Waters Wye Associates

UK gas transmission system benefits from gas storage – an update to the initial report produced in 2007

A report for GSOG

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Executive Summary

In the context of the EU Framework Guideline on the harmonisation of gas transmission tariffs, discussions about the future European Network Code on this issue and an Ofgem review of the gas transmission charging methodology in GB, GSOG commissioned this study from WWA. The specific issue at stake is the way that gas transmission charging should be applied to storage facilities, particularly as regards the Transmission Owner (TO) charges which may be most affected by the new Network Code.

GSOG asked WWA to review and update our estimates of the transmission benefit which GB gas storage facilities bring to the NTS, in terms of avoided investment in additional gas transmission capacity. The update would be based on the analysis carried out by WWA in its storage benefits report for GSOG in 2007.

There are three key steps in this analysis:

- Evaluate the role which gas storage facilities play in GB gas supplies on a peak winter day for which the gas transmission system is designed;
- Identify the transmission investments which would be required to manage peak gas demands and flows if those storage facilities did not exist; and
- Convert those investments into a transmission benefit of gas storage, which can be expressed as an annual cost saving and/or an NPV.

The WWA 2007 storage benefits report utilised the Transportation Model (TM) to investigate the potential additional investment costs which would be incurred if, gas assumed to be provided by storage facilities on the peak day, was sourced from alternative entry points instead. Employing a number of alternative supply scenarios, WWA concluded that gas storage facilities provided substantial benefits (in terms of the avoided transportation infrastructure) to GB and quantified that those benefits could be in the range of £218m to £1,929m, as a capital cost, which equated to £24m to over £200m per annum. This could be compared with a TO Allowed Revenue figure for the NTS of £526m (in 2007/8 prices) for the 2007/8 Formula Year

In order to re-evaluate the findings from the WWA 2007 storage benefits report, it was necessary to redefine the supply merit order employed by National Grid to underpin its Transportation Model. The current supply merit order assumes that no MRS supplies are required to meet 1 in 20 peak day gas demand which, in turn, forms the basis for the determination of the LRMCs used by National Grid to derive NTS TO related charges.

In order to inform one of the supply merit order scenarios, as well as to justify modification of the merit order, WWA has carried out supply/demand correlation analysis based on historical flow patterns over the two most recent winter periods. The analysis shows a positive, albeit modest correlation between MRS supplies and demand, but more critically, a negative correlation between LNG supplies and demand. Furthermore, it is shown that on the peak demand day experienced over the period under investigation, MRS flows equated to 53% of available withdrawal capacity compared to a LNG equivalent measure of 20%. National Grid's most recent Winter Outlook report also suggests significant MRS withdrawals at peak. This provides a robust justification for a re-examination of the supply merit order currently employed within the TM.

Two scenarios were used to test the NTS CAPEX benefits which could be ascribed to storage. The first scenario, termed the Amended Base Case, translates the findings in the correlation analysis into relative peak day demand supply contributions, with LNG supplying 551.5 GWh and MRS supplying 783.2 GWh. The High Storage Case provides a more extreme scenario, with LNG supplies set to zero (placed below MRS in the merit order) and MRS supplies at 1334.7 GWh.

The two cases were tested to evaluate the benefits, in the form of CAPEX savings, which storage provides to the transmission system. As in 2007, no attempt has been made to assess any OPEX benefits, as the information required to carry out the analysis is only available to National Grid. As in 2007, the Cases were tested against a number of scenarios which were all based on the proviso that if storage did not exist, then flows into the system would have to be provided at alternative sources – termed storage replacement gas.

Using ten different supply scenarios, we have identified CAPEX benefits for each of the cases. Of these supply scenarios, nine were taken from the 2007 analysis, in order to provide an update to that report. A further scenario was examined which distributed the storage replacement gas equally across the entry points, but capped at their obligated entry capacity levels.

The results are provided in the form of annual savings, using the TM annuitisation factor, and measured against the two cases. The results for the Amended Base Case show a range of annual savings of £3m to over £197m with most concentration around the £40m to £65m range. The results for the High Storage Case show a range of annual savings of £6m to over £312m with most concentration around the £50m to £70m range.

In order to consider the impacts on prices of modifying the supply stack, the exit and entry capacity prices have been presented for each storage point and DN exit zone. The results show that removal of the price floor, inherent within the transportation model to exclude negative charges, leads to dramatic price variations. However, in the Amended Base Case, even in those scenarios where the price floor remains intact, exit capacity charges at all storage points either reduce, or remain the same (where they are already set at the price floor). In terms of entry capacity charges, the results are more inconsistent across all cases, with some storage sites seeing price increases and others price decreases. This is due mainly to the fact that at many of the storage points current charges are at the minimum (floor) levels.

The review of alternative charging mechanisms in GB power and GB gas distribution networks provides helpful examples of regimes which employ negative charges, or credits, as well as, in the case of other EU gas markets, more significant capacity charging discounts for storage related flows. These case studies can be used to support initiatives focused on improvements to the NTS charging methodology to the benefit of storage users.

Based on our analysis, we believe that we have gathered sufficient evidence to support modification of the supply stack in National Grid's Transportation Model. In addition, and independent of this change, there is further evidence, based on our CAPEX savings analysis, to recommend the possibility of introducing "bespoke" charging arrangements for storage related transmission charges.

In summary, our recommendations are as follows:

i) Consider proposing changes to the supply merit order;
ii) Consider potential for negative capacity charges or simply removing all transmission charges currently applied at storage;
iii) Consider application of ex-ante credits for storage flows akin to those applied at DN entry points;
iv) Consider potential for the application of a “corrective” ex post credit to storage users delivering gas on peak days;

In order to seek “special treatment” for storage, industry will need to be convinced that storage, firstly, **can** be treated differently and secondly, **should** be treated differently to other system points. Certainly, WWA believe that by the very fact that the EU Tariffs Framework Guideline makes special provision for the treatment for storage (and only storage) then it meets the first test. Further, the evidence presented in this report goes someway to meeting the second.

1. Introduction

In December 2013 the European Commission determined that the framework guideline on rules regarding harmonised transmission tariff structures for gas, produced by ACER, reached its objective to contribute to effective competition and efficient functioning of the gas wholesale markets as well as non-discriminatory third party access. On this basis it invited ENTSOG to submit a network code in line with the framework guideline by 31 December 2014.

Contained within the framework guideline there is direct reference to the treatment of tariffs for services associated with supporting storage flows:

"The Network Code on Tariffs shall specify that, in setting or approving tariffs for entry and exit points from and to gas storage facilities, NRAs shall consider the following aspects:

- *The benefits which storage facilities may provide to the transmission system*
- *The need to promote efficient investments in networks*

NRAs shall also minimize any adverse effect on cross border flows."

Further to the EU developments, the GB energy regulator Ofgem has initiated a review of transmission charges, partly in response to the EU tariff code and partly due to the perceived need to carry out a periodical review of charges and the underlying methodology.

As a result of these two initiatives, GSOG has commissioned WWA to revisit the analysis it carried out in 2007 to evaluate the benefits which gas storage provide to the GB National Transmission System.[1]

As well as updating the estimate of benefits, this report considers potential alternative transmission charging methodologies and examines the approaches taken in other markets, including the GB electricity market and EU gas markets as well as the recently modified approach adopted by GB DNs in relation to embedded entry points.

[1] WWA, UK Gas Transmission System Benefits from Gas Storage – A report for GSOG, September 2007

2. Overview of National Grid's Transportation Model

The National Grid Transportation Model (TM) contains a database of all pipes that form the NTS, populated with assumed levels of flow at each entry and exit point on the NTS for the 1 in 20 peak day. It comprises:

- The **Transport Model** that calculates the Long Run Marginal Costs (LRMCs) of transporting gas from each entry point (for the purposes of setting NTS Entry Capacity Prices) to a "reference node" and from the "reference node" to each relevant exit point.

- The **Tariff Model** that adjusts the LRMCs to either maintain an equal split of revenue between Entry and Exit users (where entry prices are used to set auction reserve prices) or to recover a target level of revenue (where exit prices are set as administered rates).

The prices for each Gas Year are calculated using the relevant year's 1-in-20 peak day Base Case supply and demand data and network model, noting that the reserve prices calculated for entry points are set by adjusting the supply flows in the Base Case data to reflect the obligated level of Entry Capacity at each NTS Entry Point as set out in National Grid's GT licence in respect of the NTS.

The TM calculates a proxy for the LRMC (which is expressed in km) at each entry or exit point, which when multiplied by the Expansion Constant, represents the capital investment cost in additional pipe and/or compression which would be incurred (or saved) by an incremental change in supply or demand respectively at that point.

The Expansion Constant, expressed in £/GWh/km, represents National Grid's estimate of the capital cost of the transmission infrastructure investment required to transport 1 GWh over 1 km in order to increase the peak day flow at an entry or exit point. It is derived from the projected cost of an 85bar pipeline and compression for a 100km NTS network section. The 100km distance was selected as this represents the typical compressor spacing on the NTS. The value used within the current version of the TM is £2918/GWh/km (which is approximately equal to £8.55 per unit of peak day capacity required to transport 1 therm over 100 km).

The TM, as supplied to users, has a constraint which ensures that both the resultant entry and exit charges must be greater than zero (plus a *de minimis* charge) so the output exit and entry prices are always 0.0001 p/kWh/d, or greater. Additionally, for exit charges, it contains an algorithm which ensures that the forecast level of exit capacity charges match back to a given Allowed Revenue figure which is to be collected from exit charges.

When running the TM, the first step is to set supply equal to the forecast level of demand for the peak day for the particular year being considered. The obligated level of capacity to be offered at each of the entry points is set out in National Grid's GT licence in respect of the NTS. As the total of these obligated levels is considerably greater than forecast peak day demand, the level of supply at each entry point is amended according to the prevailing charging methodology applicable at the time the model is run.

When the original WWA 2007 analysis was undertaken, the Base Case peak day flows in the Transportation Model consisted of substantial amounts of gas being supplied by underground storage sites. Since then, the methodology has been amended such that the supply merit order (which is used to reduce supply levels to match forecast demand) now assumes very little peak day supply from storage sites, other than Rough.

2.1 Overview of original WWA 2007 analysis

In 2007 WWA produced a report which quantified the potential benefits provided by gas storage facilities within the UK. The report utilised the TM to investigate the potential additional investment costs which would be incurred if, gas assumed to be provided by storage facilities on the peak day, was sourced from alternative entry points instead, which in turn is likely to require increased gas transmission capability on other parts of the NTS.

As noted above, the TM as supplied to users, has a constraint which ensures that both entry and exit charges must be greater than 0.0001 p/kWh/d. If that constraint is removed, the TM can be used to calculate a Base Case Value, which is a proxy for the total capital investment in the NTS. This is derived by adding together the results of multiplying the peak day flows in the TM at each entry or exit point by the LRMC at that point (calculated by the Transport Model part of the TM) and also by the Expansion Constant within the Model.

Using this approach, the 2007 analysis derived a Base Case Value of the NTS system of £2.958bn (which was of the same order of magnitude as the Regulated Asset Value (RAV) of the NTS as set by Ofgem as part of the 2007/2012 price control review). WWA noted that it was not important to match the Base Case Value back to the RAV exactly, as the subsequent analysis was based on examining variances from the initial Base Case Value.

The 2007 approach noted that the Base Case Value can be converted to an annual cost of capital recovery through multiplying by the Annuitisation Factor supplied by National Grid within the Model. The default value of 0.10772 was the Annuitisation Factor used in the TM (and was given in National Grid's GT Licence for the NTS at the time). As noted above, the basis of the analysis was to investigate changes to the annual cost of running the system, not in the absolute value, therefore increases or decreases in annual system costs were calculated by multiplying the difference between the Base Case Value of the NTS and a Scenario Value (described below) by the Annuitisation Factor.

WWA's analysis was based on an assumption that if GB storage were not to exist, then additional gas from outside the UK NTS would need to be delivered through existing terminal entry points in order to meet 1 in 20 peak day demand. The benefit which storage provided to the system, by moving the entry of gas from the storage sites on the 1 in 20 peak day to existing terminal entry points, was calculated under a number of scenarios. The TM was run and the Scenario Value calculated for the NTS under each for each of these scenarios. The Scenario Value was then compared to the Base Case Value. If the Scenario Value was higher, then it showed that the NTS would need further investment to accommodate the revised flows of gas and provided a quantification of the saving which storage sites brought to the system. If it were lower, then it demonstrated that the existence of storage was a net cost to the system and provided a quantification of that cost.

Note that this form of analysis excluded any operating costs incurred through the provision of compression as the TM is limited to only evaluating the capital investment required for the transportation of gas. The 2007 analysis noted that it is likely that where a capital investment is identified, it follows that additional annual costs would also be required to supply the fuel gas for operating the additional compression and as such the analysis undertaken by the approach was likely to underestimate the true value/benefit of storage to the NTS.[2]

The report considered likely alternative entry points for additional gas were storage sites unable to deliver gas onto the system on the 1 in 20 peak day. Due to the decline in the southern UKCS and Morecambe Bay, any entry points that were solely connected to those areas were excluded. The report suggested that the additional flows could be at:

- Bacton, via the Interconnector or the BBL
- Easington, via Langeled
- Teesside, via Excelerate LNG
- St Fergus (additional supplies from Norway)
- Isle of Grain LNG
- Milford Haven LNG

As a set of baseline scenarios, the report considered all ‘storage replacement’ gas entering at only one of the above six sites. This provided an upper bound to the benefit brought by storage to the system.

Additionally, three more probable scenarios were modelled, which assumed that the storage replacement gas is sourced through a combination of the above six terminals:

1. storage replacement gas is sourced in equal volume at each of the terminals;
2. storage replacement gas is sourced in equal volume from the top three terminals only, on the basis that the LNG entry points are not sized to provide swing and St Fergus provides only associated gas which cannot provide swing; or
3. storage replacement gas is sourced in equal volumes only via Bacton and Teesside, assuming the Langeled line is delivering flat gas and has no spare capacity to provide swing.

WWA’s original 2007 analysis concluded that gas storage facilities provided substantial benefits (in terms of the avoided transportation infrastructure) to GB and quantified that those benefits could be in the range of £218m to £1,929m, as a capital cost, which equated to £24m to over £200m per annum. This can be compared with a TO Allowed Revenue figure for the NTS of £526m (in 2007/8 prices) for the 2007/8 Formula Year.

[2] Admittedly this is an overly simplistic representation of the network and operational costs will depend not only on the individual location of the facilities, but also their geographical concentration. Further, given storage sites inject as well as deliver, the SO costs associated with meeting bi-directional flow requirements would need to be considered.

3. Updated transmission benefits analysis

This section sets out analysis carried out by WWA to evaluate the benefits which gas storage facilities provide to the UK. As in 2007, the analysis focuses on the transmission CAPEX savings which might be reasonably assumed to be provided by storage.

3.1 Updated modelling assumptions

As noted in Section 2, in 2007 the TM assumed a significant amount of gas being supplied at storage sites in order to ensure that aggregate levels of supply matched the forecast level for peak day demand.

Since the 2007 analysis, the assumptions applied to ensure a supply and demand within the TM have been amended.[3] This means that the base case flows assumed within the current version[4] of the TM differ from those assumed in 2007. The differences are shown in table 1.

Table 1 – Base case flow assumptions 2007 vs 2014

Source	Original TM assumption Base Case flows[5]		March 2014 QSEC auction TM assumptions Base Case flows[6]	
	GWh	% of total	GWh	% of total
Bacton	1492.5	26%	1780.0	29%
Easington (less Rough)[7]	629.8	11%	863.9	14%
Isle of Grain LNG	140.8	2%	542.2	9%
Milford Haven	0	0%	792.5	13%
St Fergus	1232.7	21%	1107.9	18%
Teesside	341.1	6%	445.1	7%
Other Terminals	579.3	10%	148.6	2%
LNG Storage[8]	526.1	9%	0	0%
Underground Storage	844.8	15%	455.0	7%
TOTAL	**5787.1**	**100%**	**6135.1**	**100%**

In particular, LNG importation terminals now account for 22% of modelled peak day flows in the Base Case used by National Grid, as compared with just 2% in the corresponding

[3] In 2009, NTS GCM 16 amended the assumptions used to match supply and demand within the TM. This involved amending both the merit order used to achieve the supply/demand match within the model, plus the source of the supply data used.
[4] The modelling within this analysis has been carried out using the latest version of the TM (to accompany the March 2014 QSEC auction) issued by National Grid on 29/01/14.
[5] As per the TM produced by National Grid on 29 November 2006 in relation to Charging Consultation NTS GCM01.
[6] Based on 2013 TYS Gone Green peak flow assumptions for 2016/17.
[7] Within the TM, the Easington ASEP includes Rough, but we have included an assumption of 455 GWh/d for Rough within Underground Storage.
[8] LNG Storage was made up of the four sites owned by National Grid at the time; Avonmouth, Dynevor Arms, Partington and Glenmavis. Avonmouth is the only site currently operated by National Grid, but is anticipated to cease operation in 2018.

Base Case used in the 2007 analysis. By contrast, storage flows contribute only 7% of modelled peak day flows in the current TM Base Case assumptions, as against as much as 24% under the original 2007 Base Case assumptions.[9]

The approach undertaken within the original 2007 analysis was based on replacing storage flows of 1370.9 GWh (LNG storage of 526.1 GWh plus underground storage of 844.8 GWh from the second column in the table above) with gas from alternative entry points. Looking at table 1 above, column 3 shows that the only gas which is now assumed to be flowing from storage sites at peak is 455 GWh, i.e. Rough.

As only Rough is allocated supply in this set of Base Case assumptions there is no opportunity to investigate alternative sources of supply in order to value the benefit (in terms of avoided investment cost) which storage sites provide. Moreover, there is considerable evidence (which we set out below) to the effect that the current TM supply stack no longer provides an accurate representation of peak day gas supplies into the GB market.

As WWA noted in our 2013 analysis relating to exit charges applicable to gas storage in NW England[10], we propose adjusting the TM supply stack to be more reflective of actual flow patterns in order to provide a sound set of Base Case assumptions for further analysis of the benefits which storage facilities provide in terms of avoided infrastructure cost.

NTS GCM 16 consultation and the current supply assumptions within UNC TPD Y2.5.1(c)

Following the implementation of NTS GCM16, the following supply stack order is used within the TM to match supply to forecast peak demand:[11]

1) Beach
2) Interconnectors
3) LRS
4) LNG
5) MRS
6) SRS

The 2013 TYS Gone Green peak forecasts for 2016/17 are used as the basis of the supply data included within the TM issued to underpin the March 2014 QSEC auction. However, the total of these peak supply forecasts (8162.6 GWh) is in excess of the peak day demand figure of 6135.1 GWh and therefore, adjustments have been made (in accordance with the prevailing methodology set out in Section Y of the Transportation Principal Document of the UNC) to ensure that supply is reduced to match demand. This means that when the merit order is applied, peak day demand is reached before any MRS or SRS sites are assumed to be flowing.

[9] Note that within the current TM Base Case assumptions, the only storage facility which is assumed to be flowing to meet peak day demand is the Rough site.
[10] WWA, Examining the possibilities for developing alternative NTS Exit Capacity Charges to be levied at GB storage facilities – a report for GSOG, June 2013.
[11] Note that the Charging Methodologies are now included within Section Y of the UNC TPD, so any change to the merit order above (included as UNC TPD Y2.5.1(c)) would require an amendment to the UNC.

Table 2 shows how the 2013 TYS Gone Green Peak forecasts for 2016/17 have been adjusted to create the Base Case used within the model, as supplied by National Grid, to match the total level of supply to the forecast level of peak demand of 6135.1 GWh/d for the base year of 2016/17:

Table 2 – Base case flow assumptions for QSEC auctions 2014

Source	2013 TYS Gone Green Peak assumptions for 2016/17	March 2014 QSEC auction TM assumptions	% of Gone Green Peak
	GWh	GWh	
Bacton	1780.0	1780.0	100%
Barrow	77.2	77.2	100%
Easington (incl Rough)	1318.9	1318.9	100%
St Fergus	1107.9	1107.9	100%
Teesside	521.9	445.1	85%
Theddlethorpe	71.3	71.3	100%
Onshore (Wytch Farm)	6.1	0	0%
Burton Point	0	0	0%
Isle of Grain LNG	644.6	542.2	84%
Milford Haven	942.5	792.5	84%
MRS	1692.2	0	0%
TOTAL	**8162.6**	**6135.1**	**75%**

WWA note that National Grid has used the Gone Green Peak forecasts as the basis for the Base Case supply assumptions within the TM. We have considered whether using the Slow Progression Peak forecasts would produce different results. The following table shows a comparison between the 2013 TYS Gone Green Peak forecasts for 2016/17 and the 2013 TYS Slow Progression Peak forecasts for 2016/17.

Table 3 – Gone Green base case vs Slow Progression base case

Source	2013 TYS Gone Green Peak assumptions for 2016/17	2013 TYS Slow Progression assumptions for 2016/17	% difference (SP-GG)/GG
	GWh	GWh	
Bacton	1780.0	1801.7	1%
Barrow	77.2	79.8	3%
Easington (incl Rough)	1318.9	1316.7	0%
St Fergus	1107.9	1121.2	1%
Teesside	521.9	541.0	4%
Theddlethorpe	71.3	64.6	-9%
Onshore (Wytch Farm)	6.1	2.2	-63%
Burton Point	0	0	0%
Isle of Grain LNG	644.6	644.6	0%
Milford Haven	942.5	942.5	0%
MRS	1692.2	1692.2	0%
TOTAL	**8162.6**	**8206.6**	**1%**

Given there is very little difference between these two sets of peak day assumptions, we have concluded that the use of either Gone Green or Slow Progression cases as the demand measure will not materially affect the results. Although there can be a material and growing difference between the two scenarios in terms of annual gas demand, the two sets of peak day gas demands and supplies are, in fact, remarkably similar.

We have adopted the Gone Green scenario as the starting point for adjusting to a more representative peak supply stack, since this is generally seen as a policy 'base case' by government departments and regulators.

3.2 Alternative supply merit order

In the WWA Exit Capacity report produced for GSOG in 2013, we tested the following hypothesis:

"Given that gas storage sites are embedded within the UK network and responsive to UK demands that they will deliver gas at times of high UK demand. In contrast, other sources of supply which have access to alternative markets, such as interconnectors, LNG and some beach gas will more likely have a lower probability of supply delivery during periods of high UK demand. It would be reasonable to assume, for example, that during periods of high demand in UK, other NW European countries which themselves are import dependent, will face similar relatively high demand levels – given demand is weather driven. For this reason, WWA proposes that a merit order which relegates storage to the end of the supply stack is not appropriate and alternative configurations should be tested."

Our analysis, which examined data over the period 1st October 2012 to 23rd May 2013, showed a positive correlation, albeit moderate, between system demand and MRS storage delivery flows; weak correlations between demand and flows at Dragon LNG and Isle of Grain LNG; and a negative correlation between demand and flows at South Hook.

In conclusion, we stated:

"While the correlation analysis does not consider peak day supply sources, as required by the Transportation Model, it does show that MRS facilities delivered gas into the NTS on the highest demand days experienced in the last seven months. Under more extreme conditions, it would be reasonable to expect that MRS facilities will deliver supply. In fact, based on our analysis combined with a wider appreciation of the operation of the international gas market it would be rational to propose that MRS facilities possess a greater propensity to supply volumes during periods of high demand than LNG and arguably, interconnectors."

In order to test the robustness of our assertions we have repeated the correlation tests using more up to date data spanning a longer period, with a focus on winter periods and shoulder months. The sample data covered the periods 1st October 2012 to 23rd May 2013 (the same period used in the previous analysis) and 1st October 2013 to 11th February 2014. Again, we have excluded flows from beach terminals.

We carried out a basic examination of this hypothesis by comparing supply flows from various entry points, excluding beach related flows, with daily demands experienced over the periods. This most recent supply and demand data should be the most relevant in terms of understanding how flow dynamics are responding to declining indigenous offshore reserves. The results have been presented in the form of supply duration curves i.e. highest demand days are situated to the left of the x-axis. During the period the highest demand day occurred on 16th January 2013, with a NTS demand of 393mcm or 4323GWh – which equates to 68% of the 1 in 20 undiversified peak demand.[12]

Figure 1 shows supplies from aggregated entry points, excluding beach, with total storage including Rough and MRS facilities operating over the period. The stacked representation shows the relationship between demand and supplies, with the highest demand day experienced recorded as demand day 1 on the x-axis.

Figure 1 – Stacked representation of supplies from non-beach sources (mcm) - 1st Oct 2012 and 23rd May 2013 and 1st Oct 2012 to 11th Feb 2014

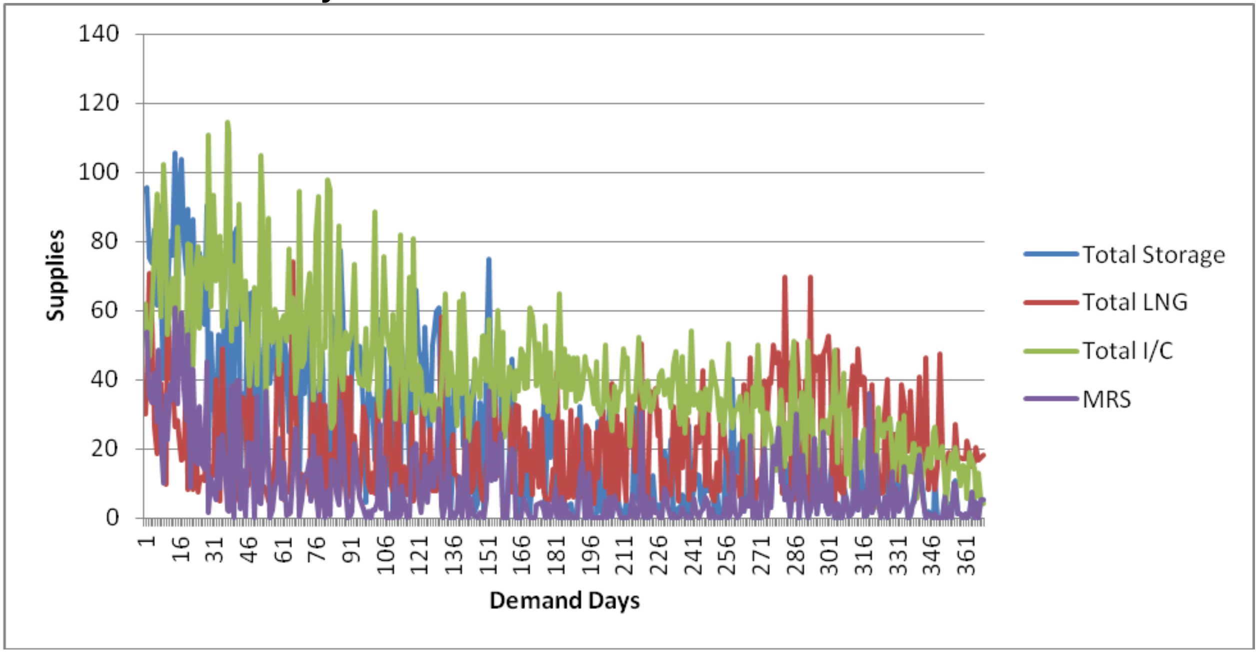
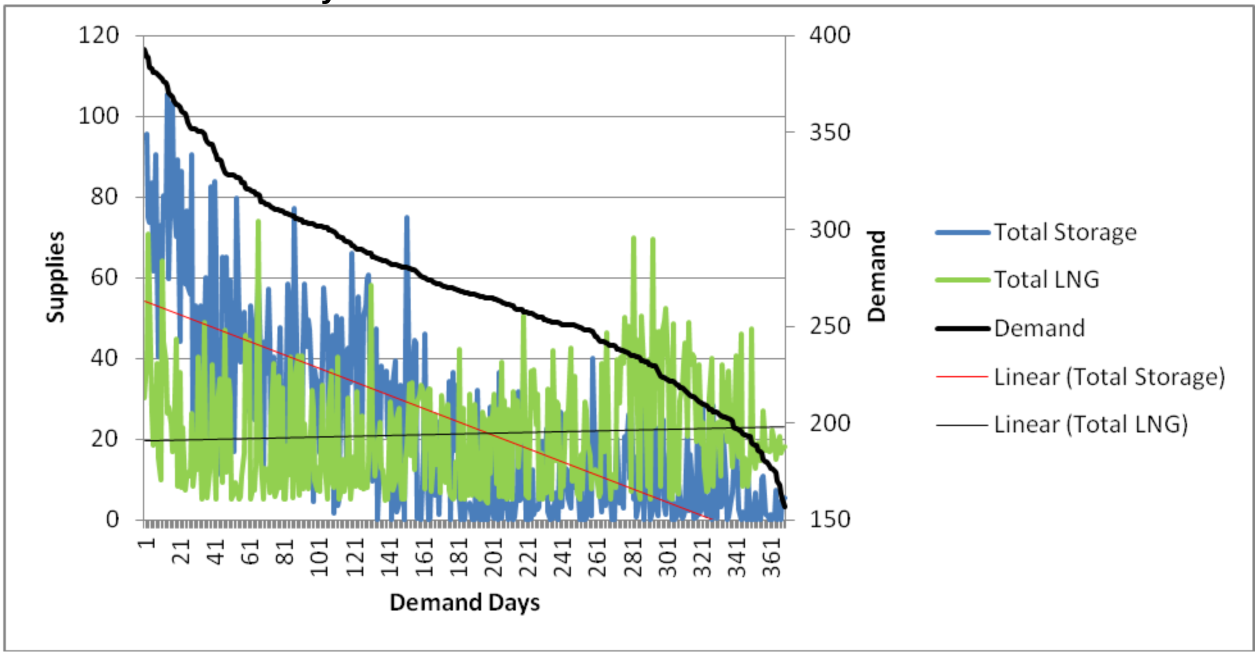


Figure 2 shows the relationships between total storage and LNG with demand, and includes linear trend lines.

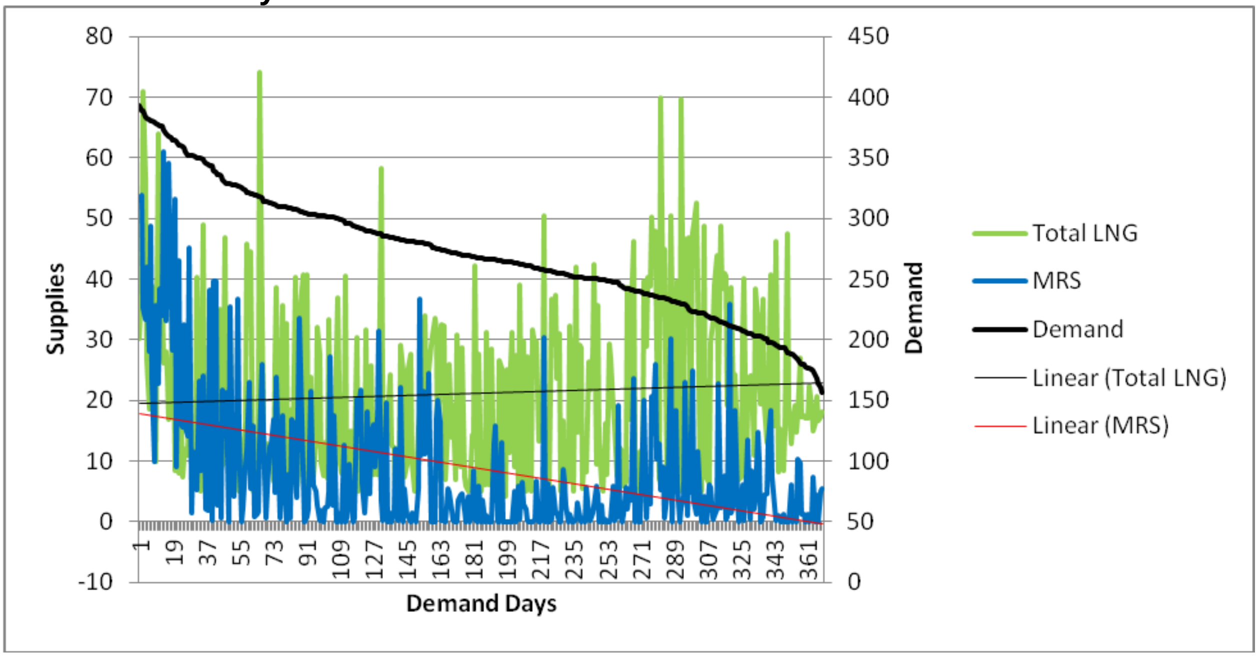
[12] Based on 2013/14 undiversified demand level of 572mcm/d

Figure 2 – Stacked representation of supplies from LNG and total storage (mcm) - 1st Oct 2012 and 23rd May 2013 and 1st Oct 2012 to 11th Feb 2014



Finally, figure 3 shows the relationships between MRS and LNG with demand and again includes linear trend lines.

Figure 3 – Stacked representation of supplies from LNG and MRS (mcm) - 1st Oct 2012 and 23rd May 2013 and 1st Oct 2012 to 11th Feb 2014



The figures above indicate a high degree of responsiveness in storage supply to changes in demand, with the opposite being the case in relation to LNG. In fact, the slope of the trend lines for LNG in figures 1 and 2 indicate a negative, or reverse correlation between LNG and demand over the period. More precise correlation analysis is provided below.

If we look at the "peak day" during the period, when demand was 393 mcm, supplies from LNG were 30 mcm and 53 mcm from MRS. Perhaps more telling is the comparative use of capacity – LNG supplies were at 20%[13] of aggregate peak available capacity, in contrast MRS supplies were at 53%.[14] This simplistic measure suggests that MRS has a greater propensity to supply gas on higher demand days.

Application of the Pearson's Correlation Coefficient indicates the extent of the correlation between demand levels and supply from the aggregated and Rough entry points, however, in the case of MRS the results should be viewed with caution as these facilities, in particular, respond not only to absolute levels of demand, but also relative levels across short periods of time.

Table 4 – Correlation analysis results

	Interconnectors	LNG	Total Storage	MRS	Rough
Sample	369	369	369	369	369
Correlation coeff. r	0.77	-0.02	0.75	0.51	0.76

The results of the correlation analysis, set out in table 4, are similar to those observed in our June 2013 GSOG report indicating a moderate positive correlation for MRS, which should be expected. For Rough and the interconnectors there is a far stronger correlation, with coefficients in excess of 0.7. This is unsurprising in relation to Rough, as it is a seasonal facility and will empty during the winter months; maximising flows at higher levels of demand (and price). The interconnector results suggest that flows are market responsive, although given supplies can be delivered to alternate markets; the volume of flow will be dependent upon price signals in those markets. As markets deregulate throughout Europe, flows may become more volatile. Finally, at the aggregated LNG entry points the correlation is negative, which reflects the flatter shape of the supply profile and the fact that flows from Isle of Grain were zero, or close to zero on 265 days of the period examined.[15]

In the case of South Hook the results reflect the "flatter" character of the supply over the period, although is worth noting on the highest demand day only 13.93mcm (153GWh) was delivered, whereas "peak" supply from South Hook occurred on the 282nd highest demand day (of 369 days); delivering a volume of 69.88mcm (768GWh). The correlation at Dragon is weak as it only supplied gas on 21 of the days sampled, supplying no volumes on the five highest demand days.

While the correlation analysis does not consider peak day supply sources, as required by the Transportation Model, it does show that MRS facilities delivered gas into the NTS on the highest demand days experienced in the period examined. Under more extreme conditions, it would be reasonable to expect that MRS facilities will deliver supply. In fact, based on our analysis combined with a wider appreciation of the operation of the international gas market it would be rational to propose that MRS facilities possess a greater propensity to supply volumes during periods of high demand than LNG and arguably, interconnectors.

[13] Maximum capacity of 150mcm/d based on National Grid obligated levels of capacity.
[14] Maximum deliverability of 100mcm/d based on National Grid Ten Year Statement 2013 approximations.
[15] Includes those days where supplies at Isle of Grain were less that 1mcm/day.

Given our findings are consistent with those from the analysis we carried out in 2013 we believe that it is appropriate to restructure the supply merit order, promoting MRS up the stack, either substituting all supply from LNG to MRS, or a proportion thereof.

3.3 Updated analysis approach

As discussed above, the analysis approach used for the 2007 original WWA report into storage benefits cannot be replicated using the Base Case assumptions within the TM, as supplied by National Grid, as there are no storage sites (other than Rough) assumed to be supplying gas which could be replaced in the model by alternative supplies. We have, therefore, decided to amend the Base Case supply stack as provided by National Grid, such that MRS storage sites are supplying gas into the system. This is consistent with our findings from the supply/demand correlation analysis and, indeed, with National Grid's own Winter Outlook assessment of supply sources on a cold winter's day.

Over the periods 1 October 2012 to 23 May 2013 and 1 October 2013 to 11 February 2014 the highest demand day was identified as being on 16 January 2013, with a NTS demand of 393mcm or 4323GWh. On that day, the two LNG importation terminals (Isle of Grain and Milford Haven) were supplying around 30 mcm of gas to the system and MRS around 53 mcm (Rough was also flowing around 41 mcm).

As part of its 2013/14 Winter Outlook Report, National Grid has quoted forecast figures for the 2013/14 winter expected on the 'Cold Day'[16] as per table 5.

Table 5 – National Grid winter 2013/14 Cold Day forecast

	2012/13 actual		2013/14 forecast	
mcm/d	Range	350+ Range	Range	Cold Day
UKCS	76 - 104	79 - 102	76 - 110	99
Norway	37 - 129	90 - 129	60 - 130	110
BBL	10 - 45	18 - 45	10 - 45	40
IUK	0 - 74	7 - 74	0 - 74	45
LNG Imports	8 - 74	8 - 74	8 - 100	50
Total	131 - 426	202 - 424	154 - 459	344
Storage	0 - 109	9 - 109	0 - 135	
Total incl. Storage	131 - 535	211 - 533	154 - 594	

This shows that LNG imports are expected to be around 50 mcm on a 344 mcm 'Cold Day'.[17] Our analysis of actual data outlined above showed that. on the highest demand day seen over the 2012/13 winter and 2013/14 winter period to date (393 mcm), LNG imports were only at 30 mcm. As a consequence we believe that around 50 mcm is more likely to be the supply from LNG imports on a 1 in 20 peak day. rather than on a 344 mcm demand day. This is the assumption we have used for the initial amended supply stack (Amended Base Case).

[16] National Grid has defined 'Cold Day' as follows "For 2013/14 we have used a different measure for the high supply day, and instead of showing supplies on a 400 mcm day we have shown supply on a 'Cold Day', one where the national average Composite Weather Variable (CWV) is around 0 degrees".
[17] Note the table as given by National Grid does not contain any forecast figures for Storage.

Within the TM, the LNG supply flows assumed in the original National Grid Base Case to match aggregate supply to the peak demand figure for 2016/17 of 6135.1 GWh are: 542.2 GWh for Isle of Grain; and 792.5 GWh for Milford Haven. These total 1334.7 GWh (or 121 mcm).

The Gone Green peak forecasts within the 2013 TYS for MRS for that year total 1692.2 GWh, so assuming the LNG sites supply only 551.5 GWh (50 mcm), we can apportion the remaining 783.2 GWh prorated across the MRS sites, which are assumed to be the existing facilities of Cheshire, Garton (Aldborough), Hatfield Moor, Hole House Farm, Hornsea and Barton Stacey (Humbly Grove).[18] This allows us to investigate the use of a more realistic supply stack within the TM.

We have used the deliverability figures for 2016/17 which are contained within the 2013 TYS as the basis for this proration. The resultant figures are shown in the table 6.

Table 6 – Amended Base Case supply stack

MRS site	2013 TYS Deliverability figure for 2016/17[19]	Resultant prorated MRS supplies and LNG supplies used in TM - Base Case 1
	GWh	GWh
Garton	440	241.0
Hatfield Moor	22	12.0
Hole House Farm	121	66.3
Hill Top Farm (Hole House Farm)	165	90.4
Holford (Cheshire)	242	132.5
Stublach (Cheshire)	165	90.4
Hornsea	198	108.4
Barton Stacey	77	42.2
Total MRS	**1430**	**783.2**
Isle of Grain		224.1
Milford Haven		327.5
Total LNG Importation		**551.5**
TOTAL		**1334.7**

Using this supply stack as our Amended Base Case we have repeated the analysis outlined in the 2007 report to derive a new Base Case Value. We have used the same approach as the 2007 report to investigate the potential savings in terms of investment costs which storage sites could provide. Note that the Rough site has been assumed to be flowing at 455.0 GWh on the 1 in 20 peak day and, therefore, we have assumed a total

[18] Within the Cheshire figure, we have included the existing facility at Holford and the new site which is proposed for startup during gas year 2013/14 at Stublach. Hole House Farm also includes the figure for Hill Top Farm which is also due for startup during gas year 2013/14. The two proposed facilities at Caythorpe and Fleetwood are also classified as MRS within the TM, but these have been excluded from the analysis here as the development of these sites is currently on hold.
[19] Figures within the TYS are quoted in mcm/d. We have again used a conversion factor of 11 to convert from mcm to GWh.

amount of storage replacement gas in the Amended Base Case of 1238.2 GWh/d (783.2 GWh/d from table 6 for MRS, plus 455.0 GWh/d for Rough).

WWA have also investigated moving all the gas within National Grid's Base Case away from the LNG importation terminals to MRS – a High Storage Case.

In this High Storage Case the full assumed values for LNG importation terminal of 1334.7 GWh (542.2 GWh for Isle of Grain and 792.5 GWh for Milford Haven) have been moved to MRS sites resulting in the following assumed flow assumptions for MRS sites (High Storage Case):

Table 7 – High Storage Case supply stack

MRS site	2013 TYS Deliverability figure for 2016/17[20]	Resultant prorated MRS supplies and LNG supplies used in TM - Base Case 2
	GWh	GWh
Garton	440	410.7
Hatfield Moor	22	20.5
Hole House Farm	121	112.9
Hill Top Farm (Hole House Farm)	165	154.0
Holford (Cheshire)	242	225.9
Stublach (Cheshire)	165	154.0
Hornsea	198	184.8
Barton Stacey	77	71.9
Total MRS	**1430**	**1334.7**
Isle of Grain		0
Milford Haven		0
Total LNG Importation		**0**
TOTAL		**1334.7**

Note that in this scenario, the supply figures for the Isle of Grain and Milford Haven LNG terminals within the TM have been set to zero.

Again the Rough site has been assumed to be flowing at 455.0 GWh on the 1 in 20 peak day and therefore we have assumed a total amount of storage replacement gas in the High Storage Case of 1789.7 GWh/d (1334.7 GWh/d from table 7 for MRS, plus 455.0 GWh/d for Rough).

As noted above, WWA believe that using a supply stack where MRS is flowing provides a much more realistic assumption of where actual supplies would be seen. However, it is not clear what the mix of LNG and MRS supplies on the 1 in 20 peak day will be. We have, therefore, used both Cases (Amended Base and High Storage) in our analysis to provide a range of the potential benefits in terms of avoided investment cost which storage sites provide. The High Storage Case can be thought of as providing an upper bound on

[20] Figures within the TYS are quoted in mcm/d. We have again used a conversion factor of 11 to convert from mcm to GWh.

that benefit; as it is starting from a position where more gas is assumed to be provided by the MRS sites and subsequently, a greater volume of replacement gas is allocated to the beach terminals/LNG importation facilities.

3.4 Alternative Supply Scenarios

WWA have repeated the analysis using the same alternative scenarios considered in the 2007 report, such that all the storage replacement gas is entered at only one of the six sites. This allows for a direct comparison between the results, but clearly these scenarios should be viewed as providing an upper bound to the benefit provided by storage to the system.

For consistency with the 2007 report, three more alternative scenarios have been modelled, which assume that the storage replacement gas is sourced partially through each, or a combination of, the six terminals:

1. storage replacement gas is sourced in equal volume at each of the terminals;
2. storage replacement gas is sourced in equal volume from the Bacton, Easington and Teesside terminals only;
3. storage replacement gas is sourced in equal volumes only via Bacton and Teesside.

In addition, WWA have considered a further alternative scenario, such that the maximum supply being assumed at the relevant entry points, if storage sites were unable to deliver gas onto the system on the 1 in 20 peak day, has been capped to ensure that it does not exceed the relevant obligated Entry Capacity level[21], as shown below.

- Bacton (1783.4 GWh/d)
- Easington (1407.15 GWh/d)
- Teesside (445.09 GWh/d)
- St Fergus (1607.7 GWh/d)
- Isle of Grain (699.68 GWh/d)
- Milford Haven (950 GWh/d).

This is arguably the most realistic case, in that it recognises existing import capacity limitations, and the two terminals affected by this capping are Bacton and Teesside. We have apportioned the rest of the storage replacement gas equally between the other four terminals. In applying the supply stacks comprised within the Amended Base and High Storage Cases, the amounts of additional gas assumed to be flowing on the 1 in 20 peak day at the six terminals considered under this scenario, are as set out in table 8 below.

[21] The obligated levels of Entry Capacity are as set out in Special Condition 5F of the GT licence which National Grid holds in respect of the NTS.

Table 8 – Storage replacement gas capped at obligated levels

Terminal	Amended Base Case additional gas GWh	High Storage Case additional gas GWh
Bacton	3.42	3.42
Easington	308.69	446.57
Teesside	0	0
St Fergus	308.69	446.57
Isle of Grain	308.69	446.57
Milford Haven	308.69	446.57
TOTAL	**1238.2**	**1789.7**

Additional to the analysis undertaken in 2007, WWA have also investigated the effects on both entry and exit prices of amending the supply stack, using both the Amended Base Case and High Storage Case supply stacks.

Finally, we have investigated the removal of the constraint within the TM that resultant prices must be 0.0001p/kWh/d, or greater. This means that capacity prices can be negative.

The following section sets out the results of all the analysis undertaken.

3.5 Results

<u>Scenario Values – compared with Amended Base Case (LNG and MRS flowing)</u>

Using the approach outlined above with our Amended Base Case we derive a Base Case Value of the NTS system of £3.554bn.[22] Again a sense check against the recent RIIO-T1 price control shows that this is of the same order of magnitude as the RAV of the NTS.[23]

Table 9 shows the savings in investment cost for the NTS through storage gas providing 1 in 20 peak day flows onto the NTS compared with replacing those aggregate flows from terminals in the percentages shown. The total column shows what additional capital investment would be needed, calculated from the TM as described above, by subtracting the Amended Base Case Value from the Scenario Value for each revised flow pattern.

[22] As the TM used in this analysis was issued for the March 2014 QSEC auction, this value can be assumed to be in 2013/14 prices.
[23] Table 2.5 of Ofgem's December 2012 Final Proposals Finance Annex shows the 2013/14 opening RAV value in 2009/2010 prices as £4.014bn.

Table 9 – Amended Base Case: Total CAPEX savings

All values shown in £million capital	**Bacton**	**Easington**	**Isle of Grain**	**Milford Haven**	**St Fergus**	**Teesside**	**Total**
Single Source Replacement of Storage Gas	100%						**£ 304m**
		100%					**£ 435m**
			100%				**£ 27m**
				100%			**£ 630m**
					100%		**£ 1,921m**
						100%	**£ 688m**
Replacement Gas Sourced in proportions:	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	**£ 404m**
	33.3%	33.3%	0.0%	0.0%	0.0%	33.3%	**£ 376m**
	50%	0.0%	0.0%	0.0%	0.0%	50%	**£ 390m**
Replacement Gas capped at obligated levels proportions:	0.3%	24.9%	24.9%	24.9%	24.9%	0.0%	**£ 458m**

Table 10 shows the same scenarios but with the capital cost saving converted to an annual cost saving through multiplication of the Annuitisation Factor, again as described above:

Table 10 – Amended Base Case – Annual CAPEX savings

All values shown in £million annual cost	**Bacton**	**Easington**	**Isle of Grain**	**Milford Haven**	**St Fergus**	**Teesside**	**Total**
Single Source Replacement of Storage Gas	100%						**£ 31m**
		100%					**£ 45m**
			100%				**£ 3m**
				100%			**£ 65m**
					100%		**£ 197m**
						100%	**£ 71m**
Replacement Gas Sourced in proportions:	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	**£ 41m**
	33.3%	33.3%	0.0%	0.0%	0.0%	33.3%	**£ 39m**
	50%	0.0%	0.0%	0.0%	0.0%	50%	**£ 40m**
Replacement Gas capped at obligated levels proportions:	0.3%	24.9%	24.9%	24.9%	24.9%	0.0%	**£ 47m**

Scenario Values – compared with High Storage Case (no LNG flowing, only MRS)

Using the approach outlined above with our High Storage Case we derive a Base Case Value of the NTS system of £3.8444bn. This is again of the same order of magnitude as the RAV of the NTS.

Table 11 shows the savings in investment cost for the NTS through the existence of MRS providing 1 in 20 peak day flows onto the NTS compared with replacing those aggregate flows in the percentages shown under the six terminal columns. The Total column shows what additional capital investment would be needed, calculated from the TM as described above by subtracting the Base Case Value using the High Storage Case from the Scenario Value for the revised flow pattern shown:

Table 11 – High Storage Case: Total CAPEX savings

All values shown in £million capital	**Bacton**	**Easington**	**Isle of Grain**	**Milford Haven**	**St Fergus**	**Teesside**	**Total**
Single Source Replacement of Storage Gas	100%						**£ 470m**
		100%					**£ 665m**
			100%				**£ 54m**
				100%			**£ 581m**
					100%		**£3,042m**
						100%	**£ 1,138m**
Replacement Gas Sourced in proportions:	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	**£ 359m**
	33.3%	33.3%	0.0%	0.0%	0.0%	33.3%	**£ 612m**
	50%	0.0%	0.0%	0.0%	0.0%	50%	**£ 680m**
Replacement Gas capped at obligated levels proportions:	0.2%	25.0%	25.0%	25.0%	25.0%	0.0%	**£ 359m**

Table 12 below shows the same scenarios, but with the capital cost saving converted to an annual cost saving through multiplying by the Annuitisation Factor, again as described above.

Table 12 – High Storage Case – Annual CAPEX savings

All values shown in £million annual cost	Bacton	Easington	Isle of Grain	Milford Haven	St Fergus	Teesside	**Total**
Single Source Replacement of Storage Gas	100%						**£ 48m**
		100%					**£ 68m**
			100%				**£ 6m**
				100%			**£ 60m**
					100%		**£ 312m**
						100%	**£ 117m**
Replacement Gas Sourced in proportions:	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	**£ 37m**
	33.3%	33.3%	0.0%	0.0%	0.0%	33.3%	**£ 63m**
	50%	0.0%	0.0%	0.0%	0.0%	50%	**£ 70m**
Replacement Gas capped at obligated levels proportions:	0.2%	25.0%	25.0%	25.0%	25.0%	0.0%	**£ 37m**

3.6 Pricing Sensitivities

As discussed above we have also investigated the effects on both entry and exit prices of amending the supply stack to include supply flows from storage sites rather than from LNG terminals. We have also removed the constraint that prices should be 0.0001p/kWh/d or greater. This would allow for the possibility of negative capacity charges, to reflect avoided transmission costs, as is already the case for electricity transmission charges applied to generation in 'capacity deficit' areas of the country. It should be understood that the resultant charges relate to the modelled impacts on a 1 in 20 demand day.

Table 13 and figure 4 show the effects of these changes (both singularly and when combined) on exit prices at storage offtake points.[24]

[24] To ensure consistency with the charging methodology and publication of charges performed by National Grid, LNG storage sites have been included, although we understand that these sites, with the exception of Avonmouth, are no longer operational.

Table 13 – Effects on NTS Exit Capacity charges for storage sites

Storage Offtake Point	Exit Price (p/kWh/day)					
	Original TM run	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
Avonmouth Max Refill	0.0223	0.0243	0.0249	0.0274	0.0266	0.0301
Barton Stacey Max Refill (Humbly Grove)	0.0233	0.0252	0.0223	0.0248	0.0247	0.0282
Caythorpe	0.0001	-0.0001	0.0001	-0.0039	0.0001	-0.0046
Cheshire (Holford)	0.0219	0.0238	0.0174	0.0199	0.0089	0.0124
Dynevor Max Refill	0.0037	0.0057	0.0224	0.0249	0.0281	0.0317
Rough Max Refill	0.0001	-0.0052	0.0001	-0.0056	0.0001	-0.0030
Garton Max Refill (Aldbrough)	0.0001	-0.0033	0.0001	-0.0050	0.0001	-0.0024
Glenmavis Max Refill	0.0001	-0.0049	0.0001	-0.0062	0.0001	-0.0125
Hatfield Moor Max Refill	0.0010	0.0029	0.0001	0.0021	0.0008	0.0043
Hill Top Farm (Hole House Farm)	0.0225	0.0244	0.0183	0.0208	0.0096	0.0131
Hole House Max Refill	0.0225	0.0244	0.0183	0.0208	0.0096	0.0131
Hornsea Max Refill	0.0001	-0.0015	0.0001	-0.0054	0.0001	-0.0038
Partington Max Refill	0.0212	0.0232	0.0194	0.0219	0.0109	0.0144
Stublach (Cheshire)	0.0219	0.0238	0.0174	0.0199	0.0089	0.0124
Saltfleetby Storage (Theddlethorpe)	0.0001	-0.0015	0.0001	-0.0020	0.0001	0.0006
Average of the Storage Offtake Point Exit price range	**0.0107**	**0.0107**	**0.0107**	**0.0103**	**0.0086**	**0.0089**
Minimum of Storage Offtake Exit price range	0.0001	-0.0052	0.0001	-0.0062	0.0001	-0.0125
Maximum of Storage Offtake Exit price range	0.0233	0.0252	0.0249	0.0274	0.0281	0.0317
Standard deviation for the Storage Offtake Point Exit price range	0.0112	0.0133	0.0105	0.0138	0.0102	0.0136

Storage Offtake Point	Percentage change from Original TM run				
	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
Avonmouth Max Refill	9%	12%	23%	19%	35%
Barton Stacey Max Refill (Humbly Grove)	8%	-4%	6%	6%	21%
Caythorpe	-200%	0%	-4000%	0%	-4700%
Cheshire (Holford)	9%	-21%	-9%	-59%	-43%
Dynevor Max Refill	54%	505%	573%	659%	757%
Rough Max Refill	-5300%	0%	-5700%	0%	-3100%
Garton Max Refill	-3400%	0%	-5100%	0%	-2500%
Glenmavis Max Refill	-5000%	0%	-6300%	0%	-12600%
Hatfield Moor Max Refill	190%	-90%	110%	-20%	330%
Hill Top Farm (Hole House	8%	-19%	-8%	-57%	-42%
Hole House Max Refill	8%	-19%	-8%	-57%	-42%
Hornsea Max Refill	-1600%	0%	-5500%	0%	-3900%
Partington Max Refill	9%	-8%	3%	-49%	-32%
Stublach (Cheshire)	9%	-21%	-9%	-59%	-43%
Saltfleetby Storage (Theddlethorpe)	-1600%	0%	-2100%	0%	500%
Average of the Storage Offtake Point Exit price range	**0%**	**0%**	**-4%**	**-20%**	**-17%**
Minimum of Storage Offtake Exit price range	-5300%	0%	-6300%	0%	-12600%
Maximum of Storage Offtake Exit price range	8%	7%	18%	21%	36%

Figure 4 – Variations in NTS Exit Capacity charges for Storage

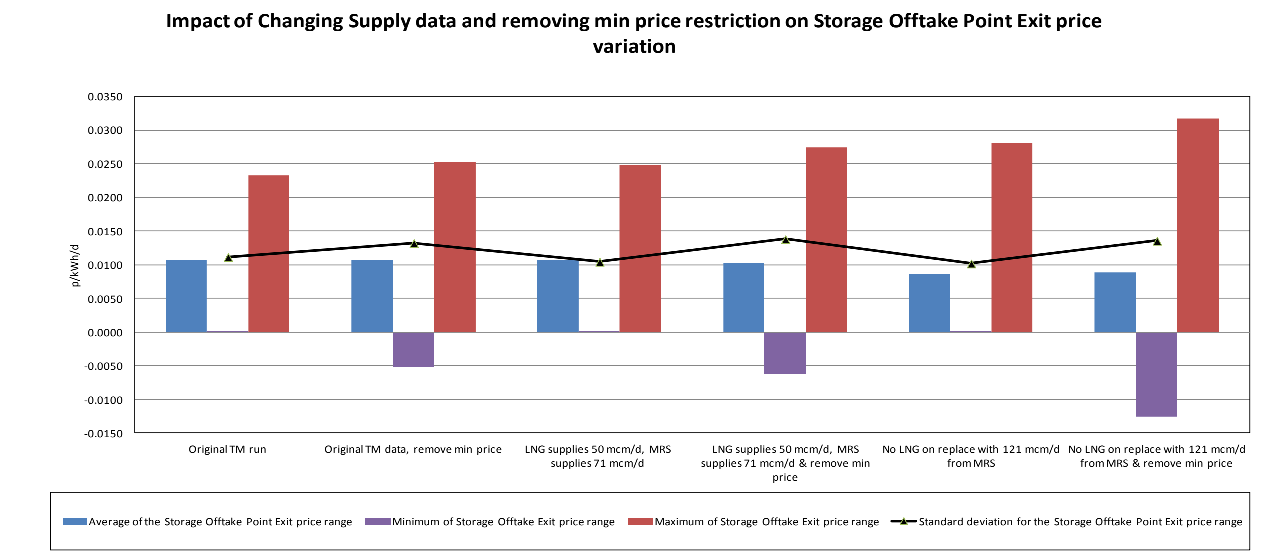


Table 14 and figure 5 show the effects of these changes (both singularly and when combined) on exit prices at DN exit zones:

Table 14 – Effects on NTS Exit Capacity charges for DNs

DN Exit Zone	Exit Price (p/kWh/day)					
	Original TM run	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
EA1	0.0038	0.0053	0.0029	0.0049	0.0050	0.0083
EA2	0.0038	0.0057	0.0028	0.0053	0.0052	0.0087
EA3	0.0001	0.0006	0.0001	0.0001	0.0001	0.0035
EA4	0.0102	0.0121	0.0092	0.0117	0.0116	0.0151
EM1	0.0001	-0.0021	0.0001	-0.0026	0.0001	0.0000
EM2	0.0022	0.0041	0.0011	0.0037	0.0026	0.0062
EM3	0.0147	0.0166	0.0137	0.0162	0.0146	0.0181
EM4	0.0093	0.0113	0.0083	0.0108	0.0100	0.0135
NE1	0.0037	0.0056	0.0019	0.0043	0.0001	-0.0009
NE2	0.0004	-0.0009	0.0001	-0.0029	0.0001	-0.0022
NE3	0.0001	-0.0033	0.0001	-0.0037	0.0001	-0.0011
NO1	0.0001	0.0003	0.0001	-0.0010	0.0001	-0.0073
NO2	0.0043	0.0063	0.0025	0.0050	0.0001	-0.0013
NT1	0.0209	0.0228	0.0199	0.0224	0.0223	0.0258
NT2	0.0112	0.0131	0.0102	0.0127	0.0126	0.0161
NT3	0.0106	0.0125	0.0096	0.0121	0.0120	0.0155
NW1	0.0168	0.0188	0.015	0.0175	0.0077	0.0112
NW2	0.0223	0.0243	0.0199	0.0224	0.0114	0.0149
SC1	0.0001	-0.0211	0.0001	-0.0224	0.0001	-0.0287
SC2	0.0001	-0.0043	0.0001	-0.0056	0.0001	-0.0119
SC4	0.0001	-0.0063	0.0001	-0.0076	0.0001	-0.0139
SE1	0.0121	0.0141	0.0132	0.0157	0.0157	0.0192
SE2	0.0209	0.0228	0.0199	0.0224	0.0223	0.0258
SO1	0.0146	0.0166	0.0136	0.0161	0.0161	0.0196
SO2	0.0239	0.0259	0.0234	0.0259	0.0258	0.0293
SW1	0.0125	0.0145	0.0177	0.0202	0.0193	0.0228
SW2	0.0216	0.0236	0.0243	0.0268	0.0259	0.0294
SW3	0.0346	0.0366	0.0372	0.0397	0.0388	0.0424
WA1	0.0245	0.0264	0.0225	0.025	0.014	0.0176
WA2	0.0041	0.0061	0.0229	0.0254	0.0278	0.0314
WM1	0.0194	0.0214	0.0182	0.0207	0.0126	0.0162
WM2	0.0156	0.0175	0.0146	0.0171	0.0162	0.0197
WM3	0.013	0.015	0.0137	0.0162	0.0153	0.0188
Average of the DN Exit Zone Exit price range	**0.0107**	**0.0110**	**0.0109**	**0.0113**	**0.0111**	**0.0116**
Minimum of DN Exit Zone Exit price range	0.0001	-0.0211	0.0001	-0.0224	0.0001	-0.0287
Maximum of DN Exit Zone Exit price range	0.0346	0.0366	0.0372	0.0397	0.0388	0.0424
Standard deviation for the DN Exit Zone Point Exit price range	0.0093	0.0119	0.0097	0.0128	0.0101	0.0148

DN Exit Zone	Percentage change from Original TM run				
	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
EA1	39%	-24%	29%	32%	118%
EA2	50%	-26%	39%	37%	129%
EA3	500%	0%	0%	0%	3400%
EA4	19%	-10%	15%	14%	48%
EM1	-2200%	0%	-2700%	0%	-100%
EM2	86%	-50%	68%	18%	182%
EM3	13%	-7%	10%	-1%	23%
EM4	22%	-11%	16%	8%	45%
NE1	51%	-49%	16%	-97%	-124%
NE2	-325%	-75%	-825%	-75%	-650%
NE3	-3400%	0%	-3800%	0%	-1200%
NO1	200%	0%	-1100%	0%	-7400%
NO2	47%	-42%	16%	-98%	-130%
NT1	9%	-5%	7%	7%	23%
NT2	17%	-9%	13%	13%	44%
NT3	18%	-9%	14%	13%	46%
NW1	12%	-11%	4%	-54%	-33%
NW2	9%	-11%	0%	-49%	-33%
SC1	-21200%	0%	-22500%	0%	-28800%
SC2	-4400%	0%	-5700%	0%	-12000%
SC4	-6400%	0%	-7700%	0%	-14000%
SE1	17%	9%	30%	30%	59%
SE2	9%	-5%	7%	7%	23%
SO1	14%	-7%	10%	10%	34%
SO2	8%	-2%	8%	8%	23%
SW1	16%	42%	62%	54%	82%
SW2	9%	13%	24%	20%	36%
SW3	6%	8%	15%	12%	23%
WA1	8%	-8%	2%	-43%	-28%
WA2	49%	459%	520%	578%	666%
WM1	10%	-6%	7%	-35%	-16%
WM2	12%	-6%	10%	4%	26%
WM3	15%	5%	25%	18%	45%
Average of the DN Exit Zone Exit price range	**3%**	**2%**	**6%**	**4%**	**9%**
Minimum of DN Exit Zone Exit price range	-21200%	0%	-22500%	0%	-28800%
Maximum of DN Exit Zone Exit price range	6%	8%	15%	12%	23%

Figure 5 – Variations in NTS Exit Capacity charges for DNs

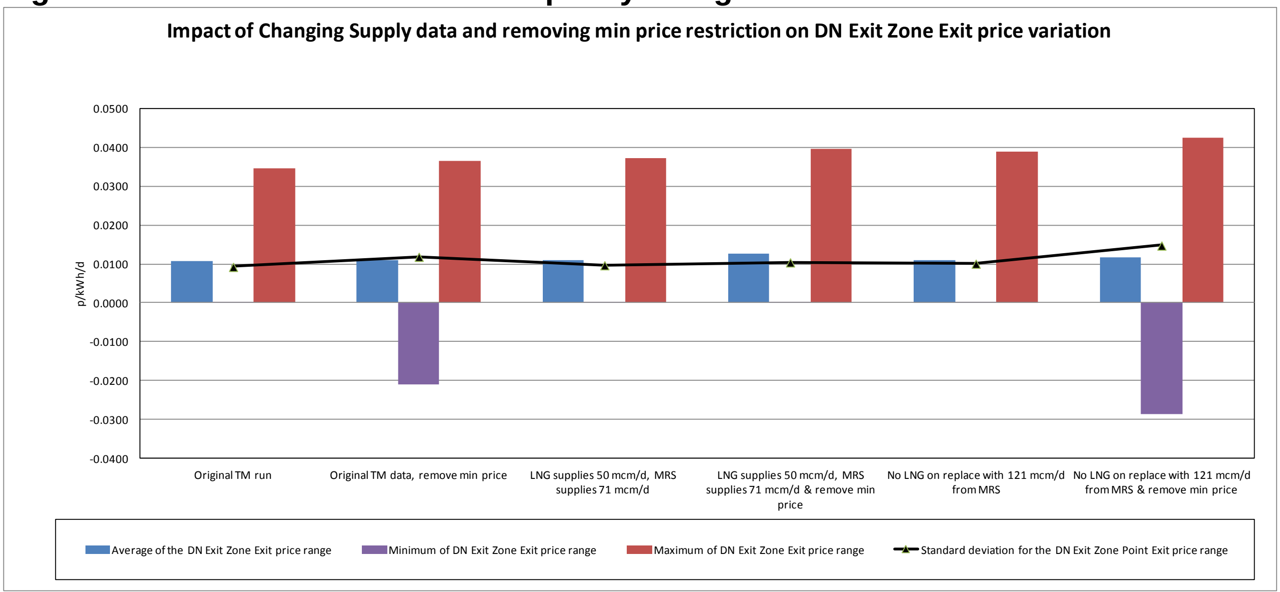


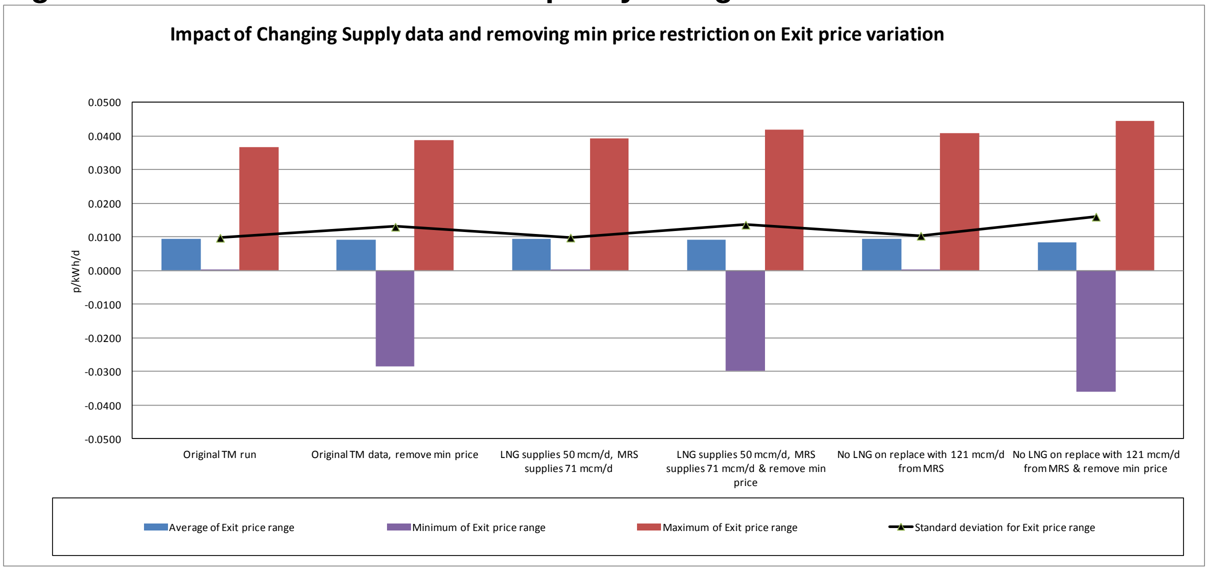
Table 15 figure 6 and graph shows the effects of these changes (both singularly and when combined) on all exit prices:

Table 15 – Effects on NTS Exit Capacity charges across all Exit Points

All Exit Points	Exit Price (p/kWh/day)					
	Original TM run	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
Average of Exit price range	**0.0094**	**0.0091**	**0.0095**	**0.0092**	**0.0093**	**0.0085**
Minimum of Exit price range	0.0001	-0.0286	0.0001	-0.0298	0.0001	-0.0361
Maximum of Exit price range	0.0367	0.0387	0.0393	0.0418	0.0409	0.0445
Standard deviation for Exit price range	0.0098	0.0131	0.0099	0.0137	0.0104	0.0161

All Exit Points	Percentage change from Original TM run				
	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
Average of Exit price range	**-4%**	**1%**	**-3%**	**-1%**	**-10%**
Minimum of Exit price range	-28700%	0%	-29900%	0%	-36200%
Maximum of Exit price range	5%	7%	14%	11%	21%

Figure 6 – Variations in NTS Exit Capacity charges across all Exit Points



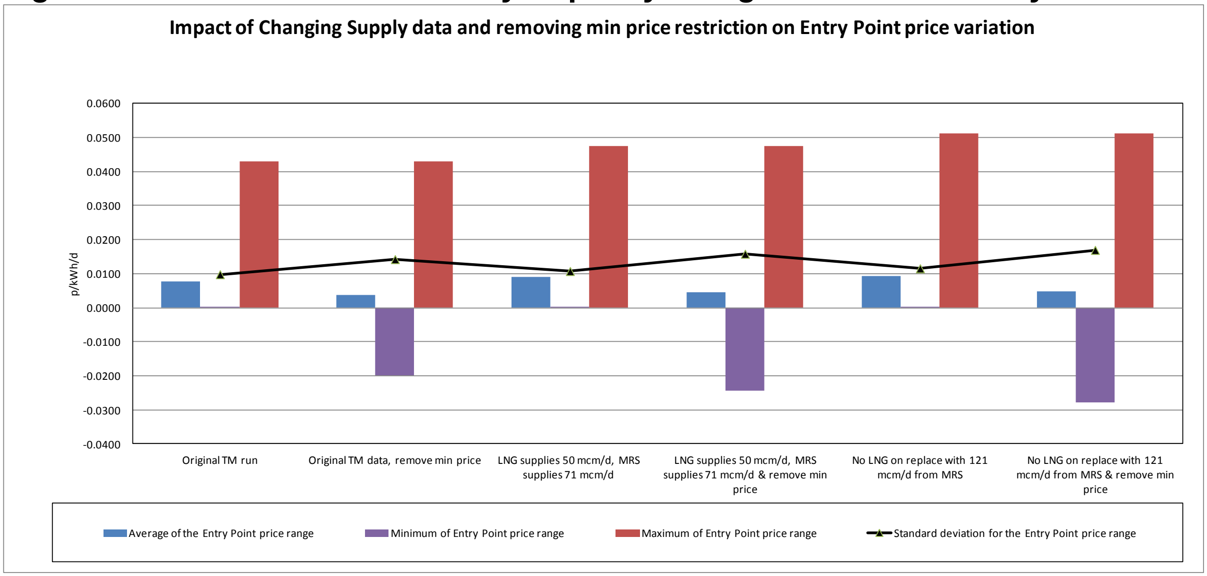
The following table and graph shows the effects of these changes (both singularly and when combined) on entry prices:

Table 16 – Effects on NTS Entry Capacity charges for Storage & Entry Terminals

Entry Points	Entry Price (p/kWh/day)					
	Original TM run	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
Avonmouth	0.0001	-0.0057	0.0001	-0.0150	0.0001	-0.0160
Bacton	0.0096	0.0096	0.0104	0.0104	0.0065	0.0065
Barrow	0.0001	0.0001	0.0085	0.0085	0.0072	0.0072
Barton Stacey	0.0001	-0.0113	0.0001	-0.0165	0.0001	-0.0182
Burton Point	0.0001	-0.0200	0.0001	-0.0164	0.0001	-0.0081
Canonbie	0.0034	0.0034	0.0050	0.0050	0.0107	0.0107
Caythorpe	0.0125	0.0125	0.0142	0.0142	0.0131	0.0131
Cheshire	0.0001	-0.0046	0.0001	-0.0014	0.0001	-0.0007
Dynevor Arms	0.0071	0.0071	0.0001	-0.0102	0.0001	-0.0226
Easington & Rough	0.0130	0.0130	0.0132	0.0132	0.0116	0.0116
Fleetwood	0.0020	0.0020	0.0070	0.0070	0.0083	0.0083
Garton	0.0129	0.0129	0.0129	0.0129	0.0095	0.0095
Glenmavis	0.0128	0.0128	0.0159	0.0159	0.0205	0.0205
Hatfield Moor	0.0050	0.0050	0.0056	0.0056	0.0029	0.0029
Hole House Farm	0.0001	-0.0133	0.0001	-0.0100	0.0001	-0.0057
Hornsea	0.0118	0.0118	0.0136	0.0136	0.0123	0.0123
Isle of Grain	0.0013	0.0013	0.0046	0.0046	0.0056	0.0056
Milford Haven	0.0205	0.0205	0.0242	0.0242	0.0241	0.0241
Partington	0.0001	-0.0141	0.0001	-0.0060	0.0001	-0.0013
St Fergus	0.0430	0.0430	0.0475	0.0475	0.0513	0.0513
Teesside	0.0090	0.0090	0.0105	0.0105	0.0162	0.0162
Theddlethorpe	0.0123	0.0123	0.0131	0.0131	0.0120	0.0120
Wytch Farm	0.0001	-0.0193	0.0001	-0.0243	0.0001	-0.0278
Average of the Entry Point price range	**0.0077**	**0.0038**	**0.0090**	**0.0046**	**0.0092**	**0.0048**
Minimum of Entry Point price range	0.0001	-0.0200	0.0001	-0.0243	0.0001	-0.0278
Maximum of Entry Point price range	0.0430	0.0430	0.0475	0.0475	0.0513	0.0513
Standard deviation for the Entry Point price range	0.0098	0.0143	0.0108	0.0158	0.0116	0.0170

Entry Points	Percentage change from Original TM run				
	Original TM data, remove min price	Amended Base Case	Amended Base Case remove min price	High Storage Case	High Storage Case remove min price
Avonmouth	-5753%	0%	-15140%	0%	-16129%
Bacton	0%	8%	8%	-32%	-33%
Barrow	48%	8400%	8394%	7100%	7068%
Barton Stacey	-11415%	0%	-16559%	0%	-18266%
Burton Point	-20095%	0%	-16549%	0%	-8218%
Canonbie	0%	47%	46%	215%	214%
Caythorpe	0%	14%	14%	5%	5%
Cheshire	-4707%	0%	-1480%	0%	-819%
Dynevor Arms	1%	-99%	-244%	-99%	-418%
Easington & Rough	0%	2%	1%	-11%	-11%
Fleetwood	0%	250%	249%	315%	315%
Garton	0%	0%	0%	-26%	-26%
Glenmavis	0%	24%	24%	60%	60%
Hatfield Moor	1%	12%	13%	-42%	-41%
Hole House Farm	-13406%	0%	-10110%	0%	-5848%
Hornsea	0%	15%	15%	4%	4%
Isle of Grain	2%	254%	253%	331%	331%
Milford Haven	0%	18%	18%	18%	17%
Partington	-14213%	0%	-6116%	0%	-1384%
St Fergus	0%	10%	10%	19%	19%
Teesside	0%	17%	17%	80%	80%
Theddlethorpe	0%	7%	6%	-2%	-3%
Wytch Farm	-19358%	0%	-24378%	0%	-27904%
Average of the Entry Point price range	**-50%**	**17%**	**-40%**	**20%**	**-37%**
Minimum of Entry Point price range	-20095%	0%	-24378%	0%	-27904%
Maximum of Entry Point price range	0%	10%	10%	19%	19%

Figure 7 – Variations in NTS Entry Capacity charges for MRS & Entry Terminals



3.7 Observations

On the evidence of recent flow behaviour it would appear entirely reasonable to recommend that the supply merit order employed by National Grid within the TM does not reflect an accurate representation of the actual supply stack.

Following implementation of NTS GCM 016, changes were made to the structure of the merit order; the methodology to "scale back" supplies from each supply type; and the data used to inform the supply/demand assumptions. In terms of the structure of the merit order, LNG supplies were relegated down the order, we assume to reflect an expectation at the time that LNG was less likely to supply gas on a peak day. Equally, on the basis that MRS featured below LNG in the merit order, it must have been assumed that on a peak day, LNG would be more likely to supply gas to the NTS than MRS. Based on recent evidence this assumption does not appear to hold true.

In particular, LNG supplies have been volatile exhibiting an overall negative correlation with system demand. On the highest demand day experienced over the period examined, LNG supplies were around 50% of the volume supplied from MRS using only 20% of the obligated levels of capacity. We perceive little prospect of any significant change to this outcome due to the global gas market directing LNG to other geographical markets and the fact the MRS, being highly price responsive, has a very high probability of delivering gas on days of high domestic demand.[25]

On this basis we believe that the supply merit order should be modified and MRS should be promoted up the stack, either replacing LNG supplies, or a proportion thereof.

If it is accepted that our core merit order assumptions are valid, then the system benefit analysis indicates that under both supply scenarios there are significant benefits to the

[25] Also note that MRS is "fast cycle" meaning it can switch between injection and delivery in short timescales. Given peak demand would reasonably be expected to occur on a weekday, experience shows that MRS tends to fill at weekends and deliver on weekdays, making the probability of delivery on a peak demand day, high.

transmission system provided by storage. The benefits have been calculated on the basis of avoided CAPEX with greatest concentration around £350-£600m in terms of total savings (£40-£65m pa).[26] The results are reasonably consistent with those presented in the 2007 report, although it should be noted that unsurprisingly the High Storage Case produces, generally, increased levels of savings. The exceptions to this trend concern the three scenarios; 100% replacement gas sourced from Milford Haven; replacement gas sourced in proportions; and replacement gas capped at obligated levels proportions. In these scenarios the total savings decrease in the High Storage Case when compared with the Amended Base Case. This apparent anomaly can be explained perhaps by the absolute increase in replacement gas volumes at Milford Haven, but more broadly, by the sensitivity of the model to changes in flow assumptions.

Again, on the basis of our findings we believe that in line with our previous findings it is correct to say that;

"*Gas storage sites* ***do*** *provide a benefit to the transmission system because on peak days they deliver to the system close to consumer demand, thereby reducing the need for pipe and compression capacity between alternative sources of gas and the demand."*

It is important to note that the changes to the merit order assumptions do not confer upon the storage sites a realisation of the benefits they provide to the NTS. The benefits identified are those which can be ascribed to storage after the changes to the merit order have been incorporated within the TM.

Turning to the impact on prices of modifying the supply merit order, it can be clearly seen that there significant changes to price levels for the majority of storage sites under all of the scenarios examined.

In relation to exit charges the range is -5700% (Rough) to +21% (Barton Stacey), if the impacts on LNG storage are ignored. For DN connections to the NTS the range is even greater, recording -28,800% (SC1) to +3,400% (EA3). At entry, the charges range from @ –18000% (Barton Stacey) to @+8000% (Barrow), again with the exclusion of LNG storage.

As described in the Section 2 of this report the virtual nodal methodology adopted by GB in 2007 means that entry and exit charges are treated independently, reflecting costs of transporting gas to and from the virtual node. Intuitively, the outturn prices are rational as on a peak day, storage will be delivering gas into the network (entry gas) and not injecting (exit gas).

The first main observation to make is that the TM is structured in such a way that it is exceedingly sensitive to changes in assumptions. This is a well understood feature of the TM, but the results produced from this analysis highlight that any modifications to the supply and demand flow assumptions produce extraordinary swings in prices.

Secondly, and perhaps less surprising, is that removing the price floor leads to greater swings at each individual system point and higher standards of deviation.

[26] Around 7-10% of TO Allowed Revenue

Thirdly, when considering those scenarios which include a floor price, the impacts are generally more favourable in relation to exit charges than entry charges for MRS sites.

Finally, the analysis does not consider the impacts on overall levels of revenue and by extension does not consider the potential impacts on the TO commodity charge.

4. Examples of alternative charging methodologies

In this section WWA consider how transmission charges are levied in the GB electricity market as well as how DNs charge shippers for delivering gas into their networks from embedded production facilities. Finally, we consider the approaches adopted by other EU countries in relation to charges applied at storage points on their networks.

4.1 Overview of GB electricity transmission use of system charges (TNUoS)

Transmission charges are set to recover allowed revenue for National Grid Electricity Transmission's (NGET's) and other relevant GB transmission company transmission owner (TO) costs. Under or over-recovery of allowed revenues are reflected in adjustments to the following year's charges (the "K factor"). In 2012/13 the TO costs were recovered through some £1,600m of transmission network use of system (TNUoS) charges and £150m of connection charges.

TNUoS charges are levied on network users on a capacity basis and cover the cost of maintaining and building network infrastructure assets. It includes the assets of the Scottish transmission owners Scottish Power Transmission Ltd (SPTL) and Scottish Hydro Electric Ltd (SHETL) as well as those of offshore transmission owners (OFTOs). Connection charges recover the specific cost of connection assets provided for particular users.

For the purpose of relevant comparison with gas transmission charges we examine only the TNUoS charges and how these are determined by NGET. Unlike gas there are no commodity charges for use of the electricity transmission system.

The GB TOs seek to develop the system in accordance with the National Electricity Transmission System Security and Quality Supply Standards (NETS SQSS). The primary focus of these standards is to ensure the network is capable of transporting sufficient power to consumers during peak demand periods. Nevertheless, in recent years some generators have been permitted to connect to the system prior to the system being fully reinforced to the required NETS SQSS. In such circumstances the consequential additional balancing costs of managing the system are socialised across all users of the system under a policy known as "connect and manage".

NGET's clause C5 transmission licence obligation sets out various relevant Connection and Use of System Code (CUSC) objectives which also apply to charging arrangements, including "promoting competition in generation and supply" and a system charging methodology that "results in changes which reflect, as far as is reasonably practicable, the costs incurred by transmission companies" (i.e. the relevant TOs). There is also a broad non-discrimination obligation set out in clause C7.

Given that most TO investment is driven by requirements to meet peak demand, the TNUoS charging methodology has naturally considered that charges should be based on use of the electricity transmission during the peak (as with gas). It also assumes that it is 'cost-reflective' to levy charges that may influence the siting decisions of generators[27] (whether new plant or plant closure decisions). However, it is also fair to say that how TNUoS charges are levied also influences how users choose to utilise the network during peak periods (triad avoidance).

In their annual TNUoS Statement NGET state;
"The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy."

Calculation of TNUoS charges is managed in two stages: firstly, the transport model which seeks to derive long run marginal costs for changes to incremental power flows on the system and then the tariff model, which adjusts these to recover the 'correct' allowed revenue and to allocate charges amongst different classes of users.

The transport model can be viewed as a genuinely objective means of producing 'cost reflective' raw marginal pricing signals based on likely usage of the system, whereas the tariff model is the adjustment process that is necessary to deliver the allowed revenue recovery and address the political realities associated with sharing costs between particular classes of users. A detailed description of the two models is provided in Appendix 1.

Key observations

- Negative electricity transmission system charges are permitted and apply to generation and demand based on the locational benefits that such users provide to the system;
- The concept of Triad demand is used to encourage demand reduction during peak periods. If demand is reduced by an offtaker during the Triad periods this will result in reduced TNUoS charges. If one views gas deliveries into the system as 'negative demand' it is surely conceptually similar to triad avoidance in electricity? Thus, parties delivering gas during peak periods at locations where raw LRMCs are negative might be rewarded at the level of deliveries made during those peak periods;
- Electricity transmission charges are levied on a capacity basis; there are no commodity based charges, however the residual flat non-locational element typically represents a huge 80% of the tariff;
- The allocation of revenues, and therefore charges, is based on a 73:27 split with the majority of costs incurred by suppliers. In gas the split is 50:50.

[27] Locational charge differentials also apply to demand, although it is generally accepted that in electricity siting decisions for demand, save for perhaps those of major energy users (e.g. plant closure decisions), are unlikely to be influenced by these pricing signals. The siting of embedded generation, which reduces the level of demand within a demand zone is likely to be relevant.

- Project TransmiT implementation under CMP213 is likely to result in a move away from allocating charges solely on the basis of peak usage. It also provides for different charges for different classes of user depending on the different usage that such users make of the transmission system;
- Any design of charges will need to take account of the relevant differences between different classes of users. In gas, therefore, we suggest that any different treatment of gas storage from other providers of peak gas flexibility would have to be objectively justified.

4.2 DN entry arrangements

Since the implementation of UNC modification 0391 in April 2013 gas supplied directly into the DNs (known as Distributed Gas) has been subject to tailored transportation charging arrangements. The modification was proposed and ultimately approved on the basis that the LDZ charging methodology needed to be changed "*to more accurately reflect the costs associated with the entry of distributed gas directly into the distribution networks."*

The modification is targeted at DN entry points, which includes storage facilities at such times as they are delivering gas into the networks – during injection periods, flows into storage would be subject to DN charges normally applied to gas offtakes.

In simple terms the modification introduced the concept of a LDZ System Entry Commodity Charge calculated as follows:

Unit Rate for Opex Costs + Unit Rate for LDZ System Credit + Unit Rate for ECN

Where:
- The Unit Rate for Opex Costs would be zero or positive depending on the forecast Opex costs incurred to accommodate the individual distributed gas entry point.
- The Unit Rate for LDZ System Credit would be zero or negative depending on the pressure tier to which the entry point is connected.
- The Unit Rate for ECN would be zero or negative depending on the level of the average DN ECN charge and the load factor of the entry point.

The resulting LDZ System Entry Commodity could be positive or negative (i.e. providing a credit to for each kWh of gas delivered through the entry point).

In its decision the Authority stated:

"This modification introduces a LDZ System Entry Commodity Charge which reflects the cost impact of distributed gas entry in three different ways:
• unit rate for Opex costs – the level of entry-related equipment operating costs for each distributed gas entry point will be reflected in the unit entry commodity charge relating to opex costs;
• unit rate for LDZ system credit – a utilisation credit will reflect lower LDZ utilisation for gas entering from distributed gas entry points; and
• unit rate for ECN credit – distributed generators will potentially receive a credit to reflect the fact that they provide an alternative to NTS Exit capacity to ensure the flow of gas into the DN network at peak times. The ECN charges will come into force from October 2012."

As far as NTS charges for storage flows are concerned there are a number of discussion points which can be gleaned from the various components of the LDZ system entry commodity charge. Firstly, the approach to Opex costs is akin to that already applied to storage, as under the current methodology the SO commodity charge is not applied to gas delivered to or supplied from the storage facility.[28] Secondly, the LDZ credit is perhaps unique to the DN charging methodology which bases charges on the various pressure tiers comprised within the LDZ's. Unlike the LDZs the NTS is not made up of a series of different-sized pipes delivering gas at various pressures to the connected customers. On this basis, it would be difficult to argue that storage facilities should be subject to a NTS-equivalent LDZ system credit.

The ECN credit, however, does provide a reasonable precedent for supporting an argument that storage facilities provide a benefit to the NTS and should be "rewarded" accordingly. In summary, the case can be made as follows:

The ECN credit reflects the fact that the delivery of embedded gas flows reduces the need for a DN to purchase NTS Exit Capacity; necessary to support the supply of gas from the NTS. It is reasonable to state that the purchase of NTS Exit Capacity is a DN investment (the cost of which is passed through to DN shippers) which can be offset, or "saved", by the flows delivered by the DN entry points. The investment savings enjoyed by the DN are analogous to the NTS CAPEX savings identified in the analysis contained in Section 3 of this report.

Finally, and perhaps crucially, the LDZ system entry commodity charge permits the application of a negative charge, or credit which in short recognises the network benefits delivered by the distributed entry facilities.

4.3 European approach to transmission charges for storage

The most recent publically available study into the various approaches adopted by member states is the ACER initial impact assessment published in September 2012 in support of the consultation on the Framework Guidelines on harmonised transmission tariff structures for European natural gas networks. Where more recent information is available we have updated the analysis and presented it in table 17. .

Table 17 – Overview of transportation tariffs at EU storage facilities

Member State	TSO	Specific Transportation Tariff For Storage	Tariff characteristics summarised
UK	National Grid	yes	Potential to use product with Zero reserve price, commodity charge only applied for gas used by the storage facility
DE	Open Grid Europe	yes	Entry & Exit tariffs reduced 50%
DE	Thyssengas	yes	>33%% reduction exit, small reduction entry

[28] With the exception of own-use gas.

IT	SNAM Rete Gas	yes	More than 60% reduction entry and exit
FR	GRTGaz	yes	More than 80% reduction on entry and exit updated
NL	GTS	yes	25% reduction for entry and exit tariffs
ES	Enagas	yes	Zero exit tariff and zero entry tariffs
PT	REN	yes	Entry tariff reduced by 97% no update
BE	Fluxys	yes	Exit tariff reduced by about 50%, no reduction of entry tariff updated
Pol	Gaz-System	yes	Up to 80% discount on fixed charges and 100% on variable
Hun	FGSZ	yes	100% reduction on exit and @40% reduction on entry
Cro	Plinacro	yes	90% reduction on entry, 100% on exit
Cze	Net4gas	yes	Up to 98% on exit and 90% on commodity

The main observation to make is that while care must be taken in applying in isolation one aspect of European regimes to the GB market, it can be seen that there is precedent for significant discounts to storage related transmission capacity charges.

5. Conclusions and recommendations

In section 2 of the report we suggested that a change to the TM merit order can be justified on the basis of the correlation analysis we carried out for the 2012-13 and 2013-2014 winter/shoulder periods. The modelling considered two alternative merit orders; an Amended Base case, which shared supply between LNG and MRS reflecting recent flow data; and a High Storage case which promoted MRS above LNG. The effects on prices, both entry capacity and exit capacity showed the high degree of sensitivity of the TM to a change in the underlying supply/demand assumptions, but under both cases produced significant CAPEX savings to the NTS.

The proposed TM merit order can be explored further by industry to arrive at an acceptable outcome, however, the scenarios produced in this report should provide a reasonable guide.

In relation to the removal of the floor price enshrined within the current charging methodology, it can be seen that the broader impact on all system points is magnified when the floor is removed, however, even with its inclusion there are significant improvements in charge levels to storage sites, mainly through reductions in exit capacity charges.

The review of alternative charging mechanisms provides helpful examples of regimes which employ negative charges, or credits, as well as, in the case of other EU gas markets, more significant discounts for storage related flows.

In the case of the GB electricity there are reasonable analogies to be made if one views gas deliveries into the system as ‘negative demand’ - this is conceptually similar to triad avoidance in electricity (consider the analogous behaviour of embedded generators in electricity). Thus parties delivering gas during peak periods at locations where raw LRMCs are negative (perhaps restricted to gas storage) might be rewarded at the level of deliveries made during those peak periods. Payments could then be made to such parties at the end of the regulatory year.

For example an annual capacity charge payment could be made to users based on the average delivery made at a relevant entry point during the year 1 April to 31 March on days:

a) where overall system demand is greater than 85% of the 1 in 20 peak demand; or
b) where a) does not apply in a given year, the highest three demand days between (say) November and February.

The gas DN entry capacity arrangements are less clear-cut, however, they do permit the application of negative charges based on the premise that the connected entry points provide benefits to the local network. The charge/credit is applied in the form of a commodity charge even though the formula employed to calculate the rate includes elements which are essentially capacity related i.e. the ECN credit and the LDZ credit. This approach to charging for capacity-related elements could be considered in relation to charges applied at storage.

The proposal to modify the TM merit order can be pursued independently of any push to seek a redistribution of the NTS benefits provided by storage and therefore, attributable to it, as they are not intrinsically linked. On this basis, it can be argued **that additional** reductions in charges should be applied for storage sites. For example, given the potential range of CAPEX savings it could be argued that flows to and from storage facilities should not incur any transmission charges. The fact that storage related flows are exempt from paying TO Commodity charges should not be confused with the benefits which can be ascribed to them. The exemption from all commodity based charges is justified on the simple basis that gas which is delivered to, and redelivered from storage facilities will incur these charges on first entry to the NTS and then again on exiting the system – with storage facilities considered as being embedded within the system and gas stored in them, parked for later redelivery. The imposition of these charges would result in each unit of gas being double charged prior to delivery to the final customer.[29]

It should be noted that the analysis carried out in this report focuses purely on network CAPEX savings, ignoring the potential OPEX savings which could also be "assigned" to storage. Such savings could include, for example, a reduced need for and more efficient use of compression due to the location of storage being closer to the centres of demand. If such savings can be shown to exist, then it is arguable that the zero rate of SO commodity charge currently applied to storage flows is at best reasonable but potentially insufficient and similar to the DN entry arrangements should attract a negative rate.

Certainly, as a minimum there is evidence to suggest that storage flows can and should be treated differently to flows at other system points. The current exemption from commodity charges is well justified and is only valid at storage, insofar as the same unit of gas which is offtaken from the NTS is later delivered back to the NTS.[30] The fact that there are further non-captured benefits which can be derived from CAPEX and, we suspect OPEX savings, provides a basis for defending, as well as challenging, the current charging regime. Certainly, the transmission tariffs targeted at storage users are higher than those applied in many other Member States.

In summary, our recommendations are as follows:

i) Consider proposing changes to the supply merit order;
ii) Consider potential for negative capacity charges or simply removing all transmission charges currently applied at storage;
iii) Consider application of ex-ante credits for storage flows akin to those applied at DN entry points;
iv) Consider potential for the application of a "corrective" ex post credit to storage users delivering gas on peak days;

In the event that any of the above recommendations are pursued, with the exception of recommendation (i), then a case will be need to be made as to why storage should be made a "special case". In addition to the fact that there is precedent for storage to be treated differently, as is the case with the non-application of commodity charges, other arguments will need to be presented, or alternatively similar arrangements should be applied at other entry/exit points which can be shown to deliver benefits to the system. Other arguments which promote the unique nature of storage are likely to be somewhat subjective in nature, but might include, by way of examples, the following:

[29] See National Grid "Overview of Gas Transmission Charges" February, 2012
[30] Unlike interconnectors where gas is exported and consumed and does not return to the originating network.

a) The EU Tariff Guidelines make specific reference to the fact that transmission tariffs relating to storage can be set to reflect the benefits which storage facilities provide to the system. The absence of any reference to any other facilities, in this regard, implies that "special treatment" of storage and only storage is envisaged at the EU level.
b) Unlike any other points on the system, storage sites offtake gas on relatively low demand days and deliver gas on relatively high demand days (relative to the duration of the period within which they typically cycle). They are unique from that perspective and in combination with the above point qualify for different treatment.
c) Storage provides a greater contribution to security of supply (a system benefit) than most other connected facilities. They tend to be embedded within the system with no direct access to other markets
d) Storage provides significant levels of flexibility which is not recognised within the current balancing and charging arrangements. This is of benefit to the system in relation to linepack management.
e) Although not strictly related to transmission benefits, it could be argued that as storage has a price dampening effect on prices – through time shifting of deliveries – that the costs of balancing the system are reduced. These savings will be realised by shippers, through the price deflationary effects, but also by the TSO through the costs it will incur in taking balancing actions on the OCM, or the procurement of other balancing services available to it.
f) On a general level, it could be argued that transmission tariffs are a barrier to storage investment and the longer term benefits which storage will provide to the system will not be realised. Parallels could be drawn with the EMR capacity arrangements which are being put in place to ensure that the benefits of the future operation of CCGTs are realised, but only if the necessary changes are made well in advance of the "need".

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Appendix 1 Deriving electricity transmission charges

The Transport model

It is the transport model that calculates the locational component of the TNUoS tariff. NGET use a DC load flow model known as Investment Cost Related Pricing (ICRP), which is conceptually similar to the gas long run marginal cost (LRMC) methodology that is the basis of National Grid Gas Transmission's (NGGT's) transport model.

The transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point (or node) on the transmission system, based on a study of peak conditions on the transmission system, i.e. using the electricity Ten Year Statement (TYS) forecast demand and generation background.

The model[31] is available for users to make their own assumptions, test their own scenarios or consider the impact of a particular new load on the system.

In the transport model investment costs are expressed in terms of MWkm and the relative investment costs of other circuits is referenced to a 400kV overhead line. That is, different voltage circuits are expressed in terms of a 400 kV overhead line, e.g. a 275 kV line would be stated in equivalent terms by factoring up by 1.1 times, to give 10% more MWkm. This is similar to the gas model insomuch as distance is used as a proxy for LRMC's.

MWkm is the concept that ICRP uses to calculate marginal costs of investment. Hence, the marginal cost is estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for an increment of 1MW power injected on a node the system (with a corresponding 1 MW of power removed at a reference node).

In summary the ICRP methodology derives a 'true' long run marginal cost for adding additional generation at a particular node on the network. This would be positive where additional investment was required to accommodate the new generator or negative if future investment in the network could be avoided. The marginal cost for demand at a particular node is the negative of the generation value.

Tariff model

We now turn to adjusting the raw marginal cost values derived from the ICRP methodology.

Step 1 – calculate weighted MWkm

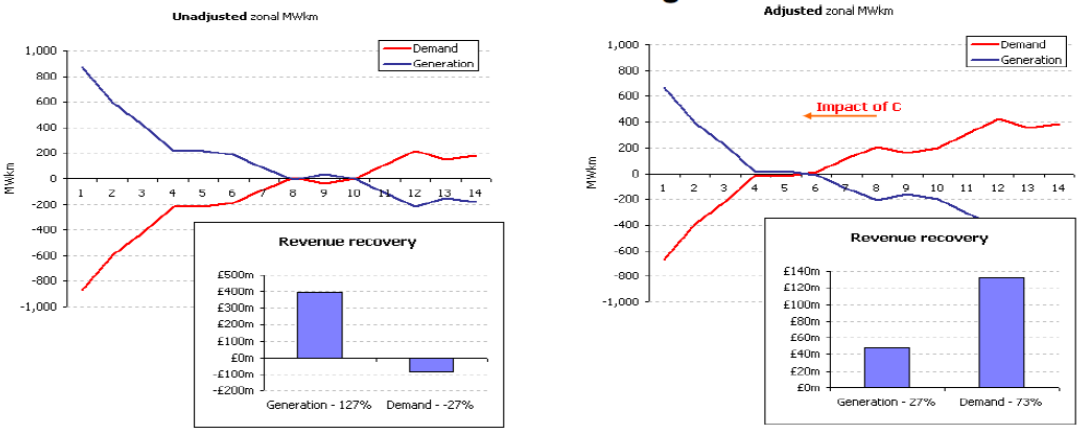
Some simplification is considered necessary, so nodal MWkm are grouped together into zones and weighted zonal MWkm calculated. It is important to note here that there are different zones for generation and demand. Generation zone boundaries can vary from time to time whereas demand zone are 'fixed' and correspond to historical electricity distribution network areas.

[31] The DC load flow ICRP transport model is available from NGET on request.

Step 2 - Convert weighted MWkm to £/km
Zonal weighted MWkm are then converted into £/km values by multiplying by an Expansion Constant (EC), which represents the annuitised value of 400kV overhead line transmission infrastructure capital investment required to transport 1MW over 1 km; and a further Global Locational Security Factor (GLSF) representing the extra build needed to allow for faults (e.g. lightning strikes).

Step 3 – Correct revenue split
The next step is to allocate charges; 27% to generators and 73% to suppliers. This split was agreed at the time of privatisation of the electricity industry in 1989; it is essentially a one quarter to three quarter split if one account for transmission losses on the system.

Figure 8 – Electricity Transmission charges revenue adjustments



This adjustment is achieved be adding a fixed constant to the weighted MWh to ensure the right 27:73 split of revenue recovery, illustrated in the figure 8 above.

Step 4 - Calculate local charges
Local charges are those that are specific to particular generator such as the local substation and circuit used by that generator. These are added to the correct values derived in step6. Such user specific charge components are not typical in gas.

Step 5 – Add fixed residual component
The total charges recovered at stage 4 amounted to around 20% of the revenue that NGET recovers on behalf of relevant GB TSOs in 2012/13. This recovery of 'missing money' requires a flat 'non-locational' charge to be added reflecting the 27:73 charge recovery split. In 2013/13 this additional residual component amounted to Generation = £3.48/kW; Demand = £18.56/kW.

Use of system charges across Continental Europe tend to place less emphasis on recovering transmission use of system charges from generators; indeed many EU member states recover all these charges from demand.[32] Greater harmonisation of transmission charging arrangements across the EU is likely to lead to a progressive reduction in the proportion of GB charges recovered from generators. It is important to note, however, that this does not necessarily mean a move away from locational charges, as it is perfectly

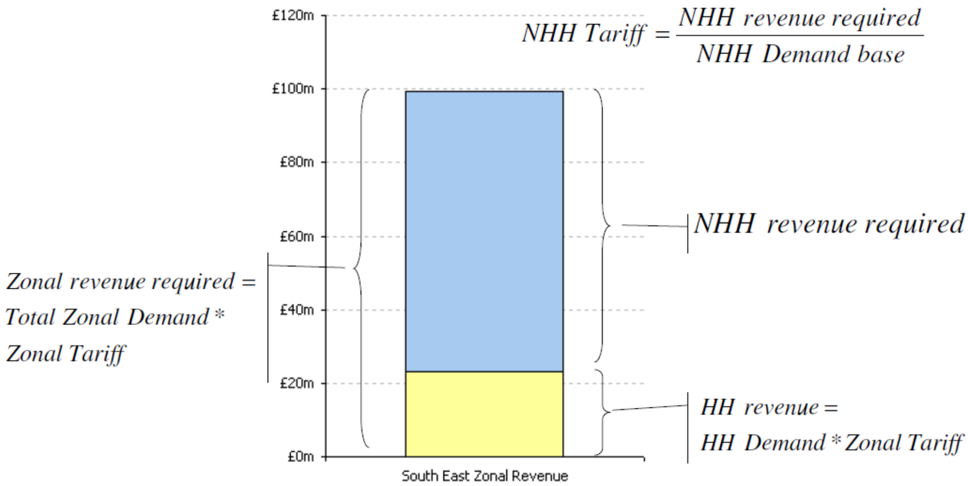
[32] It should be noted that a number of member states however at the same apply 'deeper' connection policies where more significant proportion of transmission costs are recovered from connection charges.

possible to devise a regime in which average revenue recovered from generators (G_{ave}) equals zero.

It is also worth noting that the residual component described above also covers the cost of the “small generator discount”, which applies to small generators in parts of GB. This adjustment addresses the apparent concerns of small generators connected to the 132kV system in Scotland, which was classified as a transmission asset, and therefore faced transmission charges with the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005.

Step 6 – Calculate non half-hour (NHH) tariff
The NHH revenue is determined by deducting the expected revenue from half hour customers (using the tariff derived at step 5) from the total revenue required for that zone. The NHH tariff is based on that NHH revenue divided by the relevant NHH demand base. This is illustrated in figure 9 below:

Figure 9 – Calculation of NHH revenue



Intermittent generation and use of the system

Fundamental changes to the TNUoS charging methodology are expected once Ofgem approve Connection and Use of System Code (CUSC) modification CMP213 Project Transmit TNUoS Developments.

NETS SQSS now reflects the fact that some investment in incremental transmission capacity varies with the output characteristic of different classes of generator, i.e. investment is now less driven by peak capacity requirements. The main driver for this has been the impact of intermittent generation on the transmission system.

Wind farm power output is dependent on wind speed and it also unlikely that all wind farms, even within a particular region, will be running at maximum output simultaneously. At times such plant will be displacing non-renewable generation. The concept of system “sharing” is therefore introduced by CMP213.

CMP213 would achieve this by applying a year round charging component which varies with annual load factor alongside the existing peak security component. The CMP213 workgroup considered many different sharing options each of which are now being considered by Ofgem. What is clear, however, is that implementation of CMP213 will generally dampen charge differentials (going from positive to negative charges) across the GB, and will lead to different classes of user being treated differently (this may be due or undue discrimination depending on your view).

Triad

TNUoS charges are designed to provide locational pricing signals to new demand or generation wishing to connect to the system. This, in theory, will ensure more efficient development of the system, as investors include such costs or benefits (in the case of negative charging zones) in their overall evaluation of the economics of particular projects.

In addition, however, the TNUoS charging regime also seeks to discourage the demand side from utilising the system when the system is under stress and generation capacity margins are tight. Such financial incentives are thought to reduce peak demand by around 1 GW. NGET achieves this by only charging half hourly (HH) metered demand based on consumption during certain periods. These periods are collectively known as Triads.

Triad demand is measured as the average demand on the system over three half hours between November and February (inclusive) in the year 1 April to 31 March. These three half hours comprise the half hour of system demand peak and the two other half hours of highest system demand which are separated from system demand peak and each other by at least ten days. Thus a customer reducing their demand to zero in these periods will face no use of system charges, though they may have had to reduce demand many times to capture these specific three periods in a winter.

Embedded generators contribute to a suppliers' Triad avoidance as they as they are included in the supplier's base balancing mechanism unit (BMU) volume as a negative demand thus reducing the overall value of the demand.