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Methodology to Determine Incremental Constraint Management Costs and Incremental Compressor Costs Related to Removal of an NTS Pipeline

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PART A: General

a. Background

1. National Grid Gas plc "NGG" in its role as holder of the Gas Transporter Licence in respect of the NTS (the Licence") is considering the sale of an existing NGG pipeline to a third party for purposes other than the transportation of natural gas. Any sale will be subject to various terms and conditions, including protection of NGG and its customers from potential increased costs resulting from the pipeline disposal.

2. Removal of a pipeline from the NGG gas network may increase the chance of a constraint[1] occurring, or the cost of a constraint that would have occurred, on the gas network in the location of the relevant pipeline, particularly if flows are high. If a constraint does occur, NGG has a number of tools available to it to alleviate the constraint, currently these include:
    - Scaling back of interruptible entry, and off-peak exit, capacity rights;
    - Locational gas buys and sells on the OCM;
    - Buy-back of firm NTS Entry Capacity rights from Shippers at constrained Aggregate System Entry Points ("ASEPs");
    - Use of other capacity tools, such as Capacity Management Agreements, referred to in National Grid's System Management Principles Statement.

3. In accordance with the Licence, constraint management costs are shared by NGG and Shippers. Hence, notwithstanding that NGG is incentivised to minimise these costs, the disposal of an NTS pipeline has the potential to increase both NGG's and Shippers' costs and hence prices to consumers if a constraint were to occur. This statement details the methodology that will be applied to determine such increases in costs so that, subject to the terms of any sale agreement, the costs can be passed on to the third party to whom the pipeline is transferred.

4. In addition to the increased risk of constraints, the removal of a pipeline will require remaining infrastructure to work harder. This is due to the lower capability of the NTS with the relevant pipeline removed; resulting in greater pressure losses down the remaining feeders. This will result in additional fuel (gas or electricity) usage by, and maintenance of, the affected compressors. Hence, the cost of increased compressor operation also needs to be determined and passed to the third party. Such costs will be assessed in accordance with this methodology.

5. Although it may be preferable, by providing a degree of certainty, for the third party to pay a lump sum amount as part of the pipeline sale to cover future constraint management and compressor costs, this would only pass the risk of uncertainty to NGG and Shippers. It is assumed that this option is not acceptable to NGG and its customers; hence the methodology identifies an on-going process to determine actual increases in costs. Where, in specific circumstances, such one-off payment is acceptable, this methodology will not apply.

6. Any incremental costs covered by this methodology statement that are incurred by NGG as a result of the disposal of an NTS pipeline will be excluded, to the extent that such costs are recovered in accordance with this methodology statement, from any incentive arrangements detailed in the Licence. Hence NGG and Users will not be exposed to increased costs resulting from incremental costs breaching any cap or collar applying to such incentives, or from any changes to the cap, collar or sharing factors.

[1] A constraint can occur at an NTS Aggregate System Entry Point (ASEP) or at an NTS Exit Point. References to constraints and constraint management actions refer to both entry and exit points unless specifically stated and/or the context dictates otherwise.

7. To facilitate this, any revenue received from the third party in respect of costs defined in this statement shall be channelled to the appropriate revenue stream to balance the costs incurred. It has been assumed that any necessary changes, if any, to the Licence and/or Uniform Network Code ("UNC") to allow revenue flows will be implemented. It is proposed to await the outcome of the Department of Energy and Climate Change "DECC" Carbon Capture and Storage competition before addressing the necessary changes.

b. Key features of the methodology

8. Within the overall aim of identifying incremental costs, the key features of this methodology statement are to:

   (a). Provide a process to ensure the reimbursement of NGG (and hence Users and consumers) for any incremental compressor fuel usage (CFU), maintenance and emissions related costs and constraint management costs attributable to the disposal of a pipeline;
   (b). Allow for the identification of relevant system constraint locations (i.e. ASEP(s) and/or NTS Exit Points). Only incremental constraint management costs manifested at these system points will be assessed[2]. See annex 3;
   (c). Accurately reflect the incremental constraint management quantities attributable to the removal of the pipeline;
   (d). Provide a transparent methodology to determine the incremental CFU and to apportion such quantities between electricity and gas consumption;
   (e). Quantify incremental maintenance and emissions costs resulting from increased compressor operation attributable to the disposal of a pipeline;
   (f). Determine, as accurately as is reasonably practicable, the prices involved in managing incremental constraints and obtaining compressor fuel;
   (g). Provide an approach to verifying and auditing the resultant costs; and
   (h). Facilitate the determination of additional costs to account for the manpower resource required to undertake any necessary analysis work.

9. Subject to paragraphs 10, 76 and 82, the methodology shall be fixed at the time of the pipeline sale. Subsequent changes to the methodology will be by agreement between NGG and the relevant third party. However, the methodology may be revised by NGG in the light of experience and the revised methodology applied in respect of future pipeline disposals (if any).

10. In the event of major changes to the capacity regime it will be necessary to review this methodology such that relevant incremental costs continue to be charged to the third party. Any changes arising shall be implemented only following industry consultation.

c. Validation of analysis: auditing.

11. In order to determine that the analysis has been conducted in a fair manner and in accordance with this methodology, the determined costs may be subject to challenge by the third party and, if necessary, subject to independent verification.

12. Consistent with paragraph 37 NGG will seek to simplify analysis of incremental constraint management costs, and other costs covered by this methodology statement, by making appropriate assumptions. Whether undertaken by NGG or an independent company, the results may be subject to formal challenge by the third party. In the event of challenge, further more detailed analysis shall be undertaken, and where a dispute continues such further detailed analysis shall be undertaken by a different independent analyst whose decision shall

[2] This methodology assumes that any pipeline disposal affects system points independently of any other disposal. In the event that this is not the case a methodology to determine how costs should be shared between relevant third parties acquiring the different pipelines will be required.

be binding. The cost of all validation analysis work shall be borne by NGG if the revised costs, for any constraint period, are less than the lower value calculated from:

- 85% of that originally calculated, and
- £50,000 below that originally calculated,

otherwise the costs shall be borne by the third party.

13. In respect of incremental CFU costs, for the methodology described in Part C only, the third party may, but is not obliged to, request an explanation of the model and assumptions used to generate the lookup table. Where the third party disputes any aspect, and agreement cannot be reached on the need for changes, a mutually agreed independent analyst shall be appointed to determine on the model to be used and to generate the lookup table. The cost of the analyst shall be borne by the third party. Such request must be made prior to removal of the relevant pipeline and with sufficient time to resolve any disputes. Subsequent requests will be limited to one per gas year (Oct-Sept). Once agreed, further retrospective challenges in respect of the accuracy of the lookup table will not be permitted unless otherwise agreed by both parties. However, as the look-up table will be updated annually (see paragraph 60) future challenges will be permitted.

14. In respect of incremental compressor maintenance costs, the third party may, but is not obliged to, request an explanation of the analysis and assumptions used to generate the incremental compressor running time. Where the third party disputes any aspect, and agreement cannot be reached on the need for changes, a mutually agreed independent analyst shall be appointed to determine on the assessment of the incremental compressor running time. The cost of the analyst shall be borne by the third party. Such request must be made prior to removal of the relevant pipeline and with sufficient time to resolve any disputes. Subsequent requests will be limited to one per gas year (Oct-Sept). Once agreed, further retrospective challenges in respect of the accuracy of the incremental compressor running time will not be permitted unless otherwise agreed by both parties.

15. The calculated incremental shrinkage (emissions) incentive cost and, notwithstanding paragraphs 13 and 14 above, the calculated incremental CFU and compressor maintenance costs, may be subject to formal challenge by the third party. In the event of challenge, verification of previous assessments shall be undertaken. Where a dispute continues verification shall be undertaken by an independent analyst whose decision shall be binding. The cost of all verification work shall be borne by NGG if the revised costs, over a calendar month, are less than the lower value calculated from:
    - 85% of that originally calculated, and
    - £10,000 below that originally calculated,

    otherwise the costs shall be borne by the third party.

d. Analyst costs.

16. In the absence of the pipeline disposal it would not be necessary to undertake on-going analysis to determine incremental constraint management and compressor costs. Hence it is appropriate that the cost of this analysis is paid for by the third party.

17. National Grid will calculate actual costs to be charged to the third party using:

    - NGG's fully absorbed direct costs associated with undertaking any works, i.e. including appropriate overhead costs. To facilitate this, NGG shall record the grade of the analyst(s) undertaking the analysis described in this methodology and the time taken,

    - individually tendered rates for indirect costs where independent, external analysts are used, and

    - any other costs incurred, not included above and related to the determination of incremental constraint management and compressor costs.

18. For the avoidance of doubt, the third party shall be responsible for:

- all costs incurred by NGG in determining incremental constraint management costs,
- all costs incurred by NGG in determining incremental CFU costs,
- all costs incurred by NGG in determining incremental compressor maintenance costs,
- all costs incurred by NGG in determining incremental compressor emissions costs,
- all costs incurred by NGG for the purpose of validation and auditing, except that these costs shall be borne by NGG where the initial analysis has been challenged and proven to be inaccurate to the extent stated in paragraphs 12 and 15.

e. Additional Costs.

19. In addition to the costs determined in accordance with paragraph 18 any

- costs incurred by xoserve in the management of costs and revenues to ensure correct allocation for Licence and UNC purposes; and
- interest payable to Users in accordance with the UNC (e.g. due to the time delay between third party payments and the actual incremental costs being incurred),

shall be paid by the third party.

f. Duration

20. This methodology shall cease to apply to any pipeline disposals from the earlier of:

- the date upon which the transferred assets would, in NGG's reasonable opinion, and consistent with its obligation to operate in an economic and efficient manner, have been removed from service as a transmission pipeline for the transportation of natural gas; and
- the effective date of any reduction in the baseline quantity of any relevant ASEP specified in Annex 3, other than where such reduction arises as a result of entry capacity substitution.

21. This date provides a proxy for the date of decommissioning of the disposed of assets. At this date NGG (and, assuming appropriate funding, the wider industry) would, in the absence of the pipeline disposal to a third party, bear any costs arising from decommissioning and any incremental costs resulting from a tighter system. Hence, from this date, there is no difference in NGG's costs with, or without, the pipeline disposal, and no further costs should be paid by the third party.

22. The date applicable is as stated in Annex 3.

PART B: Constraint Management Actions

g. Cause of Constraint

23. Constraints, i.e. situations where the capability of the NTS is insufficient to accommodate the gas flows, and/or inputs, required of it, may be triggered for a number of reasons, including, but not limited to;
    - Compressor failure;
    - Maintenance outages;
    - High within day and/or end of day ("EOD") flow nominations; and
    - Profiling of flows.

24. Notwithstanding the factor that triggered the constraint, it is a combination of plant limitations, high flow nominations, and high flows that determine the need for constraint management actions. The disposal of a pipeline should not impact User flow nominations, but does exacerbate the impact of any plant issues. Hence, even if constraints result from, for example, NGG planned maintenance, the absence of the disposed of pipeline will increase (possibly from zero) the magnitude of constraint management actions needed. Therefore, irrespective of the perceived cause of the constraint at the relevant NTS System Point this methodology shall be applied.

h. Curtailment of Interruptible Capacity Rights.

25. Shippers may obtain entry capacity on either a firm or interruptible basis. Interruptible capacity is obtained in the short-term (Day Ahead) and at a discount to firm capacity. Shippers buy interruptible capacity fully aware of the risk of withdrawal of their capacity rights if NGG is unable to accept gas to be input to the system. Hence, although the removal of a particular pipeline from NGG ownership may increase the risk of interruption, no compensation shall be sought from the new pipeline owner in respect of any losses incurred by any party due to the curtailment of interruptible entry capacity rights. Similarly, the relevant Shipper(s) will not be compensated or refunded its capacity, or other, charges.

26. Similarly, where it is necessary to curtail off-peak exit flat capacity rights, no compensation shall be sought from the party acquiring the pipeline.

i. Determination of the Incremental Constraint Management Quantity.

27. This section shall apply to the determination of costs attributable to all constraint management actions listed in paragraph 2, other than the curtailment of interruptible / off-peak rights.

28. Analysis shall be undertaken at a time convenient to NGG. The aim shall be to complete the analysis (excluding any validation analysis due to challenge of initial results) within one month of the end of the month in which the Relevant Gas Day falls. However, NGG shall be under no obligation to complete the analysis and to invoice the third party any earlier than three months after the end of the financial year in which the Relevant Gas Day falls, i.e. any constraints occurring on a Gas Day falling between 1st April Y and 31st March Y+1 will be analysed, and costs invoiced to the third party by 30th June Y+1.

29. Analysis shall only be undertaken in respect of Relevant Gas Days; being Gas Days when constraint management actions were undertaken in respect of relevant NTS System Points.

30. Analysis shall be undertaken by an NGG network analyst or, at NGG discretion, an independent analyst. The cost of the analysis, whether undertaken by NGG or an independent organisation, shall be paid by the third party.

31. Analysis shall be undertaken to model the Relevant Gas Day in two scenarios:
    (a). Without the relevant pipeline, i.e. actual conditions;
    (b). With the relevant pipeline, i.e. conditions that would (so far as it is reasonable to ascertain) have applied had the pipeline been retained by NGG.

32. Appropriate network analysis software shall be used. All recorded parameters (obtained from appropriate data recording systems) and assumptions made in respect of scenario (a) analysis shall apply equally to scenario (b) except where this is not feasible, e.g. linepack. Any such variations shall be recorded.

33. The analysis of scenario (a) shall model conditions experienced on the Relevant Gas Day to reproduce the actual constraint quantity required (Qr). The actual constraint quantity required may be less than the actual constraint quantity taken (Qt). This is because of the need for the system operator to err on the side of caution[3] such that a level of tolerance is likely to occur. Analysis shall be repeated for scenario (b) to identify the constraint quantity that would have been required in the absence of the pipeline disposal (Qp). Constraint quantities shall be determined in units of mscm/d.

34. The incremental constraint quantity attributable to the pipeline disposal and hence to the third party will be determined as:
    - the difference between the actual constraint quantity required (scenario (a)) and the scenario (b) quantity (Qr – Qp); except where the scenario (b) quantity is zero, in which case it shall be the actual constraint quantity taken (Qt).

35. The analysis will be conducted transiently for the Relevant Gas Day. Where constraints span consecutive Relevant Gas Days the analysis may be undertaken as a single assessment.

36. Key system conditions will be checked against the conditions experienced on the day e.g. hourly gas flows and pressures at the relevant NTS System Points and other key locations, e.g. compressor outlets. These conditions will be recorded.

37. Reproducing a Gas Day in network analysis software is a difficult and time consuming task. Consistent with NGG's obligations to operate in an economic and efficient manner, a balance shall be sought between accurately reproducing conditions experienced and avoiding excessive analysis time. Where appropriate, and at the discretion of NGG, assumptions shall be made and analysis curtailed. Any such assumptions shall be recorded.

38. The scenario (b) assessment will determine whether the nominated flow profile for relevant NTS System Points for the Relevant Gas Day could have been accommodated. If it could have been, then all the constraint management quantity and therefore all related costs will be deemed incremental constraint management costs and payable by the third party.

39. Where NGG takes a combination of actions to manage a constraint the sequence of these actions shall be recorded. The incremental constraint management quantity attributable to each type of action shall be determined by quantification of the different types of action in reverse order, i.e. the last actions taken shall be deemed to be attributable to the incremental constraint management quantity. This is demonstrated below.

[3] Notwithstanding the need to avoid uneconomic and inefficient actions.

Constraint Quantity = 100 units
Incremental Constraint Quantity = 75 units

Time	Constraint Action Type	Constraint Action Quantity	Incremental Constraint Action Quantity
18:00	B-B	20	0
19:00	B-B	40	35
20:00	Loc sell	35	35
21:00	B-B	5	5

Incremental constraint quantity due to buy-backs = 40 units
Incremental constraint quantity due to locational sells = 35 units

j. Determination of the Constraint Management Action Price Attributable to the Incremental Constraint Quantity.

40. NGG will take the most economic and efficient action available when managing system constraints. As the constraint quantity increases it is likely that more costly actions will be taken. Hence it is appropriate that, in respect of incremental constraints resulting from the disposal of a pipeline, the costs attributable to the third party should be the incremental costs. However, the available price of any specific action may vary throughout the Gas Day as Shippers become able to release gas or capacity. Hence the price of later actions may be cheaper than earlier actions.

41. The principle outlined in paragraph 39 takes precedence, but where two or more differently priced actions are undertaken at the same time, when determining the prices to be applied to the incremental constraint quantity, the highest priced actions taken shall be attributable (or the lowest priced action for a system sell). As actions are time stamped this paragraph will only apply if two or more actions are taken simultaneously.

- **Locational Gas Buys and Sells**

42. In order to manage system constraints NGG, as system operator, may buy or sell gas from the NTS. This purchase or sale may be conditional on the counter party adjusting its gas flow at a specified NTS System Point, e.g. the constrained ASEP. The Shipper that is the counter-party to the locational buy or sell will receive or make payment for the gas.

43. NGG may need to balance the gas sold/purchased by buying/selling the same quantity of gas on the open market. This may be on the same Gas Day or later. Any gas purchases and sales may not be readily identifiable to a specific constraint.

44. In respect of a locational sell, the prices (p/kWh) relevant to the third party will be the:
    Price of gas sold (Pss). This will be the weighted average price of accepted gas sales, up to the incremental constraint quantity, in respect of the relevant constraint, determined in accordance with paragraph 41.
    Price of gas purchased (Pps). Subject to such purchases being undertaken to balance the relevant locational sell, this will be the weighted average price of the highest priced gas purchases, up to the incremental constraint quantity, on the Relevant Gas Day. Where there are no such gas purchases on the Relevant Gas Day, Pps shall be zero; and
    Incremental Constraint Quantity Price: will be Pps – Pss.

45. In respect of a locational buy, the prices (p/kWh) relevant to the third party will be the:
    Price of gas purchased (Ppb). This will be the weighted average price of accepted gas buys, up to the incremental constraint quantity, in respect of the relevant constraint, determined in accordance with paragraph 41.
    Price of gas sold (Psb). Subject to such sales being undertaken to balance the relevant locational buy, this will be the weighted average price of the lowest priced gas sales, up

to the incremental constraint quantity, on the Relevant Gas Day. Where there are no such gas sales on the Relevant Gas Day Psb shall be zero; and
Incremental Constraint Quantity Price: will be Ppb – Psb.

46. In the event that the incremental constraint quantity price determined according to paragraphs 44 or 45 is negative the costs attributable to the third party shall be zero, i.e. there shall be no payment made by NGG to the third party. In this event, there will be a net gain to capacity neutrality which shall benefit all Users.

- **Capacity Buy-Backs and Other Capacity Tools**

47. In order to manage system constraints NGG, as system operator, may buy-back the firm capacity rights of Shippers. Shippers will then be restricted, or prevented from, flowing gas at the relevant NTS System Point. NGG will make a payment to the Shipper in respect of the curtailed capacity rights. Other capacity tools may be employed in which a Shipper’s rights over a quantity of capacity are restricted. Reference in this methodology to capacity buy-backs refers to all similar constraint management actions involving a specified quantity of capacity.

48. Capacity buy-backs will specify a quantity and unit price.

49. In respect of the incremental constraint quantity, the **Price of Capacity Buy-Backs (Pb)** (p/kWh) shall be the weighted average of the highest accepted buy-backs up to the incremental constraint quantity, consistent with paragraph 41.

50. Pb will be based on the exercise price, i.e. the price paid for the capacity buy-back at the time the action is taken. The option price, i.e. the price, if any, paid to establish the right to buy-back capacity if and when required, is not included in the determination of Pb. It is assumed that the option price would be payable regardless of the pipeline disposal.

k. Determination of Incremental Constraint Management Costs.

51. The third party shall be liable to NGG for the costs attributable to the incremental constraint management quantity. These costs shall be determined as:

ICQ(Ls) * (Pps – Pss) + ICQ(Lb) * (Ppb – Psb) + ICQ(B) * Pb

Where ICQ(Ls), ICQ(Lb) and ICQ(B) are the incremental constraint management quantities attributable to locational sells and buys and capacity buy-backs respectively.

52. An example of the calculation of incremental constraint management costs is given in Annex 1.

PART C: Principles for Determination of Incremental Compressor Fuel Usage (CFU) Costs.

53. National Grid's compressor fleet comprises a mixture of gas and electricity driven units. Consistent with the Licence, when determining CFU any electricity usage shall be converted to gas equivalent (CFUe) through a conversion factor of 3:1 (electricity:gas)[4].

54. The removal of a pipeline from the NGG system is expected to increase the pressure lost down the remaining pipelines. The actual pressure drop will largely depend upon the gas flow rates and the proportion of the initial pipeline capability that is removed. In order to maintain system pressures extra compression may be required, particularly at higher flow rates. NGG currently procures gas and electricity to operate its compression fleet and is financially incentivised to minimise these costs, and operate all assets economically and efficiently.

55. In order to keep gas shippers and consumers whole, it is necessary for the third party to reimburse NGG for the cost of any incremental compressor fuel usage that results from disposal of its pipeline assets.

I. Determination of Incremental CFU Quantity.

56. This requires post event network analysis, as with the methodology for determining incremental constraint management quantity. However, unlike constraint management, the CFU studies will need to be conducted for each Gas Day making this approach very time consuming unless the assessments can be undertaken automatically.

57. NGG has identified two methods that can reasonably be adopted to ascertain the incremental CFU quantity. An automated approach that requires minimal manual input is the preferred method. However, current network modelling is not at a stage to perform the necessary assessments automatically. Hence this approach shall not be used unless, and until, network modelling has developed sufficiently for assessments to be automated and the technology, knowledge and processes are available within NGG. Until such time, the methodology described below, which is based on current capabilities, shall be used. The automated approach is described in Annex 2.

58. Until the automated approach can be implemented, the approach used in this methodology for the determination of incremental CFU quantity uses a lookup table.

59. Ideally National Grid believes that the use of historical CFU provides the most accurate future CFU projections. However, historical data would only provide a projection of CFU for the "with pipeline" scenario. As an incremental value ("without pipeline" minus "with pipeline") is required an alternative methodology is required; National Grid believes network modelling is the most appropriate.

60. On an annual basis, network models shall be set up, with and without the relevant pipeline, and network analysis[5] shall be undertaken over a range of flow rates at a reference node. Where practicable, this will be a specific, named, ASEP. The step in flow rate between individual analysis points shall be determined on a case by case basis as necessary to minimise excessive analysis and to minimise interpolation errors, e.g. in the example below, the analysis at 10 and 20 mscm/d may be omitted, but additional analysis may be undertaken at 75 and 85 mscm/d.

[4] Consistent with the Licence methodology to convert electricity to gas equivalent (Special Condition C8F(2)(g).

[5] The methodology does not use network analysis "without pipeline" in combination with historical "with pipeline" data because using network analysis for both scenarios should lead to modelling inaccuracies (compared to historical data) cancelling out.

61. Live data shall not be used in the development of the look-up table, although it shall in later stages of the approach. Instead, historical data shall be used to determine, as appropriate, entry and exit flows and this will be supplemented with data from existing statutory, commercial, and regulatory commitments, e.g. Assured Offtake Pressures. Inevitably, a number of assumptions will be required, these shall be documented.

62. At each flow rate level the CFU at all relevant compressors (see Annex 3) shall be identified and a lookup table generated (see illustrative example below). All CFU values will be calculated as kWh/d. In respect of electric driven compressors the CFUe shall be determined.

Reference node flow rate mscm/d	Existing CFU (i.e. with pipeline)	New CFU (i.e. without pipeline)	CFU increase
0	0.0	0.0	0.0%
10	10.0	10.0	0.0%
20	10.0	10.0	0.0%
30	10.0	10.0	0.0%
40	50.0	50.5	1.0%
50	100.0	106.9	6.9%
60	160.0	174.7	9.2%
70	230.0	256.5	11.5%
80	310.0	361.5	16.6%
90	400.0	482.0	20.5%
100	500.0	615.0	23.0%
110	610.0	750.3	23.0%
120	730.0	883.3	21.0%
130	860.0	1023.4	19.0%

All numbers are illustrative only

63. The incremental CFU on a particular Gas Day will be determined from the lookup table using the actual flow at the reference node on that Gas Day which shall be obtained from an appropriate system database. A straight line fit shall be assumed between modelled flow rates. These shall identify CFU separated as gas and electricity.

64. The incremental CFU for each Gas Day shall be the incremental CFU for all relevant compressors in aggregate, determined from:

CFUincremental = CFUactual - [CFUwith / CFUwithout] * CFUactual

Where CFUactual is the actual CFUe for all relevant compressors**.**

65. Network simulation software available to NGG does not currently model the energy consumption of electric compressors. Hence in order to calculate incremental CFU quantities for electric compressors the CFUwith / CFUwithout ratio will be assumed to be equal for both gas and electric compressors.

66. As different prices apply to electricity and gas usage, CFUincremental will need to be divided into component parts, i.e. CFUincremental(elec) plus CFUincremental(gas).

67. As electric driven compressors are generally more efficient than gas driven compressors it is likely these will be used as base load. Hence incremental CFU is likely to be predominantly gas. However, incremental CFU may be electricity if these compressors are made to work harder rather than for gas compressors to be started. Additional factors complicate the assessment further, such as
    - Balance between compressor stations that are electric and those that are gas:
    - Planned and unplanned maintenance:
    - Compressors are not always able to run at maximum design efficiency.

National Grid believes that it is impracticable to accurately determine the type of fuel contributing to incremental CFU. Hence a practical alternative is required.

68. Incremental CFU attributable to electricity shall be determined as:

CFUincremental_elec = <u>[CFUe_elec / CFUactual] * CFUincremental</u>

69. Incremental CFU attributable to gas shall be determined as:

CFUincremental_gas = [CFU_gas / CFUactual] * CFUincremental

m. Determination of the Incremental CFU Price Attributable to the Incremental CFU Quantity.

70. In accordance with the Licence (Special Condition C8F(2)), a methodology for determining gas and electricity reference prices is defined as part of the process to determine target costs for the gas and electricity used by NGG's compressors. These costs feed into the shrinkage incentive included in the 2007 Transmission Price Control for the period up to 2011/2012. NGG has no control over these prices.

71. These reference prices shall be the incremental CFU price which shall be applied to the incremental CFU quantities to determine incremental CFU charges to be passed to the third party.

72. In this situation the third party is susceptible to the determination of these reference prices and may gain, or lose out, from the success, or otherwise, of NGG trading activities. However, such reference prices are set in agreement with the regulator and are likely to be a reasonable, but challenging, approximation of the actual prices likely to be obtained by NGG.

73. In the event that in future price control periods the reference prices given in the Licence are re-defined, then the revised reference prices shall apply for this methodology.

74. In the event that in future price control periods there are no reference prices given in the Licence (e.g. there is no shrinkage (and/or compressor fuel use) incentive), then the latest methodology for determination of reference prices, as defined in the above condition or any superseding condition, shall apply for this methodology.

n. Incremental CFU costs attributable to the third party.

75. The costs attributable to the third party shall be:

CFUincremental_gas * CFUgas_ref_price + CFUincremental_elec * CFUelec_ref_price.

Part D: Principles for Determination of Incremental Compressor Emissions Costs.

76. The costs determined in accordance with this Part D are based on the legislative and regulatory regime at the time of drafting. In the event of significant changes this part shall be reviewed and modified as appropriate.

o. EU/UK Environmental Obligations

77. Consistent with all major energy using plant, gas and electric driven compressors fall within the scope of a range of emissions legislation and NGG incurs costs in respect of managing compliance.

78. Currently, these costs and revenues are borne totally by NGG outside of the Licence. As a result Users and consumers are not impacted by these costs and hence are not considered relevant to this methodology statement.

79. It is expected that any future changes in this area should take account of any pipeline disposals, thereby avoiding the need for changes to the methodology.

p. Shrinkage Incentive

80. The shrinkage incentive in the Licence includes a component for compressor fuel use. Incremental compressor fuel usage is covered by Part C. However, the incentive includes an adjustment for the "shadow price of carbon".

81. Hence the third party should compensate NGG (and therefore Users and consumers) for any losses occurring against this incentive. These costs shall be determined as:

Incremental Shrinkage (emissions) Incentive cost =

[CFUincremental_elec + CFUincremental_gas] * SPCU

Where:
CFUincremental_elec and **CFUincremental_gas** are determined in accordance with Part C;

and
SPCU is the uplift required to reflect the shadow price of carbon, as defined in the Licence.

82. To the extent that this incentive is revised as a result of on-going review, e.g. shadow price of carbon has been updated in government policy to a "traded cost of carbon", the above calculation shall also be revised.

q. NTS Environmental Incentive

83. The NTS Environmental Incentive in NGG's Licence (Special Condition C8F section (6)) covers the venting of natural gas in the operation of compressors. Although the scope of the incentive may be widened in future, for the purpose of this methodology statement only venting from compressors is relevant.

84. Venting from compressors is mainly related to its mode of operation; specifically how many times the compressor is pressurised and de-pressurised. This in turn is related to the number of times the compressor is started. The running and pressurised hours are also factors.

85. Incremental compressor operation, as a result of pipeline disposal, can impact venting in both a negative and positive manner, e.g. increased compressor use may decrease the start-up frequency by providing a more constant load. Alternatively it may require an additional compressor to come on stream. As a result NGG has concluded that the impact on the current incentive of the disposal of an NTS pipeline is unlikely to justify the cost of determining and recovering the incremental cost.

86. NGG has concluded therefore that any costs arising through the NTS Environmental Incentive are not relevant to this methodology statement.

Part E: Determination of Incremental Compressor Maintenance Cost

87. Maintenance of NGG's compressor fleet consists of three elements:
    - Annual maintenance. This is undertaken irrespective of the loading (e.g. hours run) on the compressor.
    - Major overhaul. This is undertaken after 25000 hours of operation (equivalent to 2.9 years continuous running).
    - Breakdown, or emergency maintenance. This is undertaken as required.

88. Annual maintenance costs are incurred irrespective of the hours of operation and workload. Hence they are not included in this methodology.

89. Breakdown costs are intermittent and not readily assigned to a cause. Routine maintenance should limit the cost of breakdowns to a minimal level. Hence these costs are not included in this methodology.

90. On an annual basis, NGG will undertake network analysis to determine the incremental compressor running time. This will be carried out on a similar basis to that undertaken for determination of incremental CFU in paragraph 60. Analysis will consider different total system demand levels and, within that constraint, a range of flow rates at the reference node.

91. Based on the analysis in paragraph 90, NGG will assess the equivalent incremental compressor continuous running time, "T", e.g. without the pipeline two (T=2) additional compressors are required to be running throughout the demand range. It is unlikely that the same number of compressors will be required at all demand levels, hence NGG will, with due care and consideration of available relevant information, including forecast demands and reference node flow rates, assess the average requirement.

92. Due to the subjective nature of the assessment of T, the analysis to determine T, but no other aspect of this Part E may be challenged by the third party in accordance with paragraph 14.

93. An estimate of the cost of a major overhaul, "£M", will be determined for the first year of operation without the relevant pipeline. This shall be consistent with submissions for the applicable price control period. It shall be assumed, unless agreed otherwise, that this cost will rise in accordance with retail prices index. For year t, the cost M shall be determined as:

    $M_t = M_{t-1} * [1 + RPI_t / 100]$,

    where RPI_t means the percentage change (whether of a positive or a negative value) in the arithmetic average of the retail prices index published or determined with respect to each of the six months from July to December (both inclusive) in the year t-1 and the arithmetic average of the retail prices index numbers published or determined in respect to the same months in the year t-2.

94. The incremental compressor maintenance cost for year t shall be determined as:

    Cost (£/yr) = $T * M_t / 2.9$.

Annex 1

Example of Determination of Incremental Constraint Management Costs.

Consider a pipeline disposal where there is a relevant ASEP upstream of the pipeline at which there is a risk of increased constraints occurring.

At that ASEP, Shippers have firm entry capacity rights of 1.5 GWh/d

On Gas Day X, the Shippers nominate an end of day (EOD) quantity equal to a constant hourly flow rate of 1.4 GWh.

A constraint occurred at the ASEP at 00:00 such that a flow rate of only 0.7 GWh/d/24 could be accommodated.

Hence the maximum EOD quantity allowed was reduced to:

[1.5*18 + 0.7*6] / 24 = 1.3 GWh

To relieve the constraint NGG bought back 0.2 GWh/d of capacity (1.5 – 1.3) and capacity buy-backs were considered as follows:

Action	Time	GWh/d	p/kWh/d	Accepted
1	00:00	0.10	20	Yes
2	00:00	0.06	25	Yes
3	00:30	0.03	24	Yes
4	00:35	0.03	30	Part (0.01 GWh/d)

After Gas Day X, NGG undertook analysis to determine whether the constraint was due to the pipeline disposal.

This analysis showed that a flow rate of 0.9 GWh/d/24 could have been accommodated, had the pipeline not been sold, under the constraint conditions. This would have given an EOD quantity of:

[1.5*18 + 0.9*6] / 24 = 1.35 GWh.

Hence constraint management actions for 0.15 GWh/d (1.5 – 1.35) would have been needed.

Hence the incremental constraint quantity (ICQ(B)), attributable to the pipeline disposal, was

[0.2 – 0.15] = 0.05 GWh/d.

As the incremental constraint quantity is derived from the last actions taken, the relevant actions and costs are:

Action 4: 0.01 GWh/d at 30 p/kWh/d; plus
Action 3: 0.03 GWh/d at 24 p/kWh/d; plus
Action 2: 0.01 GWh/d at 25 p/kWh/d.

Hence, the cost attributable to third party is:

[0.01 * 30 + 0.03 * 24 + 0.01 * 25] * 10^6 / 100 = **£12,700**

Annex 2

Automated Approach to the Determination of Incremental CFU Quantity.

95. A network model shall be created based on the actual physical network at the time. This network shall replicate the entire NTS. It will not be limited to infrastructure adjacent to the removed pipeline. Although the process is intended to be automated, the model will need to be updated to reflect changes to the network, e.g. commissioning of new infrastructure, including new offtakes. These updates will be undertaken as soon as reasonably practicable.

96. The model will be populated with data taken from operational systems. Hence actual data experienced on the day shall be used. This also allows transient analysis to be undertaken consistent with the frequency of collection of site data. Data imported would include, but not be limited to; pressure and flow rates at entry and exit points to the network.

97. The model shall be run for each Gas Day and a CFU at relevant compressors identified. This will be the "CFUwithout", i.e. the CFU without the removed pipeline.

98. A second model shall be created, identical to the first except for the re-instating of the removed pipework. All data shall be replicated into the second model except that flows shall be balanced between the removed and remaining pipelines.

99. The second model shall be run for each Gas Day and a CFU at relevant compressors identified. This will be the "CFUwith", i.e. the CFU that would have occurred at relevant compressors with the pipeline in place.

100. The incremental compressor fuel usage for each Gas Day shall be the aggregate incremental CFU for each relevant compressor, determined from:

$$CFUactual - [CFUwith / CFUwithout] * CFUactual$$

Where CFUactual is the actual CFU for the compressor.

101. Although the simulation software currently used by NGG has functionality that enables automation of these types of networks significant development work will be required before it can be used. Hence until this development work has been completed the methodology described in the Part C shall be used to determine incremental CFU quantity.

Annex 3

Relevant System Constraint Locations and Duration.

In respect of the disposal of an NTS pipeline in Scotland between St Fergus and Avonbridge:

The following NTS system points shall apply for the determination of incremental costs in accordance with this methodology.

ASEPs – St Fergus

NTS Exit Points: All existing and new DN offtakes and System Exit Points, on all feeders, between and including St Fergus and Bathgate.

Relevant compressors are: Avonbridge, Kirriemuir, and Aberdeen[6].

The end date for payment of any incremental charges is 30th September 2020.

[6] Analysis is to be undertaken to confirm the materiality of incremental CFU at Moffat and Wooler relative to the stated compressor sites. If Moffat and Wooler are not of minor significance it is anticipated that they will be added to this annex.