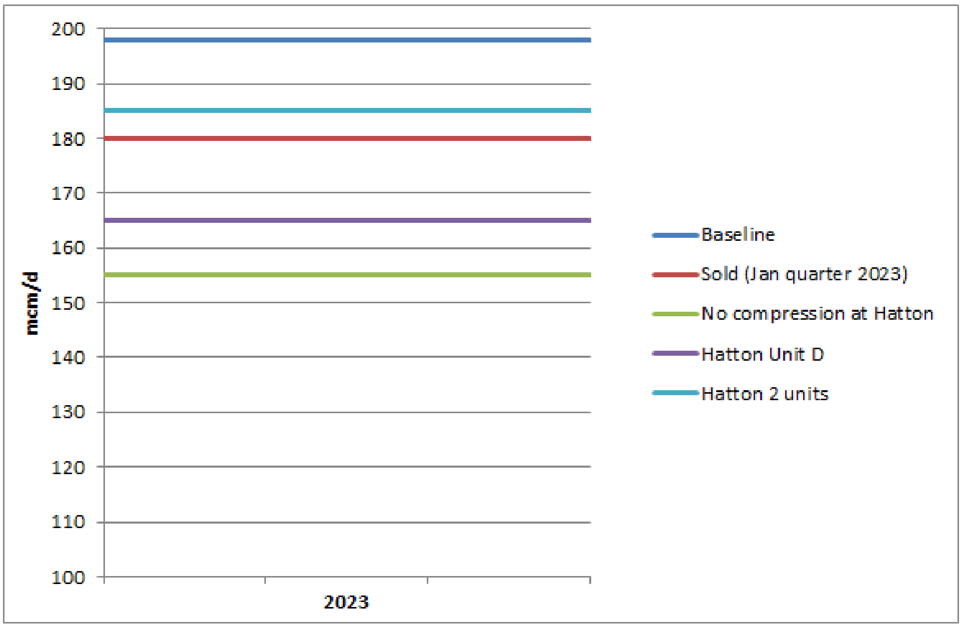
Mark Ripley
Director, UK Regulation

Appendix 1 – CBA Hatton need case

At Hatton we are proposing to replace the existing three large existing gas turbine units affected by the LCP element of IPPC with three medium sized gas turbine units. This is in addition to the 35 MW electric drive (Unit D) we are currently commissioning as part of IPPC Phase 2. In summary, we are proposing to:

- Replace one existing unit to provide additional capability when operated in parallel with unit D to predominantly cover high Easington area flow – we anticipate installing a 15.3 MW gas unit
- Replace two existing units to provide resilience to unit D, the largest unit on site – we anticipate installing two 15.3 MW gas units
- Decommission the three existing RB211s

In terms of entry capacity obligations, the Hatton compressor site is required to support high flows from the Easington area. The total capacity obligation within the Easington area is 198 mcm/d (2176 GWh/d) and in 2023 (January quarter) 91% of this obligated capacity is sold. The graph below shows the capability in the Easington area based on different compression capability at Hatton. The analysis is based on a 395mcm/d, i.e. a cold but not peak day and so can be considered likely to occur on a number of days in a cold winter.



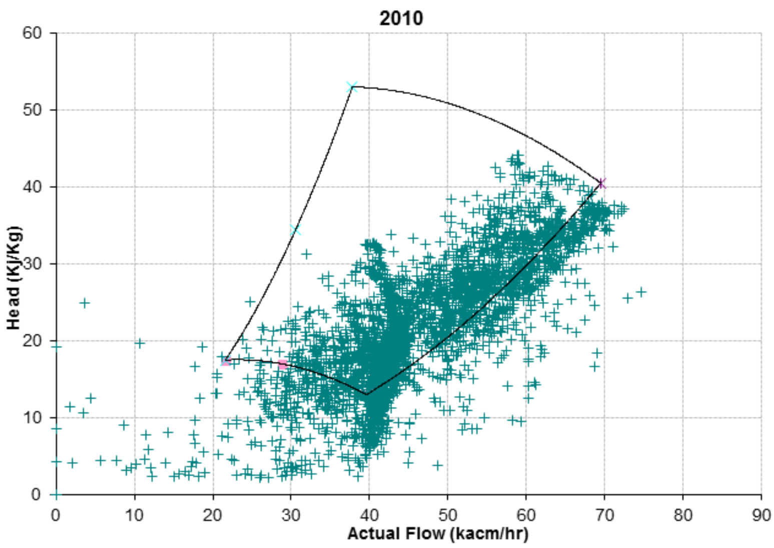
From the above it can be seen that if users choose to use the capacity rights which they have bought and we do not install a second unit at Hatton, we would need to buy back the capacity that we could not deliver. In this case we would need to buy back 15 mcm/d[1] and based on the constraint cost used for the RIIO-T1 incentive scheme development, the daily cost in 09/10 prices would be £0.98m per day. The UK would also be deprived of 15 mcm of gas on a high demand day, which would need to be delivered via alternative sources. Based on the unit cost allowance for a 15 MW compressor the 09/10 capital cost would be [redacted] with a nominal design life of 40 years. The table below shows that

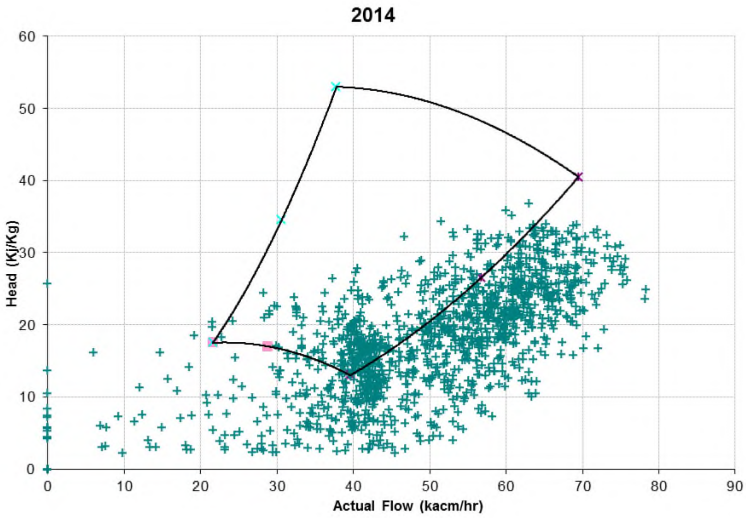
[1] This assumes that we would not need to buy back through the space otherwise this would require us to buy back 35mcm/d at an indicative cost of £2.29m per day (on the same basis as outlined above).

the breakeven point is approximately [redacted] days of constraints within the 40 year asset life. As noted above we have sold capacity for a full quarter in 2023 alone, therefore although the table only shows the costs for a maximum of 50 days, the total cost could be significantly higher. It should also be noted that once a constraint has been experienced, depending on the number of available players, the daily constraint cost could increase considerably, as would the likelihood of having to "buy through the space".

Capital allowance for 15.3 MW gas compressor (£m, 09/10 prices)	Constraint duration over 40 years (number of days)	Constraint Cost (£m)
[redacted]	0-10	£0-9.8m
	10-25	£9.8m-£24.5m
	25-50	£24.5-49.0m

In addition to the constraint analysis, below we show the recent operational data (pressure and flow) with the Unit D operating envelope overlaid. The data shows the points at which the compressor has been required to operate at based on supply and demand patterns in 2010 (a relatively cold winter) and 2014 (a relatively mild winter). Any point outside of the enclosed envelope would need to be covered by another unit.





Based on the required duty, there would have been circa 600 and 1075 hours of operation that could not have been met at Hatton without additional compression in 2010 and 2014 respectively. The analysis excludes operating points associated with compressor start up. Given the combination of the normal operating duty being well in excess of 500 hours and the potential constraint costs, we conclude that the cost / benefit of installing one new unit is robust.

In accordance with our Planning Code, we have also proposed to replace two further units to provide resilience for the loss of the largest unit on the compressor site. As we anticipate Unit D being required to operate for significantly more than 500 hours on a regular basis, to cover any prolonged outage for example due to mechanical failure, we would need more than 500 hours of back up, in light of this we have not pursued derogations on the existing units to meet this requirement.

Appendix 2: RB211 DLE Retrofit Emissions Assessment

To understand the potential suitability of a RB211 retrofit we undertook a study to investigate at what duty points the RB211 would need to operate and then assessed its emission performance at these points. Below is a description of the study assumptions and the associated results.

Assumptions

1) The emissions compliant range of the RB211 DLE retrofit (as supplied by [redacted]) is 100% to 70% load (i.e. 25.3MW to 17.5MW)

2) The 35MW VSD can operate in parallel with the RB211 DLE retrofit. The VSD and the RB211 DLE retrofit can also operate singly.

3) Load sharing rules are:

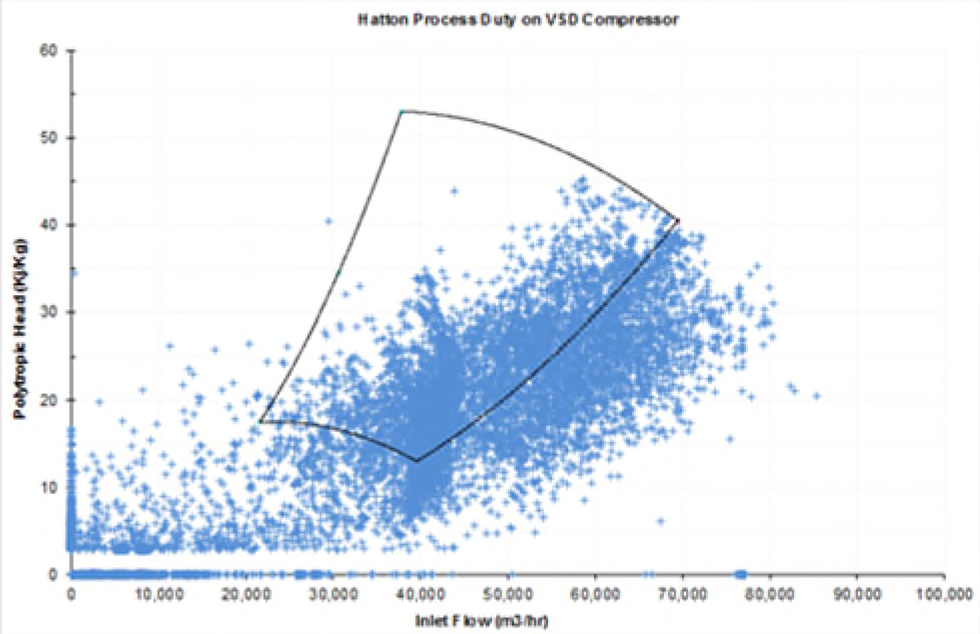
    a. The VSD is used in preference to the RB211 due to its superior emissions, efficiency and operating capability

    b. Load sharing between the VSD and RB211 is optimised to allow both units to operate as efficiently as possible

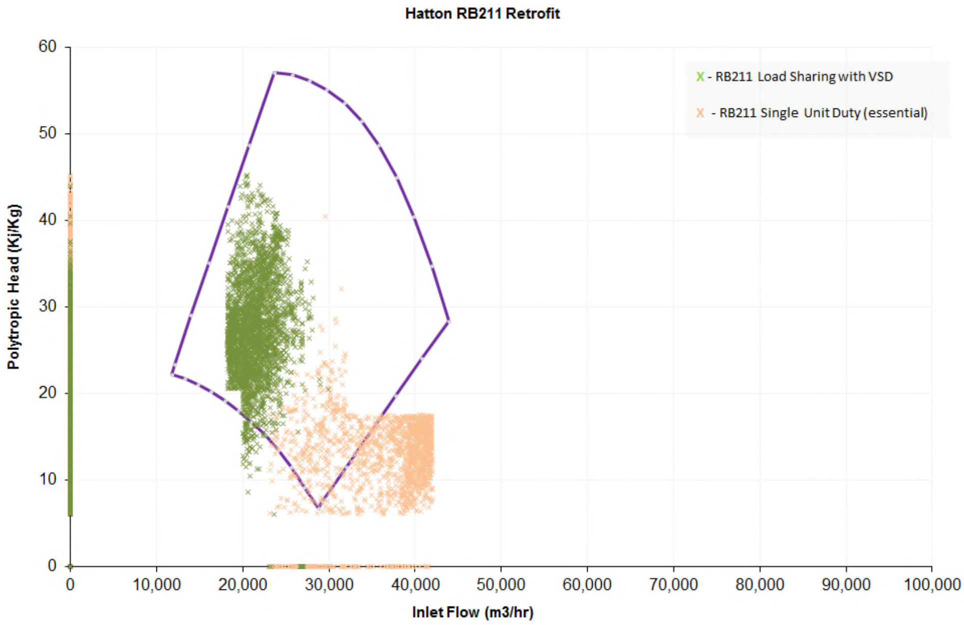
    c. RB211 single operation is used when the load is below the capability of the VSD

4) The analysis is based on historic station duty from 2010 to 2014.

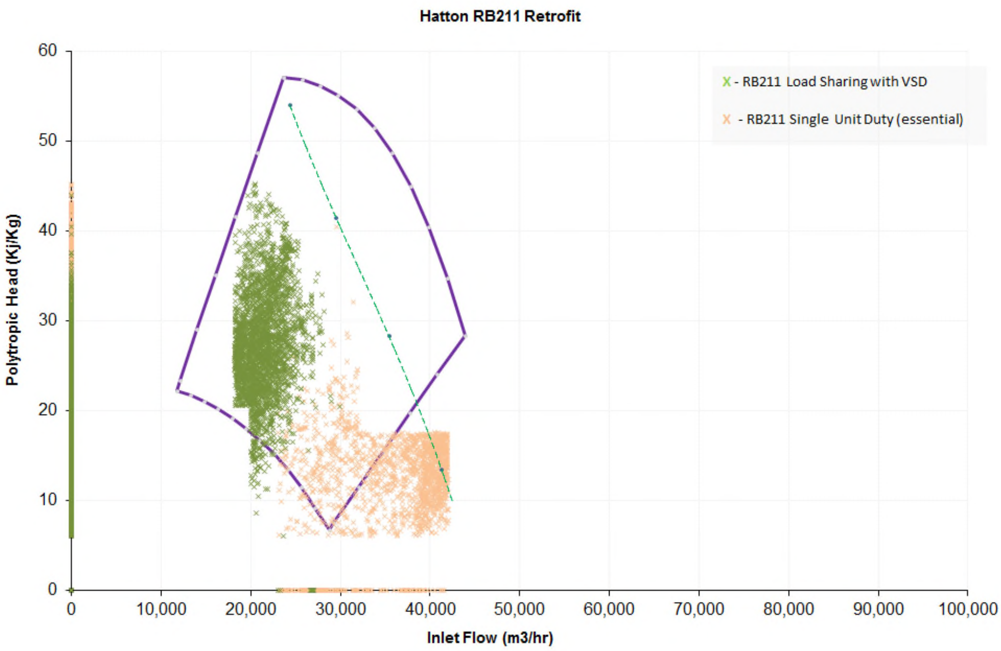
The chart below shows the station duty on the 35MW electric VSD envelope – no load sharing has been applied.



The operating points outside of the VSD envelope would need to be covered by another unit, i.e. the RB211 retrofit. Some of these points (green in the diagram below) would be covered by parallel operation and some of these points (orange in the diagram) below would be covered by single operation.



However, the RB211 DLE retrofit is only compliant with the CO emission limit specified in the IED at above 70% load and the diagram below shows the 70% load line. It can be seen that the vast majority of the data points fall outside of this range and therefore the RB211 retrofit is not considered BAT for Hatton.



Appendix 3: Emissions Data for Candidate IPPC4 sites

Site	Turbine Unit	2009 NOx (t)	2009 CO (t)	2010 NOx (t)	2010 CO (t)	2011 NOx (t)	2011 CO (t)	2012 NOx (t)	2012 CO (t)	2013 NOx (t)	2013 CO (t)	2014 NOx (t)	2014 CO (t)	Average NOx (t)	Average CO (t)
Alrewas	A	1.503	6.150	7.919	23.398	1.696	4.970	1.292	4.036	0.658	4.401	0.370	1.984	2.240	7.490
	B	0.031	0.604	1.390	7.046	0.984	4.140	1.109	4.538	0.370	1.923	0.058	0.413	0.657	3.111
Cambridge	A	0.072	1.030	0.756	3.651	0.018	0.427	0.132	1.190	0.210	1.893	0.049	0.482	0.206	1.446
	B	0.062	0.757	0.090	1.335	0.012	0.327	0.036	0.565	0.019	0.250	0.205	1.528	0.071	0.794
Chelmsford	A	0.005	0.194	0.009	0.262	0.024	0.324	0.017	1.398	0.046	0.771	0.002	0.081	0.017	0.505
	B	0.022	0.600	0.140	0.789	0.019	0.199	0.046	1.482	4.495	25.515	0.031	0.343	0.792	4.821
Diss	A	0.371	3.171	2.379	18.519	0.003	0.088	0.027	0.452	6.410	26.873	0.281	1.906	1.579	8.501
	B	0.217	1.325	0.019	0.169	0.019	0.271	0.016	0.184	1.715	11.379	0.000	0.000	0.331	2.221
	C	0.000	0.000	0.359	2.491	0.010	0.271	0.029	0.260	0.212	2.131	0.017	0.354	0.105	0.918
Huntingdon	A	12.711	27.182	30.139	67.448	12.538	29.130	6.138	14.483	23.821	71.729	18.304	44.973	17.275	42.491
	B	15.449	38.008	14.199	36.138	0.430	2.343	4.621	15.813	22.898	89.890	10.273	23.030	11.312	34.204
	C	10.601	28.570	33.992	98.467	5.037	21.252	0.036	0.209	2.291	7.071	6.106	13.637	9.677	28.201
Kings Lynn	A	0.005	0.067	0.000	0.000	0.000	0.000	0.091	0.816	0.014	0.098	0.000	0.000	0.018	0.164
	B	0.028	0.336	0.125	0.518	0.076	0.291	0.036	0.272	0.526	2.703	0.052	0.310	0.140	0.738
Kirriemuir	A	0.143	0.712	6.894	10.149	6.020	13.665	8.155	18.949	7.983	14.119	1.715	5.760	5.152	10.559
	B	0.191	0.914	4.023	6.634	0.236	1.654	6.102	15.657	0.066	0.542	0.150	0.464	1.795	4.311
	C	1.657	2.543	3.392	8.077	0.021	0.177	0.000	0.000	0.035	0.255	0.008	0.170	0.852	1.870
Peterborough	A	19.742	36.912	41.014	70.629	35.206	72.153	33.418	80.558	53.697	80.993	45.617	63.935	38.115	67.530
	B	29.731	35.172	40.412	51.219	18.615	28.185	29.267	42.165	46.603	93.647	22.381	40.573	31.168	48.494
	C	29.807	55.045	29.170	72.591	16.191	35.297	34.085	64.497	19.854	40.485	25.527	55.122	25.772	53.840
St Fergus	1A	16.330	37.091	20.360	55.242	27.585	68.577	30.131	67.544	47.758	105.967	26.034	73.979	28.033	68.066
	1B	10.393	35.836	11.598	40.416	17.005	41.444	6.463	15.821	2.445	6.268	0.219	0.664	8.021	23.408
	1C	15.501	46.856	2.509	10.389	9.207	39.288	7.127	24.296	13.177	45.777	19.358	77.358	11.147	40.661
	1D	22.019	53.792	20.337	51.276	32.860	98.136	37.973	165.183	8.689	31.604	18.378	59.161	23.376	76.525
	2B	6.933	45.359	7.849	54.078	6.871	57.281	1.298	4.316	1.286	3.081	0.529	2.322	4.128	27.740
Wormington	A	2.778	6.752	31.605	69.280	45.151	69.137	4.822	12.196	0.122	0.348	0.130	0.969	14.101	26.447
	B	1.558	2.942	15.436	28.447	46.469	50.461	0.781	1.355	0.240	0.544	0.185	1.165	10.778	14.152
	C	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	NA	NA	0.000	0.000

IPPC3 Replacement

IPPC4 Proposed replacement

Appendix 4 – CBA Peterborough / Huntingdon

Peterborough and Huntingdon are very similar sites, therefore for the purposes of this CBA we only discuss Peterborough, but the results are equally as applicable to Huntingdon. At Peterborough there are three medium sized compressors and we have secured funding under IPPC3 to install one new unit. In our submission we have proposed to install a further unit under the continuing requirements of IPPC and this has been agreed with the Environment Agency as part of the Network Review process. This recognises that even though we will be installing one new unit under IPPC3, Peterborough will still be one of the most polluting sites, as shown in the emissions data within Appendix 3. Two units are required at both sites to meet our 1 in 20 obligations in the South East and South West exit zones.

All of the existing units on the site will need to be addressed as part of the Medium Combustion Plant Directive, which requires units that cannot meet the relevant emission limits, to either close or operate under a limited hours derogation by 2030. In 2030, the newest of the existing units on the site will be 52 years old and in accordance with our Planning Code, replacement is required at some point to maintain resilience to the loss of the largest unit on site. We therefore undertook a cost benefit analysis to determine the optimum time to replace one of the remaining three units. Due to construction efficiencies the optimum time to replace the third unit, as shown in the table overleaf, is at the same time as undertaking the IPPC3 and IPPC4 works. This provided a financial benefit of £18.2m over the next best option, which was to overhaul the newest existing unit and then replace in 2030.

This approach also provides the additional benefit of allowing the units to be operated in a manner that shares the operating hours across the units, as per the current mode of operation, thus maximising the life of each of the units. We are also able to reduce our emissions earlier than waiting until 2030 and maximise the use of system outages at these critical compressor stations.

It is also worth noting that whilst the presented CBA focusses predominantly on the investment cost, i.e. replacement, asset health and decommissioning, we also examined a number of other factors. These are:

- Running hours
- Amount of gas vented
- Fuel usage
- European Emission Trading Scheme
- Impact on System Operator Incentives – shrinkage, green-house gas emissions

However, when comparing the options if the compressor was still available, the assumption was that the running hours would not be different between the options. We also had no evidence that new replacement machines would have any meaningful impact on the opex factors e.g. fuel usage.

Therefore the only material difference between the options was the site capex.

In terms of the stakeholder engagement we “ranged” the site capex for commercial confidentiality reasons, but at no time did stakeholders suggest that this impacted their decision making capability.

Table redacted

Appendix 5 – Incorrect assumptions / misunderstandings

Penspen: Independent Review of National Grid's IED Investments: Ofgem Submission

4.3.5 Hatton

Further Discussion of Option 4
In terms of the proposed option 4 replacement it will not provide the same system capability as the existing units.

Although factually correct, in practical terms the capability will be the same. This is because the 35 MW electric drive is in the process of being commissioned. Therefore the proposed solution provides 50 MW of power (electric plus one gas) with 30 MW in reserve (two gas). Previously the total compressor power of the station would have been 50MW, with 25 MW in reserve.

5.5
Item 2 in Section 5.3 above identified an allowance of £20.1m decommissioning costs for fifteen units. The allowance for decommissioning appears to be based on the 2014/15 budget prices provided by AFW, ref estimates 2, 3 and 4 in NGGT Appendix II. NGGT appear to have used the budget price plus the identified risk allowance. According to the presentation made to Ofgem on 3 June 2015, NGGT have added circa 4% (estimated by interpolation) of the budget cost to cover NGGT and Project Services costs. NGGT does not appear to have attempted to convert the 2014/15 budget prices to 2009/10 prices.

The above statement is factually incorrect as all prices have been converted to 09/10 prices and as stated in Appendix 1 of the submission, the NGGT and Project Services costs have been developed on an individual basis and therefore vary per project. These statements also appear in 5.6 and 5.7. A more detailed cost breakdown for each site is provided in a separate excel spreadsheet.

5.7
There is minimal information provided in the Appendices to identify what is exactly included under "Asset Health" as only the generic parts of the AFW estimate sheets have been included in NGGT Appendix II.

Whilst this is true, we have provided extensive information on the asset health works through the Q&A process.

5.9

"NGGT have not explained the significance of the ranges illustrated in the Holistic Assessment"

We have stated on page 68 of the Submission that the ranges serve no purpose other than to protect commercial confidentiality, as the main part of the document was a public consultation. The ranges use the values specified in the assessment criteria.