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INTRODUCTION

Many of the power purchase agreements between the former Ontario Hydro and Non-Utility Generators (NUGs) utilized indices pursuant to which the contract price was intended to be adjusted on an annual basis. Representatives of Ontario Electricity Financial Corporation (OEFC) and the Independent Power Producers Society of Ontario (IPPSO) have undertaken discussions to identify potentially suitable replacements for those indices that have ceased to exist as a result of the restructuring of the electricity sector. Statements in this draft report regarding OEFC and IPPSO agreeing to or proposing a matter or of similar effect are to be interpreted as being the agreement or the proposal of the working committee of the OEFC representatives and IPPSO representatives only.

The discussions between OEFC and IPPSO have mainly focussed on determining an appropriate replacement for the former Ontario Hydro's Direct Customer Rate (DCR). The replacement for the DCR will not replace the rates which OEFC will pay for electricity but rather will replace the DCR in its role as an index used in calculation of changes to such rates. It is proposed that the DCR and those indices, which have historically been comparable to the DCR (i.e. Average Customer Rate), be replaced with a single index for consistency, fairness and ease of administration.

Both OEFC and IPPSO have approached these discussions on the basis that the replacement for the DCR should replicate, to the extent possible, the nature and behaviour of the DCR as it currently exists. Furthermore, any such replacement should not afford any benefits or cause any detriments to either OEFC or each NUG contract holder that did not exist within the original DCR.

IPPSO has established a NUG Contracts Committee to provide a forum for IPPSO members to discuss issues related to their NUG contracts and to act as a clearinghouse for ideas and an information exchange among affected IPPSO members and with OEFC. It is acknowledged by OEFC that IPPSO representatives from the NUG Contracts Committee have undertaken discussions with OEFC on the basis that IPPSO has no ability to bind its members and does not in any way intend to limit, affect or prejudice the negotiations which individual NUG contract holders may have with OEFC. For purposes of this report, IPPSO has not had access to the NUG contracts and IPPSO has not reviewed any particular NUG contract. Each NUG will have to assess the implications of this report to the specifics of its contract(s).

It is acknowledged by IPPSO that the recommendations made by OEFC representatives in this report are subject to the approval of the OEFC Board.

BACKGROUND

NUG Advisory Committee

The NUG Advisory Committee was established by the Ministry of Finance to advise on the management and disposition of the power purchase agreements (PPAs) entered into by the former Ontario Hydro with each NUG. The Committee, which was comprised of government representatives, as well as various industry and financial experts, completed its work and issued a report on October 14, 1999.

In its report, the NUG Advisory Committee recognized the need to revise the NUG contracts as a result of the restructuring of the electricity industry. One of the principal reasons which makes revising the NUG contracts necessary, is the fact that the contracts presently contain any one or more of a number of indices pursuant to which the contract price is adjusted on an annual basis. A number of these indices have ceased or will cease to exist as a result of the restructuring of the electricity industry.

It was not the intention of the NUG Advisory Committee to embark upon the process of negotiation as to the acceptability of any given option but to identify, to the extent possible, potentially suitable replacement indices with a view to facilitating future negotiations between the relevant parties.

The NUG Advisory Committee was of the view that the appropriateness of any replacement indices should be gauged against the attributes of the existing indices. Specifically, the NUG Advisory Committee concluded that any replacement indices should bear the following characteristics:

- Transparent and publicly available;
- Likely to be available for the duration of the term of the NUG contracts;
- Stable;
- As simple as possible to calculate as circumstances permit;
- Easily verified, both historically and on a prospective basis;
- Reflective of electricity prices;
- Ideally, have been in existence on or before the date of the original index took effect (or at least have some historical record);
- Predictable and reasonably forecastable; and
- Related to the energy industry.

OEFC and IPPSO agree that the nature and characteristics of the DCR need to be considered in determining an appropriate replacement index. Specifically, the behaviour of the replacement index in the new open market should be as close as possible to the behaviour that could have been expected of the DCR. Both OEFC and IPPSO recognize that any replacement index should not be subject to significant volatility.

Nature of the DCR

The DCR represented the fully delivered cost of electricity for Ontario Hydro's direct industrial customers for firm power at 100% load factor at either 230 kV, 115 kV or 44 kV and included the cost of the commodity, transmission and all other related charges.

Ontario Hydro, as a regulated monopoly electricity supplier, was for many years able to pass through changes in its costs to customers with relative ease. Ontario Hydro proposed the use of changes in the DCR as a suitable index for purposes of adjusting the contract price of NUG contracts on an annual basis. The DCR was expected, when the NUG contracts were negotiated, to protect the NUGs against general industry-related cost increases, although by its nature it would not fully reflect changes in any particular item.

The cost structure of the former Ontario Hydro and the NUGs was very different since each individual NUG faced costs specific to generation and for the most part, only one type of fuel cost. Ontario Hydro's costs that formed the basis for the DCR reflected its diversified nature as a generation and transmission company. The broad range of costs that comprised the DCR is significant because it contributed to its stability and reduced its volatility.

The DCR was historically a rate based on the former Ontario Hydro's cost structure. At the time when the NUG contracts were entered into, Ontario Hydro's published forecasts contemplated continuing increases in the DCR. However, as a result of the move to an open market and with the establishment of a new replacement index, both the NUGs and OEFC are exposed to price risks. In order to mitigate against this price risk, it has been proposed that the components of the replacement index be averaged over a three-year period. In addition, for those rates in which no floor or minimum increase currently applies, OEFC is proposing to negotiate price floor and price cap provisions which will provide mutual benefit to the NUGS and OEFC by partially mitigating against significant fluctuations (both increases and decreases) in the market prices. The issues of potential DCR decrease and of potential volatility have been carefully considered in the development of the revised DCR definition as discussed below.

DEVELOPMENT OF REPLACEMENT DEFINITION FOR DCR

Discussions between OEFC and IPPSO have focussed on the need to replace the DCR as the index used in the calculation of contract rates in the NUG contracts. The proposed DCR replacement will not in itself replace contract rates.

While the detailed wording of the DCR definition varies slightly from contract to contract, it can be summarized as the fully delivered cost of uninterruptible power at 100% load factor to industrial customers directly connected at the relevant voltage. Both OEFC and IPPSO agree that this concept is the foundation for the revised definition of DCR, as described in detail below.

A number of other indices, including the indices identified in the NUG Advisory Committee report, were considered as a replacement for the DCR, but OEFC and IPPSO agreed that they did not adequately possess the desired characteristics of a replacement index.

OEFC and IPPSO propose that the replacement for the DCR be defined as the fully delivered cost of uninterruptible power at 100% load factor to industrial customers which are wholesale market participants, thereby maintaining the existing definition, as described above. The current components of this definition are set out in the detailed definition below, and can be summarised as:

- Hourly Ontario Energy Price
- Wholesale Market Service Charges
- Transmission Service Charges
- Debt Retirement Charge
- Rural and Remote Electricity Rate Protection
- OPGI Market Power Mitigation Rebate
- For DCR less than 50 kV, applicable distribution losses and service charges.

OEFC and IPPSO believe this proposal reasonably addresses many of the issues regarding the replacement of the existing definition of DCR and represents an acceptable approach to determining an appropriate replacement for the historic determination of DCR.

Change of Law

OEFC and IPPSO recognize that changes in law, regulations and/or market rules (in any case, a “Change of Law”) will occur from time to time and may result in changes to the items comprising Total Market Cost. In such circumstances, the underlying philosophy and definition of DCR will be maintained in order to preserve the original economic effect of Total Market Cost. A Change of Law does not include changes in the amounts or rates of those items comprising Total Market Cost. The calculation of Total Market Cost will be amended as a result of any such Changes in Law to ensure that it continues to reflect the cost of uninterruptible power at 100% load factor to wholesale market participant industrial customers at the relevant voltage. In making any adjustments to the items comprising Total Market Cost as a result of a Change of Law, OEFC will not act arbitrarily and will undertake industry consultations. It is anticipated that the implications of any Change of Law will be dealt with on a contract by contract basis. This Change of Law provision is not intended to affect any other provisions in the PPAs dealing with change of law matters.

Voltage Levels

Historically, there were three separate DCRs based on customers connected at 230 kV, 115 kV and finally those under 115 kV. Rates for those customers at 115 kV were derived from a cost of service study, with a high voltage discount applied to the 230 kV customers reflecting that fewer transformation facilities were required to service 230 kV customers. Under the new market pricing structure, this discount will no longer exist[1].
All direct 115 kV and 230 kV customers will pay the same network and line connection rates unless they own their own line connections[2]. In the absence of a separate rate for 230kv customers, under the proposed replacement for the DCR the same rate will apply to both 230 kV and 115 kV customers. In future, if customer tariffs are adjusted to include unique rates for customers served at voltages higher than 115 kV, the replacement index will be adjusted accordingly. As noted in detail below, for those customers below 115 kV the new market pricing structure does allow for distinct rates to be calculated.

Volatility

The proposed replacement for the DCR incorporates the cost of electricity as a commodity using the Hourly Ontario Energy Price which is the Ontario wholesale spot market price determined by the Independent Electricity Market Operator (IMO). The Hourly Ontario Energy Price is expected to constitute approximately 60% of the values comprising the DCR replacement. It is important to recognize the potential impact of volatility for any replacement index that is heavily influenced by spot market price movements. While hourly and daily price volatility is mitigated by the use of an annual average total market cost, the risk remains that

1 Confirmed by the Pricing and Strategic Support department of Hydro One

2 Although those customers that own line connections are comprised currently of 230 kV customers only (3 of 19 total 230 kV customers), it is possible for both 115 kV and 230 kV customers to own line connections. Therefore, the line connection discount is not specifically associated with the customer’s voltage.

annual average spot market prices may fluctuate due to unanticipated changes to market supply or demand characteristics. Therefore, it has been proposed that the components of the replacement index be averaged over a three-year period to mitigate the potential volatility that may arise as a result of these annual spot market price fluctuations. Total Market Cost in its entirety is being averaged instead of merely the Hourly Ontario Energy Price component because it provides a more flexible framework for response to future regulatory changes. The selection of an appropriate averaging period was based on the expected minimum average period required for market price swings to revert to the mean price through adjustments to electricity supply and/or demand. While recognizing that all price fluctuations will not correct within this timeframe, it is reasonable to expect that a three-year averaging period should capture the mean reversion[3] characteristic of electricity markets. A shorter period may be insufficient to capture this response, and as the averaging period increases beyond three years, the transparency and simplicity of the calculation may decrease without materially reducing volatility.

Rates With Floors and Rates Without Floors

Certain of the existing rates to which the DCR applies have floors or minimum increase provisions and others do not have floors or minimum increase provisions. The proposed replacement of the DCR applies to those rates which have floors or minimum increase provisions. With respect to such rates, it is proposed that the baseline rates will not be changed and the means of calculating the rate will not change. However, the escalation of such rates, to the extent that the DCR currently applies, will be modified by replacing the old definition of the DCR with the new definition of the DCR. In order to further mitigate volatility in contracts with floors, the replacement definition of the DCR will provide that in any given year the DCR will not be less than the previous year's DCR.

With respect to rates to which no floor or minimum increase provision applies, OEFC is not prepared to introduce a replacement index that includes a built in floor. Therefore, for those rates in which no floor or minimum increase currently applies, OEFC proposes that the historical DCR will be replaced by a new negotiated pricing mechanism which will be based on the fully delivered cost of electricity, including the cost of the commodity, transmission and all other related charges. Since the proposed replacement index for the DCR is heavily influenced by spot market price movements, it exposes OEFC and the NUGs to possible volatility and significant pricing changes which were not contemplated at the time the existing contracts were arranged. In order to address these risks, OEFC has stated that in connection with the new pricing mechanism, it is prepared to negotiate a price floor and a price cap to partially mitigate against significant fluctuations in market prices.

Base Period

Many PPAs establish a base period for determining future price escalation. For most contracts

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3 As outlined by Navigant Consulting, mean reversion refers to the tendency for electricity prices to revert to fundamental market levels based on the long-run average cost of production and customer demand. Although power prices may diverge from the mean, in an open and competitive wholesale market, supply and/or demand will respond to price signals until equilibrium is once again achieved. Assuming a reasonable process exists for environmental assessments and construction permits for new generation, a three-year averaging period should be sufficient to capture the market's response to periods of imbalance.

the base period is the year in which the contract started. Since the replacement index is believed to replicate the scope, nature and behaviour of the DCR as it currently exists, it is proposed to continue to use the historical DCR for the purposes of base year calculations. Therefore, there will be no need to change the base year DCR currently referenced in the PPAs.

Transition

In the transition from the current DCR to the replacement index it is necessary to ensure that any increases to the replacement index in the first year should be the result of changes in the cost of the underlying components of the index, as opposed to variations between the structure of the new index and the DCR. OEFC and IPPSO believe that this requirement is fulfilled by the proposal described below.

REPLACEMENT DEFINITION FOR DCR – OVERVIEW

The general successor to the historical calculation of DCR will be referred to as the DCR_{new}. The DCR_{new} will be derived from the Total Market Cost (TMC) and will include the cost of the commodity, transmission and all other related charges. The TMC in any year is calculated as the total cost per kWh of electricity delivered, on a 100% load factor firm basis, to a Wholesale Market Participant customer connected at the relevant voltage, averaged over the relevant year. The detailed description below sets out the scope of items included at market opening. The detailed description will be updated from time to time as required to reflect changes in market rules and regulations.

OEFC will perform the calculations and will publish the DCR and its derivation. These calculations will be verified by an independent third-party. These calculations must be completed and published within sixty (60) days of the end of the relevant six-month period.

The DCR_{new} is the average TMC over the current year and the two prior years, subject to the provision that it cannot be less than the DCR for the previous year, and subject to transition arrangements over the first three years of the market.

The data required for calculation of TMC for any year will not be complete until after the end of the year. It will therefore be necessary to make provisional assessments of DCR_{new} values and contract prices as a basis for ongoing settlement. These will be subject to true-up at half-year intervals to reflect updated information.

For those rates in which no floor or minimum increase currently applies, as discussed above, OEFC is prepared to negotiate a new pricing mechanism. The new pricing mechanism will be based on the fully delivered cost of electricity, including the cost of the commodity, transmission and all other related charges. In connection with the new pricing mechanism, OEFC will negotiate the inclusion of price floor and price cap provisions which will provide mutual benefit to the NUGs and OEFC by mitigating against dramatic fluctuations (both increases and decreases) in market prices.

REPLACEMENT DEFINITION FOR DCR – DETAIL

*Definition*s

Total Market Cost = TMC(P) = cost per kWh of electricity delivered on 100% load factor firm basis to a Wholesale Market Participant load customer connected at the relevant voltage for the year P.

Upon market opening, the TMC is comprised of the following items totalled and averaged over the year:

- Hourly Ontario Energy Price as determined by the IMO (re: Market Rules: chapter 9, section 3.1.3)
- Wholesale Market Service Charges, including:
  - Hourly Uplift[4] (re: Market Rules: chapter 9, section 3.9.2)
  - Ancillary Service Payments[5] (re: Market Rules: chapter 9, section 4.2)
  - IMO Administration Charge, as approved by the OEB (re: Market Rules: chapter 9, section 4.5.1)
  - TR Clearing Account Disbursements (credit) (re: Market Rules: chapter 9, section 4.7.2)
  - Additional Non-Hourly Settlement Amounts (re: Market Rules: chapter 9, section 4.8)
- Transmission Charges
  - For PPAs referencing DCR at 230 kV or 115 kV: Network transmission and line connection at rates approved by the OEB.
  - For PPAs referencing DCR at 44 kV or lower voltage: Hydro One Networks Inc. Retail Transmission Rates in respect of network, line connection and transformation connection, at rates approved by the OEB.
- LV Charge (if applicable)
  - For PPAs referencing DCR at 44kV or lower voltage: Hydro One Networks Inc. Retail LV charge, at rates approved by the OEB.
- Distribution Service Charge (if applicable)
  - For PPAs referencing DCR at 44kV or lower voltage: Hydro One Network Inc. Distribution Service Charge for such large industrial customers, comprising a monthly charge, apportioned over 5 MW demand and a demand charge.
- Debt Retirement Charge, as determined by the Ministry of Finance.
- Rural and Remote Electricity Rate Protection, as determined by the OEB.
- OPGI Market Power Mitigation Rebate (credit) (re: Market Rules: chapter 9, section 5.1.3)
- For PPAs referencing DCR at 44 kV or lower voltage, adjustment in respect of

4 Recovery by the IMO of costs incurred in respect of Net Energy Market Settlement Credit; Operating Reserve Market Settlement Credit; Capacity Reserve Market Settlement Credit; Congestion Management Settlement Credit; Transmission Rights Settlement Credit; Offer Guarantee Settlement Credit; Transmission Charge Reduction Fund Contribution; Capacity Reserve Settlement Debit for Operating Deviations; Operating Reserve Settlement Debit for Operating Deviations for Class R Reserve; and/or other items as determined by the IMO.

5 Recovery by the IMO of costs incurred in respect of IMO contracts for reliability must-run, certified black start facilities, regulation, reactive support service and voltage control service and/or other items as determined by the IMO.

total distribution system loss factor for primary metered customers, in respect to the following items / categories from the list above:

- Hourly Ontario Energy Price
- Wholesale Market Service Charges
- Transmission Charges
- LV Charge (if applicable)
- Rural & Remote Electricity Rebate Protection
- OPGI Market Power Mitigation Rebate

Final DCR_{new} (P) is defined as the greater of Final DCR_{new}(P-1) and the average TMC over year P and the two prior years.

Final DCR_{new} (P)= the greater of [TMC(P-2) + TMC(P-1) + TMC(P)]/3 and Final DCR_{new} (P-1)

This is subject to the transition arrangements as described below.

The proposed DCR replacement will have no impact on the Index Factor calculation and price calculation as currently detailed in the PPAs. In general, NUG contracts currently adjust contract prices based on changes in the DCR through the application of an index factor to the contract price. Annual changes in the replacement DCR will be determined as noted above and the index factor calculation will continue to be applied on the basis specified in the relevant NUG contract.

Timing and Adjustments

The final calculation of DCR_{new} (P) will only be made when all the necessary information is available. During the period in which the OPGI rebate is applicable, this will typically be no earlier than mid year (P+1) as the rebate amount will be in part dependent on market outcomes in January to April (P+1). After the OPGI rebate ceases to be applicable, it is expected that the final calculation should be possible by February (P+1).

It is therefore necessary to develop provisional / interim pricing rules as a basis for payments prior to that. Provisional pricing is the pricing determined in advance of each half year. Interim pricing is determined retrospectively on the basis of semi-annual updates, until final pricing is available. It was recognized that the current price in any given year may differ significantly from the provisional price determined at the start of the year. Therefore, to mitigate the amount and delay associated with any year-end adjustment, it is proposed that semi-annual updates be made to the provisional price. Semi-annual adjustments were selected to minimize the administrative costs (versus quarterly adjustments) and to capture the lower volatility inherent in semi-annual prices as compared to quarterly prices.[6]

The following are proposed:

Provisional DCR_{new}: For each half year (HY) in year (T), the provisional DCR(HY) will be the average of TMC from (HY-6) to (HY-1) (i.e., the average of TMC over the previous 6 half-year periods)using

6 Although rolling quarterly averages would result in a similar quarter dropping from the calculation as the one now included, this would not occur until the third year of the process since the existing DCR does not change quarterly.

	estimated rebate amounts to the extent that actual rebate amounts are unknown, and subject to transition arrangements as described below.
Interim DCR_{new}:	Interim values of DCR_{new} for each half-year (HY) are calculated by adding actual information from half year (HY) and subsequent half year as such information becomes available, and dropping half year (HY-6) etc from the averaging period.
Pricing:	Provisional pricing will be based on the relevant provisional DCR_{new}. Interim pricing will be calculated retrospectively on the basis of interim DCR_{new} calculations. Final pricing will be calculated retrospectively on the basis of final DCR_{new} calculations.
Provisional Payments:	Provisional Payments in each month of half year (HY) will be based on provisional pricing for that half year.
True-up Payments:	Following the end of each half-year, OEFC will incorporate new or updated data into calculations of parameters and prices applicable to that half-year and any prior half-years for which final prices have not previously been finalized. This update will enable the determination of interim or final prices for prior half-years. Any resulting amounts due to or from the Generator from or to OEFC shall be included in the next monthly invoice, and shall be payable therewith unless negotiated otherwise on an individual basis. *(this will continue after the end of the contract period)*. An example of the sequence of calculation and payment is set out in **Appendix C**.

OPGI Rebate

It is expected that all rates should be available on a definitive basis within two weeks of the end of any half-year, with the exception of the OPGI rebate amount. Until actual amounts are declared by the IMO or OPGI, OEFC will make an estimate of the rebate to the end of each half-year using information from OPGI accounts or other available sources.

PPA Gas Price Compensation Payments

Certain PPAs include provision for OEFC and the NUG to share the risk of gas price changes relative to electricity prices. These compensation payments can only be finalized when final electricity prices are available. Gas price compensation payments would therefore be calculated on a provisional basis at the start of the relevant year (P). Adjustment and true-up would only take place when final pricing information is available. Parties may agree to an ad hoc interim adjustment in the event of material deviations before the final adjustment is due.

Transitional arrangements

The TMC for 2002 will be calculated on the basis of the regulated OPGI rates in force for each month prior to market commencement, and the new TMC calculation described above for all months after market commencement. Calculation of the 2002 TMC is illustrated in

Appendix A.

Special provision is needed in 2002 to clarify the use of Provisional, Interim, and Final DCR and pricing calculations. The provisional and mid-year interim DCR will be equal to the DCR calculated in January 2002 on the basis of regulated OPGI rates then in force. The first calculation to take account of market rates will be the interim calculation in early 2003. The early 2003 interim calculation of DCR 2002 and the Final calculation of DCR 2002 will take account of regulated rates from January 2002 to April 2002, and market rates from May 2002 to December 2002.

Special provisions are needed for DCR_{new} calculation in the three years following market opening. During this period, the prior years' TMC calculations will be based on the regulated rates adjusted to include the full amount of the Debt Retirement Charge (i.e. equal to the rates in force for the period of 2002 prior to market commencement).

For 2002 to 2004, the value of prior years' TMC to be used in the calculation of DCR_{new}, are set out in the following table:

Year	2000	2001
TMC @ 230 kV	5.6848	5.6848
TMC @ 115 kV	5.7369	5.7369
TMC @ 44 kV	5.8698	5.8698

An example of the DCR calculation during this transitional period is shown in **Appendix B**.

Rates Without Floors or Minimum Increases

As discussed in greater detail above, for those rates in which no floor or minimum increase currently applies, OEFC is prepared to negotiate a new pricing mechanism pursuant to which the rate will be changed by the simple average of the TMC over the current year and the two prior years with the inclusion of price floor and price cap provisions.

Framework of Rates with Floor and Cap

For those rates where price floor and price cap provisions are to be added, it is proposed that rates would be calculated in accordance with the terms of the existing power purchase agreement with the new pricing mechanism included, subject to the following:

Rate (t) =? Rate (April 30, 2002[7])*[(1+x*t)] and
Rate (t) = Rate (April 30, 2002[7])*[1+y +y*t]

Where: t = 0,1, 2, 3,… and "Rate" is the applicable rate from the Power Purchase

7 The actual rates paid by OEFC from January 1, 2002 to April 30, 2002 based on the 2002 DCR.

Agreement. (t = 0 in 2002, 1 in 2003, etc.)
x = floor expressed in percentages
y = cap expressed in percentages

An example of the floor and cap arrangement is described in **Appendix D**.

Actual values of floor and cap would be the subject of individual negotiation between the NUG and OEFC.

Timing and Adjustments, OPGI Rebate, PPA Gas Price Compensation Payments and Transitional Arrangements will parallel those defined above.

APPENDIX A

SAMPLE CALCULATION OF TMC FOR YEAR 2002

		Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	total
MONTHLY STATISTICS														
days		31	28	31	30	31	30	31	31	30	31	30	31	365
weekend days		8	8	10	8									
pub holidays		1		1										
peak days		22	20	20	22									
on-peak hours		352	320	320	352									
off-peak hours		392	352	424	368									
total hours		744	672	744	720	744	720	744	744	720	744	720	744	8760
REGULATED RATES (ACTUAL for 115 kV)														
Energy charge														
on peak	c/kWh	5.33	5.33	5.33	4.72									
off peak	c/kWh	4.12	4.12	4.12	3.05									
Demand charge	$/kWmth	12.84	12.84	12.84	8.91									
MARKET RATES (ILLUSTRATIVE)														
HOEP (based on 4.3 yrly avg)	c/kWh					3.58	4.07	4.93	4.71	4.07	3.85	3.85	4.50	
WMSC (based on 0.52 yrly avg)	c/kWh					0.44	0.49	0.60	0.57	0.49	0.47	0.47	0.55	
Tx network	$/kWmth					2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	
Tx connection	$/kWmth					0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	
DRC	c/kWh					0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	
RRP	c/kWh					0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	
Rebate	c/kWh					(0.29)	(0.29)	(0.29)	(0.29)	(0.29)	(0.29)	(0.29)	(0.29)	
TOTAL MARKET COST CALCULATION														
Total market cost per month	c/kWmth	4,775	4,440	4,736	3,675	3,732	4,012	4,856	4,670	4,012	3,956	3,840	4,499	
Total market cost for the year	c/kWhyr													51,203
TMC = total market cost / kWh	c/kWh													5.85

APPENDIX B

SAMPLE CALCULATION OF DCR DURING TRANSITIONAL ARRANGEMENTS

	1999	2000	2001	2002	2003	2004	2005	2006
Regulated DCR (P) @ 115 kV	5.04	5.04	5.45	5.74				
Avg annual HOEP assumption				4.30	4.39	4.47	4.56	4.65
TMC (P)								
Historic, incl DRC adjustment	5.74	5.74	5.74					
Current, based on HOEP assumption, Regulated tariffs, estimated rebate etc				5.85	5.89	5.97	6.05	6.39
DCR (old calc)	5.04	5.04	5.45					
DCR (new calc)				5.78	5.83	5.91	5.97	6.13

APPENDIX C

TIMING, ADJUSTMENT AND TRUE-UP EXAMPLE

Example of the sequence of calculation and payment as set out in the "Timing and Adjustments" section of the report. In this example, year 2004 is used as the sample year. This adds a degree of complexity as it is still within the period in which transition provisions apply, but should help to demonstrate the application of those transition provisions.

Consider therefore the calculation of provisional, interim, and final pricing for 2004:

- **In Jan 2004, the provisional DCR (2004) is calculated**. This is the greater of
  - Interim DCR (2003) as calculated in Jan 2004 on the basis of all information available at that time, and
  - The average (weighted according to the number of days in each period) of
    - TMC(2001 Jan to Dec), calculated on the basis of the 2001 regulated DCR, adjusted for the DRC addition in Jan to May
    - TMC(2002 Jan to Mar) calculated on the basis of winter rates under the 2002 DCR
    - TMC(2002 April) calculated on the basis of summer rates under the 2002 DCR
    - TMC(2002 May to Dec) calculated on the basis of market rates (which should be final at this time)
    - TMC(2003 Jan to April) calculated on the basis of market rates (which should be final at this time)
    - TMC(2003 May to Dec) calculated on the basis of market rates (which would still be based on estimated OPG rebate)

  This Provisional DCR (2004) is used to calculate the Provisional Index Factors for 2004. The Provisional Index Factors are used to calculate Provisional Contract Rates for 2004. The Provisional Contract Rates are used as the basis for payments for Jan to June 2004.

  Provisional DCR (2004) will be used to calculate any gas price compensation payments for 2004, on a provisional basis.

- **In July 2004, the Interim DCR (2004) is calculated**. This is the greater of
  - Final DCR (2003)
  - The average (weighted according to the number of days in each period) of
    - TMC(2001 July to Dec), calculated on the basis of the 2001 regulated DCR, for each of those months (fully inclusive of the DRC adjustment)
    - TMC(2002 Jan to Mar) calculated on the basis of winter rates under the 2002 DCR
    - TMC(2002 April) calculated on the basis of summer rates under the 2002 DCR
    - TMC(2002 May to Dec) calculated on the basis of market rates (which should be final at this time)

- TMC(2003 Jan to Dec) calculated on the basis of market rates (which should be final at this time)
- TMC(2004 Jan to April) calculated on the basis of market rates (which should be final at this time)
- TMC(2004 May to June) calculated on the basis of market rates (which would still be based on estimated OPG rebate)

This Interim DCR (2004) is used to calculate the Interim Index Factors for 2004. The Interim Index Factors are used to calculate Interim Contract Rates for 2004. The Interim Contract Rates are used as the basis for payments for Jan to June 2004.

In addition, all payments made from Jan to June 2004 will be recalculated using the Interim DCR (2004). OEFC and the NUG will make a True-up payment (which may be in either direction, depending on the direction of price movement) in respect of those months.

- ♦ **In January 2005, Interim DCR (2004) is re-calculated**. This is the greater of
  - ➢ Final DCR (2003)
  - ➢ The average (weighted according to the number of days in each period) of
    - TMC(2002 Jan to Mar) calculated on the basis of winter rates under the 2002 DCR
    - TMC(2002 April) calculated on the basis of summer rates under the 2002 DCR
    - TMC(2002 May to Dec) calculated on the basis of market rates (which should be final at this time)
    - TMC(2003 Jan to Dec) calculated on the basis of market rates (which should be final at this time)
    - TMC(2004 Jan to April) calculated on the basis of market rates (which should be final at this time)
    - TMC(2004 May to Dec) calculated on the basis of market rates (which would still be based on estimated OPG rebate)

This Interim DCR (2004) is used to re-calculate the Interim Index Factors for 2004. The Interim Index Factors are used to re-calculate Interim Contract Rates for 2004. The Interim Contract Rates are used to recalculate all payments made from Jan to Dec 2004. OEFC and the NUG will make a True-up payment (which may be in either direction, depending on the direction of price movement) in respect of those months.

In addition, this Interim DCR (2004) will be used in the calculation of Provisional DCR (2005)

- ♦ **In July 2005, Final DCR (2004) is calculated**. This is the greater of
  - ➢ Final DCR (2003)
  - ➢ The average (weighted according to the number of days in each period) of
    - TMC(2002 Jan to Mar) calculated on the basis of winter rates under the 2002 DCR
    - TMC(2002 April) calculated on the basis of summer rates under the 2002 DCR

- TMC(2002 May to Dec) calculated on the basis of market rates (which should be final at this time)
- TMC(2003 Jan to Dec) calculated on the basis of market rates (which should be final at this time)
- TMC(2004 Jan to April) calculated on the basis of market rates (which should be final at this time)
- TMC(2004 May to Dec) calculated on the basis of market rates (which would be final at this time)

This Final DCR (2004) is used to re-calculate the Final Index Factors for 2004. The Final Index Factors are used to re-calculate Final Contract Rates for 2004. The Final Contract Rates are used to recalculate all payments made from Jan to Dec 2004. OEFC and the NUG will make a True-up payment (which may be in either direction, depending on the direction of price movement) in respect of those months.

The Final DCR(2004) will be used to calculate any final gas price compensation payments for 2004. OEFC and the NUG will make a True-up payment (which may be in either direction, depending on the direction of price movement) in respect of 2004 gas price compensation payments.[8]

In addition, this Final DCR(2004) will be used in the calculation of Interim DCR(2005).

8 This is based on the assumption that those gas contracts which use DCR in their price calculation can be revised to provide for post facto true-up to final DCR.

APPENDIX D

SAMPLE RATE CALCULATION WITH FLOOR AND CAP

The following chart shows an example of the action of the floor & cap arrangement described in the report section on “Framework of Rates with Floor and Cap”