SO Incentives Consultation – Points of Clarification (Gas)

During the consultation process a number of points of clarification have been raised with us. This note summarises our response to these points which may further assist parties in assessing the proposals and issues raised by the consultation.

Overall Costs

The concept of an overall incentivised cost (to compare with the electricity BSIS target) is potentially misleading for a number of reasons, the main ones being:

- The total shrinkage gas (and electricity) cost will be set over a period of time as the price of gas varies. No 'starting assumption' is made within the methodology as is the case for BSIS.
- BSIS includes the costs (and adjustments) which relate to residual balancing. In gas these costs are recovered through the UNC neutrality arrangements and not through the SO commodity charge.

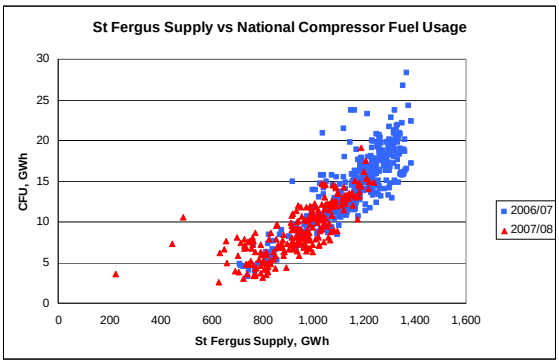
However using gas and electricity prices for deliver period 2008/09 that were prevailing at end November 2007, the Shrinkage costs (assuming St.Fergus flows of 95-100mcm/d) would equate to £116m. Combining this with the middle option on Operating Margins Costs of £23.5m gives a total close to **£140m**. This excludes any potential out-performance through incentive schemes, which would, whilst generating incentive revenue for National Grid through sharing factors, **reduce this total cost**.

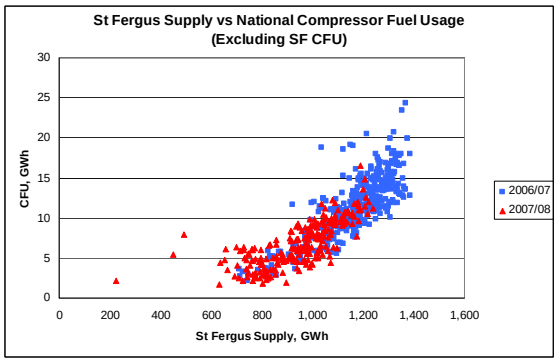
Compression at St. Fergus

Our forecasts for Shrinkage include the legacy compression requirement at St. Fergus which takes gas out of the TOM terminal at 40 bar and then compresses it up to 75 bar. Whilst we own the compressors and procure the energy to cater for this requirement as part of shrinkage, we do not directly control the operation of the compressors.

National Grid procures energy in aggregate to cover the total shrinkage requirement (including the St. Fergus compressors). The costs associated with the compressors at St. Fergus are charged to Shippers at the St. Fergus terminal, so they are deducted from the amount recovered from all shippers through the SO commodity charge. National Grid's price control has historically deemed this recharge to be SO revenue and thus required an SO revenue allowance and has been accounted through the shrinkage incentive since 2002.

The correlation analysis which underpins linking St. Fergus flows with National Compressor usage has been repeated, excluding the St Fergus compression to test the correlation. The results show that the correlation with St Fergus supplies remains strong (data in spreadsheet on website).





Electric Compressors

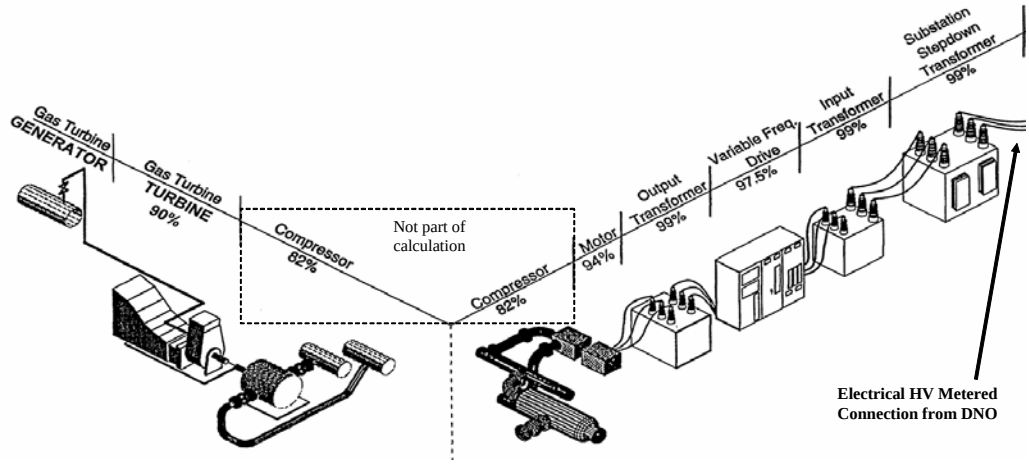
Our forecasts of compressor use going forward are based on historical use of gas turbine driven compressors. As a number of these gas turbines are being replaced by electric drives going forward, an assumption must be made as to what the reduction in gas requirement will be and what new electricity requirement will replace it.

Clearly, the energy procured to run an electric drive is a 'delivered amount' i.e. after the process of burning a fuel in a power station (at a certain efficiency) and transported to site (at a certain efficiency). In contrast, the energy procured to run a gas compressor has to account for the efficiencies of the entire process of associated with converting the fuel into mechanical work through the turbine.

The conversion factor of 3 units of gas to 1 unit of electricity we have assumed in our forecast is based on the relative efficiencies of the gas turbines and the on-site electrical installations for electric driven compressors. Note this assumption doesn't affect the overall compression requirement, only which 'pot' (either gas or electricity) the volume is attributed to and hence whether the gas or electricity reference price is used to derive the cost.

In any particular instance, the exact efficiency ratio will depend on a number of factors such as the specific application, operating profile (base load, part load) and process conditions. The assumed efficiency for RB211 is approximately 29.7% (33% gas generator efficiency x 90% power turbine efficiency at 80% load conditions). Modern variable speed electric motor drives have an efficiency of approximately 88.9% at 80% rated load hence, to model the relative energy requirements over a 12 months operating range, we have calculated the ratio between gas and electricity requirements as 88.9/29.7 = 2.9966 (rounded up to 3:1).

COMPARISON OF GAS TURBINE & ELECTRIC DRIVE COMPRESSOR NET THERMAL EFFICIENCY FOR 80 % LOAD CONDITIONS



RB211 = 0.33 x 0.9 = 29.7% Efficient

Electrical Drive = 0.94 x 0.99 x 0.975 x 0.99 x 0.99 = 88.9% Efficient

The arrangements (including emissions related issues) associated the changeover of certain compressors from gas to electric drives was dealt with as part of the recent TPCR process, which National Grid has accepted as a package, and is therefore not relevant to the SO incentives consultation.

It may be possible to operate gas compressors in preference to electric compressors for triad avoidance purposes, to reduce TNUoS costs. Until we have some operational experience we are unsure as the extent to which this is possible. Assuming it is, an assessment would have to be carried out to weigh-up the various costs involved against potential savings – which is consistent with what the incentive is trying to achieve. The extent to which our strategies can deliver savings will be shared between National Grid and Shippers through the incentive scheme sharing factors.

Electricity Procurement

Procurement
National Grid will procure the electricity for the new electric drives through a standard flexible supply contract. This allows a limited degree of flexibility to procure the required amount of electricity through the supplier over a period of time at prevailing market prices.

In practice, the supplier costs up the given load profile for the period in question against forward market prices prevailing on the day the contract is struck. The additional costs or revenues generated by flexible procurement (as time goes on and as market prices vary) is effectively charged or refunded against this initial cost.

Electricity Reference Price Methodology
Our proposed electricity reference price methodology is to set the reference price using baseload wholesale seasonal prices for 2008/09 averaged over the period 1st-31st March 2008 (plus a retail uplift), which is the period when we will enter into a contract for the new compressor load profiles.

The extent to which we then exercise flexible procurement under the contract will dictate whether our actual costs are higher or lower than the reference price allows – i.e. it mirrors how the supplier treats the costs or revenues generated by flexible procurement against the initial quoted cost.

The principles and strategies associated with managing price risk associated with shrinkage procurement are likely to be the same whether procuring gas or electricity, hence we believe this is an appropriate way to manage electricity costs. In the same way as for gas procurement, any savings or additional costs measured against the benchmark will be shared between National Grid and Shippers through sharing factors.

CV Shrinkage

Where CV shrinkage can be caused by an issue beyond National Grid's control we have proposed that any CV shrinkage incurred should be excluded from the incentive arrangements. This potentially includes CV shrinkage caused by the impact of terminals close to offtakes where the CV of gas from that terminal is particularly low or high when compared to the gas seen in the remainder of the network and where there are no co-mingling streams available to National Grid to manage the issue. A good example of this is at Teesside where the Cowpen Bewley offtake sees the CV of the gas brought in directly from the terminal whereas the CV of the offtakes within the rest of the LDZ is influenced by the CV of gas from St Fergus. A similar issue may occur at sites near to other terminals however there is a particular risk at Teesside due to the lack of diversity in supplies from the terminal and the topology of the system in the area.

Where the risk of CV capping occurs National Grid (NTS) will take any operational action available to it to mitigate the risk. This includes working with the relevant DN to assess if there is an option for the DN to shutdown the offtake at which CV capping is likely to be initiated and source the gas from an alternative offtake. The UNC Offtake Arrangements Document section I 2.4 clarifies how such an arrangement should be managed in the overall interests of operating an economic and efficient system, although as it states in the document the actions cannot be guaranteed given that safety and efficient operation of the LDZ need to be taken into account before such an action can be agreed upon. It is also the case that such actions are not applicable at all offtakes, and are subject to limitations due to demand levels.

With respect to the management of CV shrinkage issues in relation to Milford Haven, should CV capping occur in the West Midlands LDZ due to the Ross Offtake, we understand that the opportunities for shutting down the Ross offtake to mitigate CV shrinkage risks are severely limited due to the size and location of the Ross offtake. Hence there are no practical steps that can be taken between NTS and DN to manage flows through Ross should CV Shrinkage occur given the current CV capping rules.

For entry points embedded within LDZ's, the process for deciding on the CV of the gas entering the network is defined within the contractual agreement between the owner/operator of the entry point and the owner of the relevant DN network. This will be based around the best mutual arrangements for the two parties with National Grid NTS having no formal role to play in setting this CV level under current market arrangements. The concerns of the NTS shrinkage manager with respect to the impact of mod154 in formalising the process for direct entry to DN networks were outlined in our response to the modification proposal, and we believe this issue

reinforces the argument for a wider review of the CV capping arrangements under the FWACV process defined with the Gas Thermal Energy Regulations.

The options for National Grid NTS to contract with the embedded entry point to enrich the gas entering the LDZ (assuming this is possible) may for one cut across the contractual arrangements with the relevant DN and also introduce perverse incentives on the entry point to deliver low CV gas into the network in order to access an additional revenue stream.

Unaccounted for Gas

Unaccounted for Gas on the NTS is generally driven by cumulative metering uncertainty and metering errors spread across the 200+ entry and exit meters measuring the gas entering and leaving the NTS. National Grid NTS has direct ownership of less than 1/6th of these meters, the others being owned and operated by the various site owners and the Distribution Network Operators.

The level of UAG can vary significantly from year to year due to the occurrence of random errors at sites, the configuration of the system, demand levels and supply configurations. However, over time the underlying level of UAG has fallen. At the time of the introduction of the incentive schemes in 2001/2 the underlying level of UAG was between 1600 and 2000GWh/yr compared with the figure of 1200GWh/yr that we are now experiencing. A significant element of this reduction is due to the initiatives National Grid has undertaken to identify meter errors at sites and work with meter owners to improve the operation of the sites. Going forward National Grid recognises that we cannot stand still and that further reductions in the underlying UAG level should be sought.

This element of the incentive is not one that can be resolved within a single year as many of the drivers relate to the design of sites, the assets that are in place at the sites and the standards that are adopted to define the measurement of gas through the sites, coupled with a diversity of asset ownership, and the various incentives and regimes governing asset management. However we believe there are opportunities to drive improvement through the adoption of best practice by all asset owners, and under the incentive regime and rights and obligations placed on National Grid within the UNC and the various contractual relationships, we would hope to influence asset owners to ‘do the right thing’ to drive down the underlying level of UAG going forwards.

Other activities that we would look to undertake in this area is to proactively search for extant meter errors, work with meter asset owners to ensure metering validations and audits are carried out appropriately and reconcile errors that have been found quickly, accurately and with an appropriate level of transparency for the community.

Operating Margins

Requirements for Operating Margins gas are determined through network simulation analysis. Important factors in determining the requirement include the location and volume of supplies, the physical network in place and statistics relating to the reliability of compressors. The 15% reduction in Operating Margins requirements for 2008/09 reflects a number of changes to the system from 07/08 including the anticipated commissioning of Milford Haven, Isle of Grain phase 2 and Aldbrough Storage facility. It also reflects new NTS infrastructure such as the Easington to

Nether Kellett pipeline. We have not assumed any potential increase in reliability of compressors to reflect the commissioning of electric drives as until these are commissioned and demonstrate proven reliability we do not believe it is prudent to do so. In future years, if electric compressors demonstrate higher reliability than gas compressors, then we would expect this element of the operating margins requirement to decrease.

Residual Balancing

We believe that the residual balancing activity and associated incentives should be reviewed beyond 2008/09 to consider whether the arrangements in place are appropriate given the current market environment. Therefore we have not considered more complex changes to the incentive arrangements for 2008/09 other than those presented in the consultation.

In relation to providing an option to remove the linepack incentive, this was driven by representations made to Ofgem's initial thoughts consultation and does not reflect National Grid's view that the linepack incentive should be dropped. Performance under this element of the incentive has been difficult due to the tight nature of the target (which effectively has tightened every year since it was established as the total system linepack has increased) and the interaction with other considerations underpinning system operation. However we do have operational strategies in place which attempt to minimise linepack change day-on-day and we proactively endeavour to actively manage linepack in accordance with the incentive.

Changes in total system linepack are shown below:

Aggregate linepack		Average Linepack	Annual Change
	Oct-05	281.9	
	Oct-06	289.1654839	7.265484
	Oct-07	298.5312903	9.365806
	Oct08 forecast	326.2812903	27.75

Linepack Increases	
Oct 06 to Oct 07	Panal Nether Kellet - 7 mcm @OP.
Oct 07 to Oct 08 Assumptions	Milford Haven 40.5 mcm @MOP assumption operating half of this
	Easington to Ganstead and Asselby Panal - 7.5 mcm OP assumption

To put the £3.5m incentive caps/collars into context, the overall gross value of balancing actions over the past few years is:

2004/05: £90m
2005/06: £65m
2006/07: £55m

Additionally, cashout prices are potentially affected by any energy balancing actions that we take and therefore consideration should be given to this in terms of the behaviours that the market wants the SO to adopt through its incentives.

Information Incentives

Since the introduction of the demand forecasting scheme, National Grid has been incentivised to improve the D-1 '13:00' forecast to industry participants. Not simply a mechanical process, the task of increasing the accuracy of this forecast has brought into focus a number of inter-related aspects which have to combine to give the market this forecast. This includes the human factors such as additional resource with Control Room integration / training, investment in systems and modelling

analysis together with further research into the underlying dynamic drivers of demand and the input data which feed these correlations.

Specifically, these developments have included Control room monitoring, developing and refining the underlying forecasting models, Improved component modelling (particularly in generation patterns), together with refinements to weather interactions and holiday effects.

Going forward the task of maintaining and improving demand forecasting accuracy levels is a continual process with the need to continuously update and 'train' these models over recent data. We believe forecasting is implicitly getting more difficult due to the nature of market developments and under an 08/09 incentive we would be looking to evolve data collection, more advanced modelling - in particular interconnector, storage flows and generation changes - and establishing this in robust business processes supported by systems developments as appropriate.

In terms of the information publication element, National Grid delivers a wide range of gas market information to users via its website. This is delivered through UNC/Licence obligations and/or voluntary market agreement. Through the proposed incentive arrangements National Grid could look to deliver additional value to users, over and above what it is obliged to do, by carrying out work to improve timeliness of publication of information (i.e. reduce the latency between the information becoming available in a core system such as GEMINI and the time it is published on the website) and to improve the availability of the information for users.

For 2008/09 we believe that further improvements could be made over existing performance levels by 1) improving the interfaces and communication routes with the core systems such as iGMS and GEMINI to improve the timeliness of data published on the site, and, 2) providing additional resilience and load management at the front end of the systems to improve the availability of the system for users, therefore

- timeliness improvements can be achieved across the range of data items published by replacing some of the key interfaces between systems and rationalising data flows between the core system and the publication system. If a 2 year option was chosen then National Grid would also look to modify core systems to make the data available earlier and to simplify information interfaces.
- Availability can be achieved by introducing additional load balancing functionality between webservers, further automation of failover, introducing additional servers, upgrading site bandwidth, migrating some services to a new internet gateway, and introducing services for managing bandwidth utilisation and misuse protection.

These developments are not funded through the price control and are not part of any other project. We have not proposed incentive options with explicit downsides as (particularly with the one year option) it will take time to deliver these improvements and an explicit downside would not recognise this and National Grid would potentially be starting from a negative position with a diminishing period over which to recover its costs and potentially earn incentive revenue.