

NGC Report on the First Tender Round for Obligatory and Enhanced Reactive Power Services

SUMMARY

Tenders were received in respect of 85 gensets. Assessment of tenders involved the application of all evaluation criteria specified in the Master Connection and Use Of System Agreement Schedule 5 ("MCUSA Schedule 5"). Forty one tenders have led to the signature of Market contracts with NGC for the period 1st April 1998 to 31st March 1999.

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INTRODUCTION

- i) Following work undertaken by the Reactive Power Market Working Group (RPMWG), a working group with pan-industry representation, new payment arrangements for reactive power procurement have been agreed. These provide a “safety net” or default payment arrangement for eligible generators, together with opportunities for potentially economic providers of reactive power services, to submit a tender for a reactive market contract (known as a “Market Agreement”). These arrangements are enshrined in a new Schedule 5 to the Master Connection and Use of System Agreement (MCUSA Schedule 5).
- ii) On 3rd December 1997 the National Grid Company plc (NGC) held the first reactive power market tender day. This enabled relevant Users (defined as a person using the NGC Transmission System) providing the minimum Grid Code Obligatory Reactive Power Service (ORPS), to offer alternative payment terms to the default payment arrangements over a contracted period, for the provision of voltage support to the NGC Transmission System in the contracting period commencing 1st April 1998. This alternative market arrangement also permits Users the opportunity to tender reactive power capability in excess of that required by the Grid Code obligations - a so-called “Grid Code Plus Enhanced Reactive Power Service”. Furthermore an Enhanced Reactive Power Service (ERPS) can be offered by any other eligible service provider, who does not provide an ORPS.
- iii) This report describes the tenders received and the subsequent selection process that led to Reactive Market contracts being struck from 1st April 1998. These tenders related to ORPS services, required under the Grid Code, and also, in a number of instances, to ERPS services.
- iv) This tender round is the first to take place, and will be repeated on a six-monthly basis. In order to explain the arrangements, a seminar was held at the Raven Hotel, Droitwich on 27th September 1997. The closing date for tenders was 4th December 1997. The next reactive market tender day by which tenders should be submitted (the “Market Day”) is 10th June 1998 for contracts commencing 1st October 1998. Invitation To Tender packs are available for any eligible provider to submit a tender.

VOLTAGE REQUIREMENTS

- v) NGC manages the voltage of the supergrid system, to meet Transmission Licence requirements for secure and stable power transmission and to ensure quality of supply to customers. Voltages are largely determined by the flows of reactive power on the system. NGC ensures:
 - a) that reactive power resources are provided on a local basis to meet the constantly varying needs of the system, and
 - b) that there is sufficient reactive power reserve made available to meet contingencies.

(An introduction to the basis of the need for reactive power to support voltages on the transmission system is given in NGC’s Seven Year Statement, Appendix C.6.)

- vi) Generating units provide reactive power capability, and the ability to vary their reactive power

output, as a requirement of the Grid Code. The power system itself has inherent reactive gains and losses, which vary in accordance with changes in the power flows and voltage. NGC installs reactive compensation plant in parts of the system where there is insufficient generator reactive capability to meet requirements and voltages cannot be regulated effectively or economically by other means. NGC may also contract for generator reactive power capability in excess of that required by the Grid Code, or for other services where economically viable, to help manage the voltage characteristics of the NGC transmission network.

1. Nature of Tenders Received

- 1.1 Tenders were received from 85 gensets at 36 stations; this represents approximately one half of the total of 154 centrally despatched gensets, but accounts for approximately 70% of last years total genset Mvarh output. 13 generating companies tendered and nuclear, gas, coal, oil and hydro fuel-types were all represented.
- 1.2 All tenders were in respect of centrally despatched gensets, and none were from non centrally despatched sources. In addition, all tenders were for the minimum period of 12 months 1st April 1998 to 31st March 1999.
- 1.3 All tenders ultimately met the stringent rules for data consistency and alignment with Grid Code provisions, as set out in MCUSA Schedule 5. Appendix 6 of MCUSA Schedule 5 details the qualification and evaluation criteria. The Grid Code defines technical performance at genset LV terminals at rated MW. This must be translated for market purposes into the equivalent capability at the HV commercial boundary at Genset Registered Capacity. The process of data exchange and checking between NGC and prospective tenderers in the weeks leading up to the Market Day delivered increased confidence in reactive data quality of current Grid Code submissions. With the basic technical and commercial data updated for the commencement of the market, the tender compliance process is expected to be more straightforward in subsequent tender rounds.
- 1.4 9 tenders at 3 stations were for Grid Code plus Enhanced Reactive Power Services, offering an increase on Grid Code capability of just under 200Mvar in total (leading plus lagging).
- 1.5 Most tenders had identical or similar tender data for all gensets at a station; this simplified the assessment process. In a few cases, perhaps to assess the sensitivity of the market, different prices were submitted for gensets at the same station.
- 1.6 About half of the tenders, in NGC's broad assessment, appear to be seeking a similar split of reactive payment monies between Utilisation and Capability, as provided by the default payment arrangements for 1998/9 under which reactive payment monies overall are split 50:50 Utilisation:Capability for year 1998/9. Of the remaining tenders, the majority appear to be seeking greater remuneration of their reactive power capability.
- 1.7 Under the default payment arrangements, shortfalls of reactive power capability are subject to payment reductions made on a quadratic basis. Most tenders opted for a simpler structure of reactive power capability payments, reflecting a more linear payment rate per Mvar of reactive power available. A few tenders included a more 'kinked' structure of payment, under which the genset loses a greater proportion of money for a small shortfall in reactive power capability.
- 1.8 The majority of tenders included capability prices for hours available only; however some tenderers wished to be paid capability money in part on hours synchronised also. Whilst increasing uncertainty and complexity in structuring and evaluating tenders, this aligns reactive power capability payments with the hours when a genset can deliver a useful reactive power service to the system.

2. Assessment Process

- 2.1 NGC divided the process of assessing the reactive power tenders into several stages, which were addressed as follows.
- 2.2 (i) *Tender Receipt and Registration*: the tenders were opened, in the presence of a separate witness, and all tender data was transcribed onto a pre-formatted tender database.
- 2.3 (ii) *Tender Data validation*: the database entries were then separately checked back to the original tender sheets. Prepared software checks raised a number of minor data queries that were all resolved. As noted in section 1, these stages proved time consuming but essential to achieving a set of compliant tenders for commercial evaluation.
- 2.4 (iii) *Obligatory Reactive Power Service Assessment* the tenders were assessed against likely outgoings, taking into account the many interacting factors associated with each tender acceptance decision, as described in MCUSA Schedule 5, Appendix 6. This involved, amongst other factors, evaluation against projections of expenditure and availability of service against historic and forecast Mvar and Mvarh data, to produce central views of the monies payable under the default payment arrangement or under a Market Agreement for 1998/9. Details of this particular element of processing are described in section 3. below. The overall assessment was supported by a number of post processing spreadsheet calculations examining credible sensitivities around the core analytical assessment view. These are described in section 4. below.
- 2.5 (iv) *Enhanced Reactive Power Service Assessment*: tenders for ERPS services required additional assessment of their value against possible alternatives, mainly of NGC constraints and investment. This was done on a case-by-case basis for the three stations concerned. Tenders for ERPS are considered to be a valuable component of the reactive market process in that they inform NGC's overall planning process.

3. Core Analytical Processing

- 3.1 Tender assessment takes place in the context of uncertainties and interactions of factors affecting reactive uplift payments and transmission requirements. To initiate the assessment of the overall value of each tender, it is considered necessary to construct a central view of future payments so that the relative impact of the factors influencing the economic evaluation of tenders can be fully addressed.
- 3.2. For each genset tendered for 1998/9, the processing was as follows:
- 3a. Firstly NGC produced a central view of the default Zonal Weighting Factor ('ZWF') tariff for 1998/9. This was a subjective update of that shown in the April 97 Seven Year Statement, and thus was likely to be no better than any other party's estimates of ZWFs. In the subsequent overall analysis these were placed with significant uncertainty (in the order of at least ± 0.5 £/kvar/year) on each default ZWF. This uncertainty will be less significant next year, when the staircase ramps down to a 25% weighting on capability monies.
 - 3b. The default capability money was then set at Grid Code capability times ZWF.
 - 3c. Forecast Mvarh generated, in each band by reactive Mvar breakpoints, were set via extrapolations from historic observations and forecast load factors. The historic observations covered representative days over 1996 and 1997, and came from the Ancillary Services records against which reactive power utilisation is currently being paid.
 - 3d. The default utilisation money was set at forecast Mvarh multiplied by assumed final utilisation price of 0.62 £/Mvarh nationally.
 - 3e. Market Agreement capability monies were set at tendered price multiplied by tendered capability, allowing for break-points, multiplied by forecast hours both available and synchronised.
 - 3f. Market Agreement utilisation monies were set at tendered prices, multiplied by the same forecast Mvarh as in 3c, respecting the tendered break-point bands of Mvarh utilisation.
 - 3g. The core comparison of default versus Market Agreement payment purely sums 3b + 3d versus 3e + 3f. Reactive power assessment is however, by no means as simple as taking the cheapest apparent option. As will be seen in the following section, a full understanding of the factors influencing reactive power requirements on the NGC Transmission System must be taken into account to provide a complete economic assessment of tender value.

4. Tender Assessment

4.1 The principal role of the final overall tender assessment, was to quantify and evaluate consistently the many factors that NGC and the RPMWG had agreed should be included in the assessment of all tenders. These factors are those referred to in 5.3(e)(ii) of MCUSA Schedule 5 and were cross-referred in section 2.12 of the Invitation to Tender pack. A NGC evaluation team developed and implemented a process enabling these factors and associated uncertainties to be methodically considered.

4.2 The RPMWG had accepted, at the outset, that aspects of the evaluation process would be subjective in nature. It was thus important to establish a framework within which this subjectivity could be exercised in a consistent fashion across all tenders.

4.3 The NGC evaluation team developed and implemented such a framework, enabling these factors and associated uncertainties to be methodically considered against the background of NGC's Licence and statutory requirements for economic purchase and economic, efficient operation and the intentions of the RPMWG for the development of the market. Specific questions were asked of each tender of the nature:

- would a Market Agreement (central case assessment) give a reduction in payments?

- would a Market Agreement be robust against:

** the envelope of credible outturn ZWF's*

** expected individual variations in the utilisation due to:*

** a new station opening nearby*

** an existing nearby station closing*

** trends in local reactive power demand*

- would a Market Agreement enhance the incentive on the Generator to maintain his Grid Code capability?

- how would a Market Agreement affect operational despatch?

- to what extent might a Market Agreement potentially offset NGC investment?

- would a Market Agreement for ORPS enable a desired contract for ERPS?

4.4 All other criteria in MCUSA 5 para 5.3 are covered by this methodology.

4.5 To illustrate the nature of the issues involved in reactive power assessment, the following paragraphs highlight some of the most marginal contract / non-contract decisions.

4.6 All the marginal cases had tendered prices in respect of which NGC perceived no significant difference in forecast reactive power payments under the default payment arrangements or under Market Agreements, after consideration of the uncertainties. The judgment applied to this basic economic assessment is such that, if the forecast payment under the Market Agreement

differs from that under the default payment arrangement by more than say $\pm 25\%$, and this difference is broadly robust to our range of views on outturn utilisation and ZWF, then the contracting decision will not be marginal.

- 4.7 A number of these marginal cases are swung by consideration of the incentive on the generator to maintain reactive power capability. Under the default payment arrangement, a shortfall in reactive power capability of say 5% results in a reduction in capability payments on a quadratic basis, thus by 10%. A number of the marginal tenders had priced a single (linear) price for reactive power capability available, and thus in the above example would only see a 5% reduction in capability payments. NGC perceives there to be value in the reactive power market in the provision of capability, and thus the incentive to maintain it; so in a number of the marginal cases, this consideration had the potential to influence the decision whether to accept or reject a Market Agreement. In cases where capability considerations are material, a genset's previous record of reactive shortfalls can also be a factor contributing towards rejection.
- 4.8 Most of the marginal cases had tendered a utilisation price close to the default payment arrangement of 0.62 £/Mvarh, and thus considerations of possible savings from "swinging" the despatch of Mvarh did not arise. In one marginal case, there were different Mvarh prices between gensets at the same station; in the extreme this could lead to despatch difficulties, and NGC viewed this type of tender adversely.
- 4.9 In all cases, NGC considered interaction with forecast constraints. In a few instances across the whole assessment, the nature of the outage programme in the vicinity of the tender led us to a view that the despatched Mvarh would be affected by the outages; but no significant interaction with constraints was identified.
- 4.10 In all cases, NGC considered possible interaction with NGC planned investments. Commissioning in 1998 of new NGC transmission equipment, which includes some reactive compensation equipment, influenced our view of forecast Mvarh. This equipment is all being installed for compliance with Transmission Licence Standards. In none of the cases for ORPS assessments were there any counter-interactions, namely that a Market Agreement would offset or delay planned investment. This is mainly because all tenders received were for the minimum period of 12 months and NGC has not yet planned any investments on the grounds of reduced Mvarh generation.

5. Assessment Results

- 5.1 In respect of the 85 assessed tenders, the range of assessment outcome is shown in a histogram in Figure 1. The distribution is two-peaked, where those gensets in the left-hand peak are clear-cut rejection decisions, and those in the right-hand peak are clear-cut acceptances. The 8 gensets in the central bar are generally influenced by the factors described in detail in paras 4.8 to 4.12 above.
- 5.2 Overall, 41 tenders led to a Market Agreement being signed. These represent gensets from 18 stations owned by 7 different generating companies. Signed Market Agreements represent some 30% of the total genset Mvarh despatched and approximately 30% of the overall lagging capability available.
- 5.3 Given the differences between zones, and also between genset utilisations and market bid structures within each zone, NGC has not sought to construct any meaningful summaries of this successful tender data across gensets.
- 5.4 On this occasion, none of the tenders for a Grid Code Plus Enhanced Service were accepted. Savings against forecast constraints were modest, and tenders were more expensive than advancement of putative NGC compensation. In two of the cases, the underlying ORPS Market Agreement was also unattractive.
- 5.5 The total reactive cost for 1998/9, allowing for the above mix of Market Agreements and default payment arrangements, is *forecast* to be lower than that for a background of all generators being paid under the default payment arrangements. Of course, the final reactive cost remains dependent on outturn MWh load-factors, Mvarh generated, capability performance, outturn ZWFs, and also the outturn of the first six months of the second reactive power market tender round for market Agreements to start on 1st October 1998.

6. Concluding Observations

- 6.1 Any reduction inferred from total forecast cost may reflect a success, for electricity consumers, of the reactive power market process. However, NGC views any reduction as a possible 'one-off', and believes that it will take a number of years for a reactive power market process to settle down. A number of generators may bid more aggressively in future rounds, and in any event the forecast remains uncertain.
- 6.2 Overall, the assessment recognised that the interchange of despatched Mvarh between sources by NGC will be limited in the short term. There are a number of reasons: one being the number of stations tendering with the majority of utilisation close to the default of 0.62 £/Mvarh; NGC software capable of auto-despatch is two years away from implementation, and manual investigation of possibilities is a resource intensive exercise in terms of control room workloads and priorities.
- 6.3 Over the immediate years 1999/00 and 2000/01, the default payment arrangement will move to a ratio of 100:0 on payments in respect of Utilisation:Capability, subject to review. NGC perceives value within the reactive market in reactive capability, and will welcome tenders in future rounds which are structured to lower utilisation (£/Mvarh) prices, in return for some capability money. We believe that such tenders will offer greater certainty for both NGC and prospective tenderers in the reactive market.
- 6.4 NGC considered the interaction of all tenders with NGC planned and putative investments. Offers for ORPS were for one year and as such did not interact with any putative investments. Current planned investments, as described within NGC's Seven Year Statement, are all for compliance with Transmission Licence security requirements. ERPS were not assessed as economic in this instance. One factor in this assessment of ERPS tendered was the absence of available savings against deferment or offsetting of putative investment.
- 6.5 The next reactive power Market Day will be 10th June 1998, and tenders on that day will be for a minimum of 12 months from 1st October 1998 to 30th September 1999. This period not only crosses two financial years, but is also subject to two differing staircase effects. Gensets with Market Agreements in place from 1st April 1998 will not be eligible to participate until the third contract round for the period 1st April 1999 to 31st March 2000 at the earliest.
- 6.6 The first tender round has seen an encouraging number of participants seeking remuneration through Market Agreements. The wide geographic, owner and fuel-type spread is also viewed as beneficial to the overall evolution of this newly established market.

Figure 1



