Paper to Pool Members by British Gas Trading

Anomalous Pool Prices during 2000
Problems and Remedies

24th October 2000

Executive Summary

Over the past two years Pool prices have moved so far away from economic fundamentals that they have become meaningless. There is now no longer any sensible correlation between price and demand.

The purpose of this paper is to analyse reasons for the departure of pool prices from economic fundamentals and propose remedies, pending the implementation of NETA.

The proposed solutions to the problems described in this paper focus on:

i) Amending the treatment of demand reduction blocks in the LOLP calculation.

ii) Modifying the use of disappearance ratios such that fixed values are used for most plant. The values are derived from a consideration of the level of reserve scheduled by NGC.

iii) Reviewing the operation of GOAL to determine the reasons for the occurrence of SMP price spikes that have become a feature of Pool prices, with a view to their subsequent removal.

Pool members are requested to agree that:

Resolution 1
Demand reduction blocks should continue to receive their payments but that the amount of demand reduction for which they are paid should be incorporated within the LOLP calculation, either as an increase in generation capacity or a reduction in forecast demand or reserve, which ever is easier to implement.

Resolution 2
Disappearance ratios used in the calculation of LOLP be changed to correspond more closely with the level of NGC reserve, as described in this paper, as follows:

Newly commissioned plant (i.e. within 12 months of settlement commissioning) – live monthly ratios as currently calculated;

	Winter	*Summer*
All other plant (including Range)	***0.04***	***0.05***
Interconnectors (French & Scottish)	***0.04***	***0.05***

Winter being October to March inclusive, and Summer being April to September inclusive.

Resolutions 3a-d

a) NGC be asked to examine the way in which GOAL is scheduling generation units and produce a report for Pool Members on the causes of the high SMP values that have been occurring over this summer, as described in this paper.

b) NGC be asked to report if there is any flexibility in the GOAL scheduling program that could be used to reduce the occurrence of these SMP spikes.

c) That the terms of reference of the Market Monitoring Group (MMG) be expanded so that they investigate and report on all unusual price features within the Pool, irrespective of whether they are compliant with the Pool Rules.

d) That Non Pool members who are active traders in the forward electricity market should also be invited to attend the MMG.

1 Introduction

1.1 Over the past two years Pool prices have moved so far away from economic fundamentals that they have become meaningless. There is now no longer any sensible correlation between price and demand. Prices for the past two summers have been higher than the preceding winters. Whilst this may make sense in California, it certainly should not in England and Wales.

1.2 At a time when NGC is stating in its Seven Year Statement (SYS) that there is a plant margin for 2000/01 of 25.3% with registered generation plant capacity of 66GW, we have had a summer characterised by an apparently high risk of failure to meet demand, at least to judge by the very high level of capacity payments being made. One interpretation of these prices would be that the Pool is sending strong price signals to encourage new plant to be built, rather than reflecting the actual over capacity.

1.3 In concert with the high capacity payments, this summer has also been typified by System Marginal Price (SMP) spikes in the region of £40 to 50/MWh. These spikes seem to be caused by GOAL scheduling relatively small increments of "expensive" generation to meet minor increases in the forecast demand. Often, these spikes occur away from the demand peak of the day.

Table 1: Pool Price statistics for previous 12 months

MONTH	Average SMP £/MWh	Average LOLP payment £/MWh	Average PPP £/MWh
Oct-99	20.23	0.90	21.13
Nov-99	20.56	2.32	22.87
Dec-99	21.74	2.22	23.97
Jan-00	24.39	6.57	30.96
Feb-00	22.38	0.99	23.37
Mar-00	17.35	0.39	17.74
Apr-00	17.81	7.87	25.68
May-00	19.58	4.37	23.94
Jun-00	17.06	3.19	20.25
Jul-00	17.90	0.92	18.83
Aug-00	17.99	5.84	23.83
Sep-00	19.75	20.27	40.03

1.4 Thus judged by any sensible measure that relates demand, supply and cost, recent pool prices bear no relationship to economic fundamentals. This is detrimental in the near term for customers on Pool related contracts, suppliers to the extent that sales are unhedged and for traders who have tried to trade on the basis of reasonable expectations of market behaviour. In the medium term it is detrimental for all customers as one clear consequence of the high Pool prices has been to raise prices in the forward market. This in turn feeds through into the annual contracting round and results in higher contract prices for all customers and suppliers. The magnitude of this distortion can be measured by comparing the average Pool price for the last twelve months of £24.36/MWh with the price for annual base load contracts from April 2001 in the forward market of £20/MWh. This clearly illustrates that participants envisage NETA to be more competitive than the Pool once it is introduced early next year.

1.5 The purpose of this paper is to analyse reasons for the departure of Pool prices from economic fundamentals and propose interim remedies, pending the implementation of NETA.

2 Capacity Payments – Analysis

2.1 The distortion in capacity payments (also known as LOLP payments) has been so extreme that September 2000 has managed to record the highest monthly average by far over the last year (see Table 1). September 2000 was only £2/MWh away for the highest monthly average ever in winter 1994/95. Total capacity payments through the Pool in September alone were over £500 million. This is double the very high value seen in September last year and some one hundred times higher than the September figures for 1997 and 1998.

2.2 Not only do high capacity payments distort Pool Purchase Price but they also increase Uplift via unscheduled availability payments. This is a cost borne by all suppliers and is essentially un-hedgable. Since January 2000, the total cost of this element of uplift has been £348 million with September alone reaching £139 million as shown in Table 2.

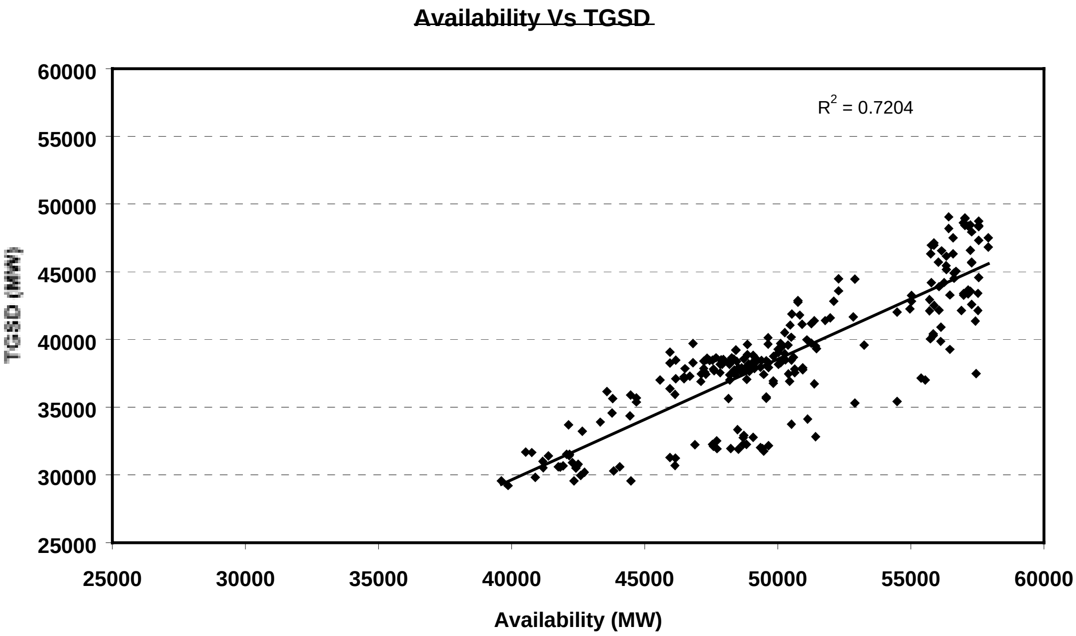
Table 2: Unscheduled Availability Costs (2000)

Month 2000	TWA £/MWh	National Costs(£)
January	1.214	43,112,443
February	0.228	7,333,259
March	0.106	3,462,177
April	1.627	48,093,867
May	0.905	25,716,895
June	0.817	22,346,617
July	0.235	6,568,320
August	1.495	41,290,453
September	5.032	139,867,714
October (part)	1.174	10,395,823
Ytd(9 Oct)	1.287	348,187,568

2.3 These high capacity prices are directly related to the absence of significant amounts of generation capacity this summer. Plant has been absent for a mixture of planned and unplanned outages. Some generation capacity was withdrawn for “economic reasons” and has been investigated by OFGEM under the “good behaviour clause” added to some generators’ licences. The impact of this plant shortage has been magnified out of all proportion by the disappearance ratio mechanism that is part of the mechanics in the Pool rules for computing capacity prices.

2.4 Chart 1 clearly shows a strong correlation between available generation and demand. This is not intuitively logical.

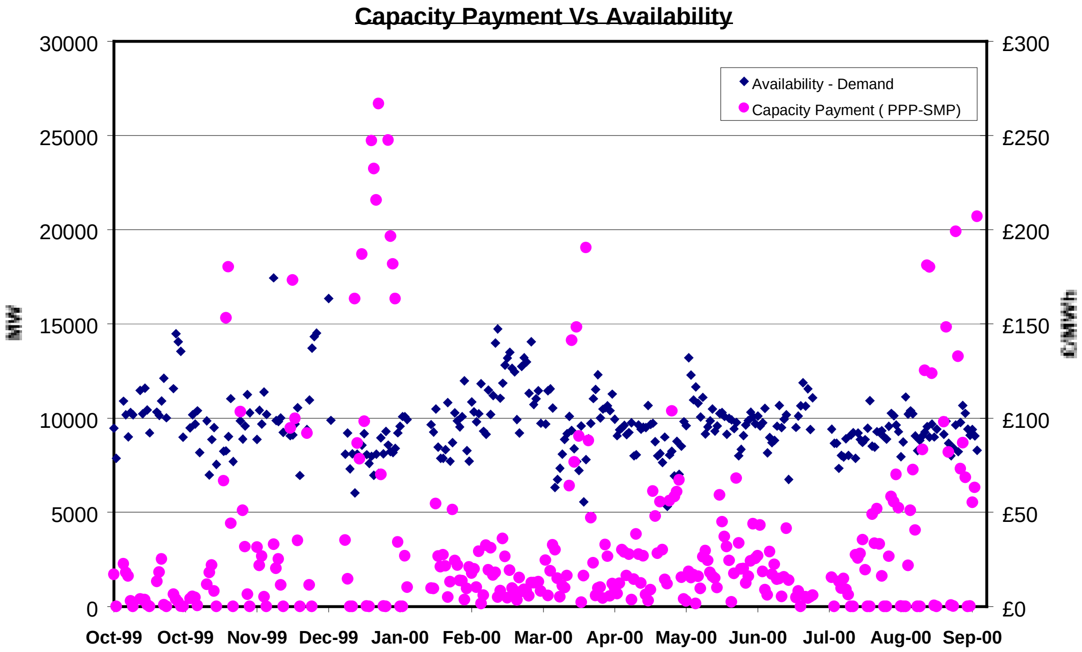
Chart 1



2.5 The following Chart 2 shows the relationship between capacity payments and the difference in availability and demand, at the daily demand peak, over the last twelve months.

2.6 It is clear that, for whatever reason, the margin between demand and available generation was usually at a level between 8,000MW and 11,000MW over the whole period that led to capacity payments persisting through the whole summer period. Generally it appears that the capacity payment mechanism gets triggered too early and responds too quickly when there is no real shortfall in capacity.

Chart 2



3 Capacity Payments – Calculation Defects

3.1 The LOLP calculation, in simple terms, compares forecast demand with available generation, and from this computes a probability of lost load to apply to the Value Of Lost Load, to give a capacity payment for each half hour.

3.2 The input data which go into this calculation are:

- Forecast availability
- Forecast demand
- Disappearance ratios
- Value of Lost Load
- Others such as: Seasonal Error Allowance.

3.3 There are many aspects of this calculation that could be challenged on the basis that they are adrift from economic fundamentals. They include the following:

(a) the LOLP calculation looks only at the absolute difference between generation and demand, not the relative difference. Thus a generation margin of 5000MW would create the same price signal at time of summer troughs as winter peak, although the absolute level of demand might be different by 250%.

(b) the capacity elements of pool prices has a logarithmic component which means that it increases by a factor of 10 for approximately each 2000MW of capacity reduction.

(c) Demand reduction blocks offered by certain large consumers are included as “pseudo-generation” for the purposes of Pool Payments and hence receive Capacity Payments. This increases the unscheduled availability cost for suppliers. However, for no apparent reason, this demand reduction is not included within the LOLP calculation, either as a reduction in demand or as additional “generation”. This is clearly anomalous.

(d) Disappearance ratios (DRs) are applied as an adjustment to genset unit availability to allow for the fact that generation units carry a risk that they will not actually be able to run when scheduled to do so by the Grid Operator. In order to avoid genset unit offered availability for one day affecting the following day’s capacity calculation, the highest offered availability of each genset over the previous seven days (XMAX_0) is used. A daily DR is calculated as the sum of the variances between actual availability (XP) and XMAX_0. Monthly and seasonal DRs are derived from daily values.

When examined in detail, it is clear that this calculation systematically underestimates the amount of capacity actually available and despatched at peak times. This occurs either if the XP values have varied within the day due to the plant availability being profiled by the generator or because of the effect of partial planned or unplanned outages.

The partial outage effect occurs if part but not all of a genset or CCGT module is unavailable for a period. If the whole unit is unavailable then no DR is calculated. However, a DR value not representative of actual availability will be calculated for the first seven days of each partial outage period because the comparison is with XMAX_0. Most CCGT modules in the UK have multiple gas turbines for which it is common practice to schedule planned maintenance of one gas turbine at a time; causing the above distortion. As newly built units build up a history of performance, historic seasonal effects are incorporated into the DRs applied each month. This can lead to little correlation between recent performance and the actual “performance risk” factor applied via the DR.

Actual monthly DRs thus vary very significantly between different units. Most values appear to range from 5% to 20%, depending upon plant and season. This translates into anywhere from 4,000 to 10,000MW of capacity being excluded from the LOLP calculation, more so in the summer when maintenance effects are higher. The fixed seasonal DRs for pre-vesting plant are also sculpted by season.

In effect, the calculation uses average availability which ignores the fact that some plant are fully available at peak times but less available off-peak.

An alternative way of approaching this question of plant reliability is to look at the levels of reserve which NGC schedules each season for system support reasons. Table 3 shows some recent seasonal values.

Table 3: Analysis of reserve levels for winter and summer; compared to typical demand and generation availability.

	Low reserve (MW)	High reserve (MW)	Typical Peak Demand (MW)	%	Gen. Avail. (MW)	%
Winter weekday	750	1350	40,000	3.4	50,000	2.7
Summer weekday	1450	1500	32,000	4.7	42,000	3.6

Source: Pool circular 350, 418, 439

This data would indicate that NGC view the level of reserve necessary to cover the risk of short-notice plant failures, transmission faults etc to be some 1,500MW or 3.5 to 5% of typical peak demand or 3 to 4% of typical available generation capacity.

Conceptually, there would seem to be a significant congruence in the underlying concepts of disappearance ratios and reserve. However, if one looks at the effect of DRs, the magnitude is much greater with typically over 10% of generation plant being excluded from the capacity calculation. This would seem to greatly exaggerate the risk of day-ahead plant failure and hence artificially increase the level of capacity payments. As has been discussed it is also likely to be distorted by profiling of plant availability.

Using the NGC reserve figure as a benchmark for the impact of DRs, would “add back” at least 3,000MWs of excluded generation capacity which would reduce the capacity payment by a factor of at least 10.

Taking a conservative view by using the highest weekday level of reserve and comparing this to the typical peak demand (from NGC SYS), which must understate the amount of generation, would give a winter reduction factor of 4% and a summer factor of 5%.

4 Capacity Payments – Remedies

4.1 Whilst the rigorous approach would be to rewrite the detailed algebra of the LOLP calculation, this would not be time nor cost effective at this stage in the life of the Pool. Thus a pragmatic but fair solution must be looked for.

4.2 It is proposed that demand reduction blocks should continue to receive their payments but that the amount of demand reduction for which they are paid should be incorporated within the LOLP calculation, either as an increase in generation capacity or a reduction in forecast demand or reserve, which ever is easier to implement.

4.3 It is proposed that Disappearance Ratios used in the calculation of LOLP be changed to correspond more closely with the level of NGC reserve, as follows:

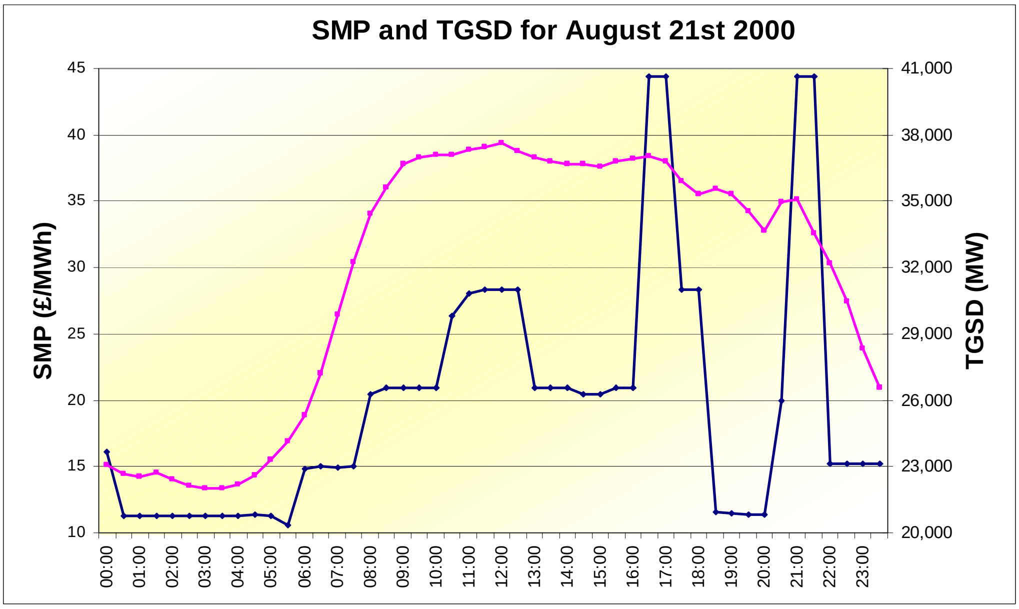
Newly commissioned plant (i.e. within 12 months of settlement commissioning) – live monthly disappearance ratios as currently calculated;

	Winter	Summer
All other plant (including Range plant)	0.04	0.05
Interconnectors (French & Scottish)	0.04	0.05

5 SMP Spikes – Analysis

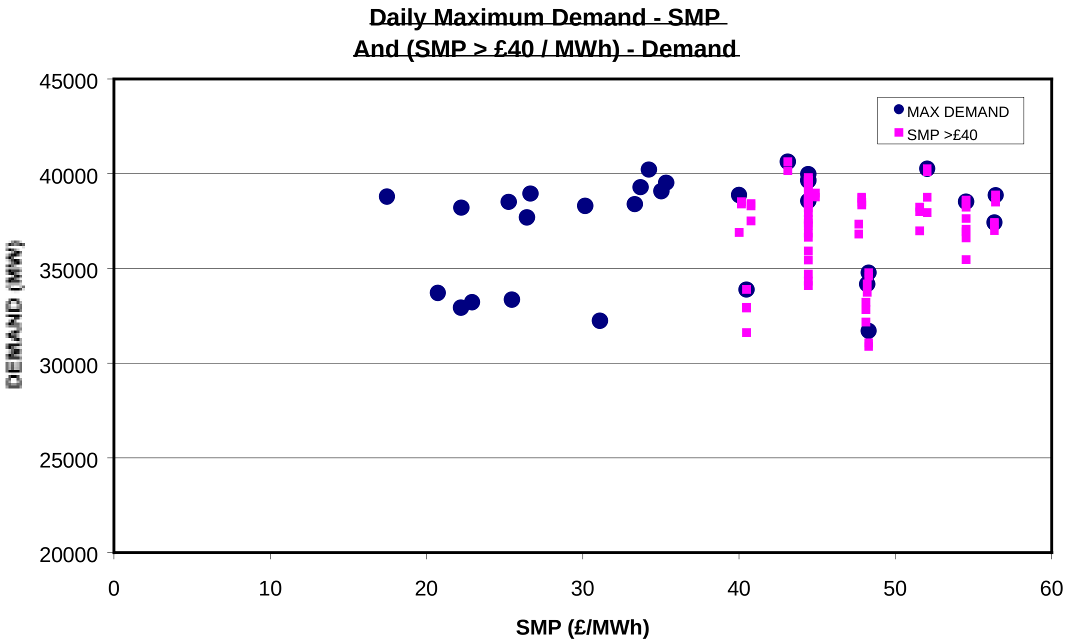
5.1 In parallel with the unusual capacity prices this year, there have been many occasions when the value of SMP has "spiked" up in a manner that again does not correspond with supply/demand fundamentals. For example, over the last few months there have been one or two occasions almost every day where SMP has jumped to a level of £44.44/MWh for two consecutive settlement periods at times of minor demand increases and otherwise lower SMPs. Chart 4 shows one such day. It is clearly counter-intuitive that the highest SMP does not systematically occur at the time of highest demand.

Chart 4: An example of an SMP spike



5.2 Chart 5 illustrates the lack of correlation between peak demand and high SMP values for September 2000. For each day, the highest demand and SMP pair has been plotted as the first data set. Then all SMP values over £40/MWh, with the corresponding demand value, were plotted as a second data set. This clearly shows that on about half the days, the period of highest daily demand did not coincide with the highest SMP value.

Chart 5



5.3 The scheduling software (GOAL) appears to be selecting expensive marginal generation to meet minor increases in the forecast of demand. OFGEM has previously investigated and commented on SMP spikes caused by high second and third incremental offer prices submitted by generators. This led to Pool Members making some modifications to the Pool Rules to exclude units with very high incremental prices being scheduled at the margin and then setting unrealistic SMPs. The current SMP spikes appear to be a similar problem but presumably arising from a different structure of bid associated with flexible plant.

5.4 Moreover, the resultant SMP value calculated often seems to be higher than the offered full load price of the marginal genset. This would seem to indicate that the cost attribution rules are working in an unexpected way.

6 SMP Spikes –Discussion

6.1 Getting to the bottom of cause and effect within GOAL and the subsequent calculation of SMPs is extremely difficult for most Pool Members. Whilst the Pool did set up the Market Monitoring Group after the last episode of unusual prices, this committee seems to have too narrow a remit to investigate, on its own initiative, price anomalies as described above.

6.2 The defects of the mechanistic scheduling approach to setting prices have been much debated and the absence of this type of mechanism from NETA would seem to indicate that it is not considered appropriate in the more market based approach sought via NETA. Thus, during the remaining life of the Pool the challenge is to see if there are ways of keeping the occurrence of abnormal SMPs under control.

6.3 It is detrimental to Supplier Pool members if GOAL, whilst seeking to minimise its objective of “lowest production cost”, is setting artificially high SMP values because of the content or structure of some of the generator offer data. This is particularly true when the error inherent in NGC’s forecast of demand is considered. Based on an examination of recent TGSD forecast and actual data, it would appear that the error at times of high demand is often 500MW and can some times reach 1000MW. The forecasts for periods of low demand appear fairly accurate, as do the periods of rapid change. Given the size of the forecasting uncertainty it appears unreasonable that suppliers should bear the costs of high SMPs caused purely by GOAL scheduling expensive flexible generation to fill apparent shortfalls in the schedule of less than the forecasting error.

6.4 The resulting SMP spikes not only raise the cost to customers on Pool contracts but increase the overall level of SMP which feeds through into the forward market raising the cost of forward contracts and hedges. In addition, the random nature of their occurrence across the day increases the uncertainty around the pricing of non-baseload contracts thus reducing the liquidity of such contracts and potentially artificially increasing their prices.

7 SMP Spike Proposals

7.1 Clearly, it is reasonable to expect SMP values to increase at times of higher demand so it is necessary to distinguish between an “abnormal” SMP rise and an acceptable one. One practical test that seems to work fairly well is to look at settlement period SMP values that are more than 50% above the daily average as being potential spikes.

7.2 As a first step towards addressing the current SMP spikes, it is proposed that Pool Members ask NGC to produce an analysis of the causes of the current spikes with particular emphasis on the flexibility and prices offered by generating units. NGC should further be asked whether there is any flexibility in GOAL that could be used to reduce the occurrence of these spikes.

7.3 It is proposed that the terms of reference of the Market Monitoring Group (MMG) be expanded so that they investigate and report on all unusual price features within the Pool whether identified by the Group or by other Pool Members, irrespective of whether they are compliant with the Pool Rules.

7.4 It is further proposed that Non Pool members who are active traders in the forward electricity market should also be invited to attend the MMG.

8 Implementation

It is recognised that the implementation of the various changes discussed in this paper will incur costs and may take some weeks to implement. However, these changes are recommended to Pool members as necessary to improve the credibility of the relationship of the Pool prices to economic fundamentals.

9 Summary of Resolutions put to Pool Members:

<u>Resolution 1</u>

Demand reduction blocks should continue to receive their payments but that the amount of demand reduction for which they are paid should be incorporated within the LOLP calculation, either as an increase in generation capacity or a reduction in forecast demand or reserve, which ever is easier to implement.

<u>Resolution 2</u>

Disappearance ratios used in the calculation of LOLP be changed to correspond more closely with the level of NGC reserve, as described in this paper, as follows:

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