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Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010

Submission on Behalf of Bord na Móna Energy Ltd

Review of WACC and Economic Lifetime Assumptions

July 2009

NCB

Independent & International

Executive Summary

- In the 2010 consultation paper for the fixed cost of a best new entrant peaking plant (the "2010 Consultation") it has been proposed that the capital cost of the investment in peaking plant be recovered over a 20 year period, rather than the 15 year period previously used.
- At the same time as the period to recover the investment has been decreased, the WACC applied to both the ROI markets and the UK markets has been reduced to its lowest levels since the methodology was introduced in 2006 (the change in assumed location from ROI to UK market shows a pre tax increase in WACC but on a post tax basis the WACC has fallen in both jurisdictions). This reduction in WACC, particularly the equity component, is surprising given the continued economic and financial uncertainty. The increase in the period over which the investment is to be recovered should have the effect of increasing the WACC, all other matters remaining constant.
- The after tax cost of equity assumed for both ROI and UK markets is, in our opinion, below the level that would be required to justify an investment decision in peaking plant under the current framework for cost recovery.
- The fact that the asset may be capable of being operational over a 20 year period does not necessarily mean that this is the appropriate period over which the investment should be recovered for BNE purposes. The Capacity Payment Mechanism ("CPM") is a function of SEM design and is subject to regulatory change. A peaking plant does not have a Power Purchase Agreement ("PPA") or the equivalent of a Regulatory Asset Base ("RAB") and is subject to annual volatility in its income stream, due to market changes (for example increase or decrease in demand) and, equally as importantly, changes in assumptions made by the SEM Committee ("SEMC"), such as the change in economic life from 15 to 20 years.
- In the 2009 Peaking Plant BNE consultation, consideration was given to specifying a residual value for the asset. In comparing a "15 year with residual value" scenario against a "20 year with no residual value" scenario for the 2010 Consultation, we found the implied residual value at the end of 15 years to be in excess of any reasonable estimate of the residual value at such time.
- We have set out in the table below two proposed responses to the consultation:
  a) Adopt a 15 year economic life and apply an 11.9% nominal after tax return on equity (10.0% real) and a 7.5% nominal cost of debt (5.6% real).
  b) Adopt a 20 year economic life and apply a 13.28% nominal after tax return on equity (11.38% real) to account for the higher risk profile.

  As the resultant BNE should be equivalent for (a) and (b), the higher rate for (a) can be attributed to the likely residual value in year 15 that has not been taken into consideration.

	2009	2010p	2010 NCB(a)	2010 NCB(b)
Cost of Debt	4.36%	4.75%	5.60%	5.60%
Cost of Equity (post tax)	9.74%	7.69%	10.00%	11.38%
WACC (pre tax)	7.07%	7.13%	8.92%	9.68%
WACC (post tax)	**6.19%**	**5.13%**	**6.42%**	**6.97%**
Economic Life	15 years	20 years	15 years	20 years
BNE	**€87.12/kW/yr**	**€80.11/kW/yr**	**€97.82/kW/yr**	**€92.44/kW/yr**

1. Introduction

BnM has requested NCB to review and comment on the principal components of the proposed economic and financial parameters as set out in Section 8 of the 2010 Consultation and Appendix 3 to the 2010 Consultation (a report prepared by Cambridge Economic Policy Associated Ltd and Parsons Brinkerhoff (the “CEPA/PB Report”). Accordingly, this paper principally sets out NCB’s views in relation to (i) the proposed extension of the economic lifetime of the plant and (ii) the individual component values of the proposed WACC for ROI/NI.

2. Remuneration of Peaking Plant in CPM

As it is likely that a peaking plant will be the marginal plant dispatched in SEM it is unlikely that a peaking plant will generate inframarginal rent and will therefore receive all of its income from capacity payments (as reduced by expected ancillary services revenue receivable). The amount received from capacity payments is set annually (see Section 3 below) and is subject to annual variation. As a result, a peaking plant is more akin to a financial investment than a strategic investment. The only incentive for a utility to invest under the current CPM rules is if such a participant can either purchase/install or operate/maintain the plant more efficiently than other participants and therefore generate a return which is expected to be in excess of its cost of capital. A utility will not be at a competitive disadvantage if it does not have peaking capacity and its competitors do, where only the cost of capital is recoverable.

The decision to invest or not invest will, therefore, be based on an analysis of the risk adjusted return rather than any strategic concerns which can influence other investment decisions. The BNE methodology will, as a result, have a significant impact on the decision to invest or not – with the changes proposed in the 2010 Consultation in terms of extending the economic life and reducing the WACC serving to disincentivise investment in peaking plant.

3. Relationship Between Peaking Plant and CPM

SEM is a gross mandatory pool which includes a marginal energy pricing system and an explicit Capacity Payment Mechanism (“CPM”). The CPM is a fixed revenue mechanism which collects a pre-determined amount of money (the Annual Capacity Payment Sum (“ACPS”)) from purchasers and pays these funds to available generation capacity in accordance with rules set out in the Trading and Settlement Code (“T&SC”). The value of the Annual Capacity Payment Sum is determined as the product of two numbers:

- A Quantity (the Capacity Requirement), determined as the amount of capacity required to just meet an all-island generation security standard; and
- A Price determined as the fixed cost of a best new entrant (BNE) peaking plant.

In 2009 in the ACPS was €640.9 million based on a capacity requirement of 7,356MW and a BNE Peaking Plant Cost of €87.12/kW/yr. Of the Capacity Requirement of 7,356MW only a small proportion is expected to be provided by plant that would be considered as peaking plant, with the vast majority of the ACPS being paid to baseload and mid merit generators. The SEMC has stated that capacity payments in the SEM perform two main roles[1].

- One is that they provide revenues to cover the capital and fixed costs which are not covered in the SEM by payments for energy. This applies for both potential new investors and for any existing plant (and to baseload stations as well as peaking plant).
- The other is that the capacity payments provide incentives for generators to be available at times when the system needs generation capacity.

4. Recap of CPM Objectives

Set out below are the criteria that have formed the basis of the Regulatory Authorities’ decision making process in relation to the CPM to date[2].

[1] Single Electricity Market Fixed Cost of a Best New entrant Peaking plant Calculation methodology Consultation paper, 9th March 2009 (SEM-09-03)
[2] Single Electricity Market Scope of CPM Medium Term Review, Consultation Paper, 8th April 2009 (SEM-09-035)

1) Capacity Adequacy/ Reliability of the system The CPM must encourage both the construction and maintained availability of capacity in the SEM. Security of the system, will be the core feature of the CPM. 2) Price Stability The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market. 3) Simplicity The CPM should be transparent, predictable and simple to administer, in order to lower the risk premium required by investors in generation. A complex mechanism could reduce investor confidence in the market and increase implementation costs. 4) Efficient price signals for Long Term Investments In theory it would be possible to incentivise vast amounts of capacity over and above that necessary for system security in the SEM, although the cost of implementing such a scheme may be unacceptable to customers. The CPM should meet the criterion in this section at the lowest reasonable cost. Revenues earned by generators should still efficiently signal appropriate market entry and exit. 5) Susceptibility to Gaming The CPM should not be susceptible to gaming and, ideally, should not rely unduly on non-compliance penalties. 6) Fairness The CPM should not unfairly discriminate between participants. An appropriate CPM will maintain reasonable proportionality between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy.

We have set out below our view that the change to the economic life of a peaking plant from 15 to 20 years and the reduction in after tax WACC does not fit with these objectives in that:

- It does not encourage the construction of capacity (which indeed may be the objective of the 2010 Consultation);
- It increases volatility in capacity payments;
- It varies an assumption within the CPM methodology that had not previously been varied signalling to the market that there is risk attached to all variables in the CPM methodology; and
- It does not send a positive signal for investment in peaking plant.

5. Proposed Change to Economic Life of Peaking Plant

The economic life of the project has been taken as 20 years in the 2010 Consultation. Previously 15 years was used with an unspecified residual value, but 20 years with no residual value has now been adopted as more appropriate. By extending the economic life of the plant from 15 years to 20 years the annual capacity payment required to recover the capital cost reduces as there is an increased number of years to recover the investment.

6. Impact of Proposed Change on Return on Investment of a Peaking Plant

- Reduction in annual peaking plant income from €17.066 million to €15.229 million (11% decrease);
- Reduction in ACPS from €613 million to €547 million;
- Change in time taken to recover peaking plant capital cost from 9 years to 10.5 years;
- Equivalent residual value at 15 years equating to movement to 20 years with no residual value of €46.6 million[3] (using a real WACC of 7.13%) which equates to 52% of the original EPC costs. If a nominal WACC is used the percentage of original EPC costs is significantly higher.

[3] The Future Value is calculated as 1.0713^{15} times the required reduction in capital cost to equate to an 11% decrease in annual income (present value of €16.6 million).

As can be seen from the analysis above, the equivalent residual value after year 15 that produces the same impact on BNE as the movement to 20 years is a higher percentage of EPC costs than we would typically expect (land and fuel residual values are already considered in the proposed BNE calculation).

7. SEMC Justification for Increase in Economic Life

The basis for the proposed decision has been justified in the 2010 Consultation and the CEPA/PB appendix with reference to a number of specific points. We have set out in the table below an analysis of these comments.

Ref	SEMC/CEPA/PB [4];	NCB
7.1	It is assumed that the investor is likely to be an integrated utility.	As set out below, an integrated utility is, in making an investment decision in generation assets, likely to consider additional factors over a non integrated (generation only) utility, such as the ability to pass price spikes on to customers where the generation portfolio does not have peaking capacity and competitive position relative to other generators. It is not clear whether the reference to integrated utilities was inadvertent, or an acknowledgement by SEMC that due to the potential for change to the CPM in the medium to long term that only an integrated utility should construct such a plant and that the beta of a peaking plant should be considered as part of a larger generation portfolio integrated with a supply business. If this is the case, this would imply that SEMC does not envisage any of the non integrated generators, which includes BnM Energy, Endesa, AES plc, BG plc, Aughinish Alumina and Tynagh Power constructing a peaking plant.
7.2	There has been a trend of extending the economic evaluation periods of CCGT plants (from 25 years to 30-35 years) and SCGT plants (from 15 to 20 years)	The CEPA/PB Report makes reference in Section 7.1.1 to both the UK market and other unspecified "riskier markets" but does not discuss the 30-35 year time period mentioned by SEMC in Section 8.2. It is unclear whether the trend of extended economic life noted by SEMC is based on SEM experience or from discussions with CEPA/PB relating to other markets. In order to comment on this observation it is necessary to have clarity on the market in question: • The UK market is structured as an energy only market where a generation station must recover its capital and operating costs through the pool, whereas SEM has both capacity and SRMC payment. The UK market has been through a number of regulatory iterations (Pool, NETA, BETTA) whereas SEM is at an earlier stage of its regulatory life. • The business structure of the party making the investment decision will also impact on the investment decision. A long established integrated utility with a large customer base and a significant existing generation fleet, will have different factors to consider when making an investment decision than a smaller, generation only recent entrant to SEM. See point 7.1 above. • Whether the plant has a PPA or not (and the term of such PPA) will also influence the economic evaluation period, as such period will at least extend to the end of the PPA term. Given the nature of CPM (i.e. all of a peaking plant's revenue) and assuming that the SEMC does not intend disadvantaging non-integrated utilities, the only relevant comparison is the economic assessment of an uncontracted (i.e. no PPA) peaking plant.

[4] Source: 2010 Consultation (Section 8.2 and Appendix 3 Section 5.1.2 and 7.1.1)

7.3	An asset life of 25 years was discussed but 20 years was considered to be prudent	The fact that a move to 25 years was discussed but not implemented signals to potential investors that there is a risk that in future years that such a view may be taken by SEMC. This uncertainty serves to increase the perceived risk of the investment increasing the required return on investment (which should be captured by an increase in the asset beta (see Section 8 below)
7.4	20 years is a standard investment horizon for equity investors;	The investment horizon for equity investors (we assume that this relates to equity investment in generation plant) while related to, should be considered a separate matter to the period over which the capital cost can be recovered by way of capacity payments. By seeking to match the investment recovery period with the economic life, this increases the risk profile of the asset as the period to capital recovery and exposure to regulatory change is increased. In the case of a windfarm, which is typically taken to have an economic life of 20-25 years, a 15 year PPA is typically put in place. This allows the capital cost to be fully recovered plus a certain element of the required return during this period. The energy payments for years 16-20 are, at the time of investment, uncertain but a range of likely outcomes can be estimated. A sensitivity analysis is then typically performed on the energy payments for this period to assess the impact on expected return. In the event that a 20 year PPA was on offer there would be a narrower range of outcomes making the investment lower risk in nature therefore requiring a lower return. A purely merchant windfarm would have a much wider range of potential returns increasing the risk and the required return. In the same way, by expecting investors in peaking plant to recover their investment over a 20 year period the risk (and required return) increases. There needs to be a better acknowledgement in the BNE process of the impact of increased cost recovery period on risk levels which increases required return.
7.5	PB has confidential project experience of an economic life of 20 years being used for peaking GTs in the UK.	As set out above, the UK has a different market structure to SEM and is, therefore, of limited relevance in this instance. In order to assess the relevance of this reference we would need to understand the nature of the party making the investment decision and the expected return on investment.
7.6	20 years is the minimum norm where investments are backed by PPA's in riskier markets than SEM;	We would agree that this is the case but question the relevance of this comment. The CPM does not have the same characteristics as a PPA as is subject to annual variation outside the control of the generator (this proposed increase in economic life from 15 to 20 years being a case in point). More importantly, there is no obligation on the RAs to keep the CPM in place and the market structure may change significantly over the next 20 years. In the event that the SEMC was to offer 15-20 year contracts to build, own and operate peaking capacity this would be a more relevant comment.
7.7	Equity investors are willing to accept long term returns from relatively low risk assets and;	We would agree with this comment in principal but question whether it applies to an investment in peaking plant in SEM. Given the changes to the assumptions in the decisions from 2007-2010 and the forthcoming CPM Medium Term Review, a peaking plant would not be considered a low risk investment. An electricity or gas network asset or a windfarm with a 15 year PPA are examples of assets where investors are willing to

		accept long term returns from low risk assets.
7.8	It is assumed that the investor raises debt at the corporate level.	The SEMC has not specified as to whether this assumption was made due to the additional cost of raising project level debt and the unwillingness of utilities to incur this additional cost or whether it was assumed due to the expected difficulty in raising project level debt given the inherent uncertainty applying to the CPM.
7.9	Banks will tend to supply debt with a door to door life of between 13 years and 20 years (they will always want to be paid out before the equity).	There is currently limited debt financing available with a term of greater than ten years. While it has been assumed that the debt is raised at group level rather than project level this does not impact significantly on the likely availability of debt. The increase in the economic life from 15 to 20 years increased the period by which the economic life exceeds the term on available debt, further increasing the risk of the asset. This point does not just relate to investment in peaking plant but the majority of infrastructure assets.
7.10	Equity investors into power generation tend to be willing to take a longer term investment horizon in the knowledge that a longer payback period for debt and equity will make their plant lower cost in terms of annual fixed payments. A plant with a 10 year payback period would be far less competitive in the market than one with a longer investment horizon.	This point does not apply to investments relating to peaking plant, as the owner of the plant has limited ability to determine the competitiveness of the plant relative to other peaking plant given the nature of the CPM.

Summary re Extension of Economic Life

- The arguments put forward by SEMC and CEPA/PB in relation to the extension of the economic life of a peaking plant have been made with limited reference to the type of plant, the dispatch regime and the regulatory context which applies to a peaking plant in SEM. Using examples of different types of plants (CCGTs) and different markets (UK) is not relevant.
- As peaking plants are rarely dispatched in SEM, the remuneration of SEM peaking plant (unlike other plant with a position in the merit order) is highly dependent on the CPM. This results in a variable annual income stream which is outside the control of the generator.
- Given the uncertainly relating to the annual income stream of a peaking plant in SEM, the increase in assumed economic life from 15 to 20 years has a more significant impact on both the expected return and risk profile of a peaking plant than a similar change in assumption would have on a CCGT or a generation asset with a long term PPA.
- There is limited access to long term debt funding in the current market, with 5 to 10 year funding more likely to be put in place than 15 to 20 year funding. By increasing the economic life from 15 to 20 years the refinancing risk associated with the asset increases (the same refinancing risk would apply to all generation assets, other generation assets are not, however, as reliant on annual capacity payments).
- The increase in economic life from 15 to 20 years increases the risk profile of the asset. Not only is this not acknowledged in the 2010 Consultation or the CEPA/PB Paper, but reference is made to investors low return requirements from long term, low risk assets. A peaking plant in SEM is not a low risk generation asset, with a 20 economic life for BNE purposes having a higher risk profile than a 15 year economic life for BNE purposes.

8. WACC Comments

As there are a number of variables in a WACC calculation we have set out in this Section our view on the cost of debt and the after tax cost of equity.

Cost of Debt

The proposed mid point pricing used for the WACC calculation is a nominal rate of 6.65% based on sterling index linked issuances. The CEPA/PB paper states that this is based on 20 year debt.

	ROI			UK		
	Low	**High**	**Mid**	**Low**	**High**	**Mid**
Real	4.5	6.25	5.38	4.0	5.5	4.75
Inflation	1.9	1.9	1.9	1.9	1.9	1.9
Nominal	6.4	8.15	7.28	5.9	7.4	6.65

In the current market, it is has been difficult for European utilities to raise Euro denominated debt of this term, with more availability of Sterling denominated debt where long term funding is required[5]. In terms of pricing we would see 10 year funding costing 7.5% to 8.0% in nominal terms based on recent market issuances, most particularly ESB's recent US private placement [6]. We have taken the lower end of this range, i.e. 7.5% nominal (5.6% real).

Barclays Capital and RBS Greenwich Capital priced a $508 million private placement for Ireland-based Electricity Supply Board last week, sources confirmed. The multi-currency deal was upsized from an original $150 million.

The NAIC-1 deal priced in U.S. dollars, Sterling, and euro, in a total of eight tranches, with 16 investors participating.

The U.S. dollar tranches priced as follows; the four-year tranche priced at 370 basis points over Treasurys, the five-year tranche at 395 bps, the seven-year at 395 bps, the 10-year at 395 bps.

The five- and 10-year euro-denominated tranches priced at 295 bps and 315 bps over mid-Swaps, respectively. The eight- and 12-year Sterling-denominated tranches priced at 401 bps and 344 bps over Gilts, respectively. A total of 16 investors participated in the deal.

Cost of equity

The CEPA/PB Report has settled on a mid point nominal return on equity of 9.59% (post tax)

	ROI			UK		
	Low	**High**	**Mid**	**Low**	**High**	**Mid**
Real	6.9	8.75	7.81	6.9	8.5	7.69
Inflation	1.9	1.9	1.9	1.9	1.9	1.9
Nominal	8.8	10.65	9.71	8.8	10.4	9.59

Based on our recent market experience, an investor would not invest in an asset with the risk profile of a peaking plant in SEM for an after tax nominal return on equity of less than 10%, (particularly as noted in Section 2 that under SEM a peaking plant has limited strategic value as it is not expected to generate inframarginal rent).

In our opinion, the nominal after tax return on equity required would be in the range of 12% to 14% per annum, with the upper end applying in the current environment where a high level of volatility/uncertainty exists, reducing to the lower end of the range as volatility reduces and there is greater certainly (which may or may not arise as a result of the CPM Medium Term Review). The proposed after tax return on equity for 2010 should not only be seen in light of current market expected returns but also in the context of previous BNE decisions. As set out in the table below, the nominal after tax cost of equity for 2006 to

[5] RBS Investment Grade Research – Utilities Half Term Report 20 July 2009.

[6] http://www.privateplacementletter.com/news/-193907-1.html

2009 has been in the range of 12.14% to 15.53%, which ties into our experience of current market expectations, as set out above. The proposed after tax cost of equity for 2010 of 7.81% real/9.71% nominal would suggest that, in the current environment, investors would be willing to take a lower level of reward for a given level of risk than they have been for the period 2006 to 2009. We do not consider this to be an accurate picture of the current investment environment and would suggest that a range of 12% to 15% remains appropriate.

	2006	**2007**	**2008**	**2009**	**2010**
Post tax Cost of Equity (Real)	12.44	12.92	12.93	9.74	7.81
Inflation	2.2	2.6	2.6	2.4	1.9
Post tax Cost of Equity (Nominal)	14.64	15.52	15.53	12.14	9.71

The after tax cost of equity is a factor of risk free rate, tax rates, equity risk premium, asset beta and gearing. We would consider each of the changes to assumptions set out below to be conservative, and when taken together the resulting cost of equity to be very conservative. In particular, we feel that the low asset beta reflects neither the historic variability in annual BNE, nor the expected volatility/exposure to regulatory change over the economic life, such uncertainty having been increased as a result of the proposed extension to economic life from 15 years to 20 years.

	2009 ROI	**2010 ROI**	**Change**
Real Risk Free Rate	2.11%	1.88%	Reduced
Equity Risk Premium	5.5%	4.75%	Reduced
Asset Beta	0.56	0.50	Reduced
Gearing	60%	60%	-
Tax Rate	12.5%	12.5%	-
Pre Tax Cost of Equity (Real)	11.3%	8.93%	Reduced
Post Tax Cost of Equity (Real)	9.74%	7.81%	Reduced

The asset beta is a key driver of the cost of equity. There are limited appropriate comparators for a peaking plant in SEM from which to derive an asset beta.

The key factors influencing the BNE peaking plant's asset beta include[7]:

- Exposure to price and volume risk. These may rise or fall due to systematic factors related to economic growth.
- The existence of the capacity payment mechanism means that generators are to a certain degree protected from general price and volume risks related to economic growth; against this however,
- High fixed costs of a BNE magnify the effect of underlying systematic (price and volume) risk.

Our qualitative assessment of the non-diversifiable operational systematic risk of a BNE peaking plant leads us to conclude that it is reasonable to assume an asset beta for the investment of around 0.5. We note that this is greater than the delevered asset betas for UK utilities of around 0.4 and in line with the implied asset betas for international airports of 0.517.

The example above of UK utilities and international airports does not take into consideration the fact that these companies typically have a Regulatory Asset Base (RAB) and 5 year price reviews, which reduce volatility significantly. A peaking plant has no equivalent of a RAB, and therefore if an investment decision in a peaking plant is made in a given year and capital costs fall significantly thereafter the investor will not be compensated for such fall, as the annual BNE is calculated with reference to the capital cost of the year in question.

[7] CEPA/PB Report A1.9.2

The annual BNE price has been volatile since its inception, suggesting that a low beta is not appropriate:

	2007	2008	2009	2010
BNE	64.73	79.77	87.12	80.11
% Change		23.2%	9.2%	(8.0%)

WACC Summary

We have set out, in the table below, two suggested WACC (pre-tax) rates:

- **NCB (A).** WACC of 8.92%. Based on a 15 year economic life and applies an 11.9% nominal after tax return on equity (10.0% real) and a 7.5% nominal cost of debt (5.6% real)[8].
- **NCB (B).** WACC of 9.68%. Based on a 20 year economic life and applies a 13.28% nominal after tax return on equity (11.38% real) to account for the higher risk profile. Nominal cost of debt as per NCB (A) 7.5% (5.6% real).

	ROI 2009	**NI 2010**	**NCB (A) NI-2010**	**NCB (B) NI-2010**
Risk Free Rate (Nominal)	4.56%	N/D	N/D	N/D
Inflation	2.40%	N/D	N/D	N/D
Risk Free Rate (Real)	2.11%	1.75%	1.75%	1.75%
Debt Premium	2.25%	3.00%	3.85%	3.85%
Cost of Debt (Real)	**4.36%**	**4.75%**	**5.60%**	**5.60%**
Equity Risk Premium	5.50%	4.75%	5.50%	5.50%
Tax	12.50%	28.00%	28.00%	28.00%
Asset Beta	0.56	0.50	0.60	0.70
Equity Beta	1.39	1.25	1.50	1.75
Post-Tax Cost of Equity	**9.74%**	**7.69%**	**10.00%**	**11.38%**
Pre-Tax Cost of Equity	11.13%	10.68%	13.90%	15.80%
Gearing	60.00%	60.00%	60.00%	60.00%
Leverage	150.00%	150.00%	150.00%	150.00%
Post-Tax WACC	6.19%	5.13%	6.42%	6.97%
Pre-Tax WACC	**7.07%**	**7.13%**	**8.92%**	**9.68%**

Note: in the event that the plant location was assumed to be ROI rather than NI, the impact of the decrease in tax rate from 28% to 12.5% would be to reduce the pre tax WACC under (A) to 7.94% and under (B) to 8.56%.

[8] Assumes inflation of 1.9%