Response to AEMC questions about the recovery of transmission connection charges and other costs

Submission on behalf of the Victorian electricity distributors

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Revision Log

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1. Comparison with existing arrangements

In assessing the Rule change proposal, the Commission will need to compare the proposed Rule with the current arrangements. Under the current arrangements, assuming that DNSPs would be able to recover these charges (i.e., transmission service costs, inter-DNSP charges and avoided TUOS charges) as operational expenditure under the distribution determination process, what would be the impact on DNSPs to recover these costs through the determination process rather than as a pass through? How does this compare with the impact on DNSPs if the Rule was made (i.e. what benefits does the proposed Rule provide)?

The AEMC's question in relation to the current arrangements for the recovery of the cost components mentioned (that is, transmission service costs, inter-DNSP charges, and avoided TUOS charges) presupposes that DNSPs have an option, under the existing provisions of the National Electricity Rules (**NER**), to categorise these cost components as operating expenditure. As set out below, these cost components do not currently form part of the forecasts for operating expenditure as part of a distribution determination in:

- Queensland, South Australia and NSW, under distribution determinations made by the AER pursuant to Chapter 6 (or equivalent transitional provisions) (see section 1.1); or

- Victoria under the current Electricity Distribution Price Review (see section 1.2).

As discussed in section 1.3 of this response, these cost components should not necessarily be characterised as forecast operating expenditure pursuant to clause 6.5.6 of the NER. The recovery by distributors of transmission service costs, inter-DNSP charges and avoided TUOS charges is clearly consistent with the national electricity objective and with the revenue and pricing principles. However, the classification of the applicable cost components as operating expenditure, and the recovery thereof via forecast operating expenditure, would not promote the national electricity objective, (see section 1.3.1), and the revenue and pricing principles, (see section 1.3.2), to the same degree as would a recovery of the constituent costs through the distributors' annual pricing proposals.

The Rule change proposal involves explicitly providing for the recovery of the cost components via the annual pricing proposal process. There is a direct transmittal of the actual costs through to consumers via a maximum transmission revenue formula. The direct pass through ensures that a DNSP will recover only its actual charges, while simultaneously providing an assurance to end-users that they will only pay for the actual expenses incurred by a DNSP in respect of the relevant cost components. As is explained in section 1.4 of this response, the approach set out in the Rule change proposal has considerable merit over an alternative method which might result in DNSPs having to characterise the relevant cost components as forecast operating expenditure.

1.1 Current arrangements in Qld, SA and NSW under AER distribution determinations

As noted in the Rule change proposal, the "current arrangements" under Chapter 6 of the NER, as they are applied and interpreted by the Australian Energy Regulator (**AER**) in a number of jurisdictions including Queensland[1], South Australia[2] and New South Wales[3], involve the recovery of "all transmission related payments" as pass through amounts in the relevant DNSP's pricing proposal. The term "all transmission related payments" is used in reference to the following charges:

- Transmission charges to be paid to TNSPs.
- Avoided TUOS payments; and
- Inter-DNSP payments.

It is only in relation to the Victorian DNSPs, and without explanation, that the AER has indicated that it does not consider that clause 6.18.7 operates to permit the DNSPs to recover all transmission related payments, in particular, transmission connection charges. In this context of regulatory uncertainty, the Victorian DNSPs consider that the current practice of the AER should be explicitly incorporated into clause 6.18.7, and this is precisely what the draft Rule proposal is aimed at achieving.

The Victorian DNSPs are not aware of any DNSP with a relevant distribution determination made by the AER under Chapter 6 which recovers charges associated with transmission connection costs, avoided TUOS payments and inter-DNSP payments as part of an operating expenditure forecast pursuant to clause 6.5.6 of the NER. That is, the Victorian DNSPs understand that all DNSPs that have a relevant distribution determination made by the AER under Chapter 6, (or relevant transitional provisions), recover transmission-related costs as pass through amounts which are approved pursuant to their annual pricing proposals.

As is explained in section 1.3 below, the presumption should not be made that DNSPs are able to recover all transmission-related payments as forecast operating expenditure pursuant to clause 6.5.6. Even if it were feasible, an outcome of this nature would not necessarily be desirable from a policy perspective.

1.2 Current arrangements in Victoria under the EDPR 2006 – 10

At present, the Victorian DNSPs calculate and submit proposed transmission tariffs to the Australian Energy Regulator (**AER**), making use of a maximum transmission revenue control formula which is set out in clause 3.3 of the Electricity Distribution

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[1] Australian Energy Regulator, *Final Decision: Queensland Distribution Determination 2010 – 11 to 2014 – 15*, 6 May 2010, Appendix E, pp 395 – 396.

[2] Australian Energy Regulator, *Final Decision: South Australia Distribution Determination 2010 – 11 to 2014 – 15*, 6 May 2010, Appendix F, pp 322 – 323.

[3] Australian Energy Regulator, *Final Decision: New South Wales Distribution Determination 2009 – 2010 to 2013 – 14*, 28 April 2009, Appendix I, pp 462 – 263.

Price Review, 2006-10, Price Determination (Volume II)[4]. The proposed transmission tariffs are the tariffs for transmission services which recover the following: Charges for connection to, and use of, the transmission system; amounts for payments to embedded generators (or avoided customer TUOS charges); and inter-DNSP payments. The arrangements that currently apply in Victoria are similar to those that apply in Queensland, South Australia and New South Wales pursuant to recent distribution determinations made by the AER under Chapter 6.

The maximum transmission revenue control formula draws upon data over a three-year period, and contains a correction factor, K_t, to account for any under or over recovery of actual transmission revenue in relation to allowed transmission revenue. The equation is set out in clause 3.3.2(i), as shown below:

$$MTR_t = TC_t + G_t - D_t - K_t$$

Where:

MTR_t is the maximum transmission revenue (in dollars) which the distribution business is allowed to earn from its transmission tariffs levied on all distribution customers in the calendar year t.

TC_t is the aggregate of all charges (in dollar terms) for connection to and use of the transmission system which, in the judgement of the distribution business, will be payable to VENCorp and SPI PowerNet, or to any other party holding a Victorian electricity transmission licence during calendar year t. Clause 3.3.2(i) states that payments should comply with any relevant guidance in force from time to time.

G_t is the amount, in dollars, that the distribution business expects to remit to embedded generators during calendar year t, with the payments having been verified as being compliant by either the AER or the ESCV.

D_t is the revenue (in dollars) which the distribution business believes that it will earn during calendar year t from other distribution businesses, in respect of inter-network provider distribution service tariffs. The expected revenue should be measured net of similar charges which, in the opinion of the business, will be paid to other distribution businesses during calendar year t.

K_t is the correction factor determined in accordance with clause 3.3.3 of Volume II of the Electricity Distribution Price Review, 2006 to 2010.

The maximum transmission revenue, (MTR_t), formulation establishes a satisfactory and transparent mechanism for the recovery of costs by DNSPs in circumstances in which the cost components vary on an annual basis for reasons which are unrelated to actions taken by DNSPs. The costs of accessing and using the transmission

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4 Electricity Distribution Price Review, 2006-10, October 2005 Determination as amended in accordance with a decision of the Appeal Panel dated 17th February 2006. Final Decision Volume 2 Price Determination.

system may change due to factors which lie beyond the realm of control (and outside the sphere of influence) of DNSPs, either individually or collectively.

The MTR_t method relies upon forecasts for year t, estimated outcomes for year t-1, and actual data for year t-2. A virtue of the method is that it helps to ensure absolute accuracy in cost recovery, while also giving rise to relatively modest price movements on the way to achieving the recovery. Full cost recovery, and a relatively stable price path are both desirable features of any form of pass through mechanism.

1.3 What would be the impact on DNSPs recovering transmission related costs through the determination process rather than as a pass through?

There is a degree of ambiguity about the proposition that DNSPs are able to recover all transmission-related payments as forecast operating expenditure pursuant to clause 6.5.6. Even if it were feasible, the classification of transmission-related payments as operating expenditure would not necessarily be desirable from a policy perspective.

In relation to the first issue – whether DNSPs can recover all transmission related payments as forecast operating expenditure pursuant to clause 6.5.6 - a pertinent consideration is the nature and type of operating costs, in respect of which the DNSP is preparing forecasts for the distribution determination process. In its building block proposal, a DNSP may only include the components of total forecast operating expenditure which, in the judgement of the business, are needed to achieve the operating expenditure objectives. These objectives include a requirement to:

- Meet or manage the expected demand for standard control services.
- Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.
- Maintain the quality, reliability and security of supply of standard control services; and
- Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

The operating expenditure objectives all relate to the provision of standard control services – which are direct control services that are subject to a control mechanism based on a DNSP's total revenue requirement. No automatic inference can be drawn as to the closeness of the relationship between the operating expenditure objectives and the provision of transmission services. There is therefore some doubt as to the inclusion in forecast operating expenditure of charges for services provided by the transmission system, inter-DNSP payments and avoided customer TUOS charges.

Furthermore, if the AER is not satisfied that the total of the forecast operating expenditure reasonably reflects the operating expenditure criteria, then the AER must not accept the forecast of required operating expenditure. The operating expenditure criteria are as follows:

- The efficient costs of achieving the operating expenditure objectives; and

- The costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the operating expenditure objectives; and

- A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Again, these considerations are directed squarely at the provision of direct control services – and not at services provided by the transmission system.

Setting aside the issue of whether transmission service charges, inter-DNSP payments and avoided customer TUOS charges could form part of a DNSP's forecast operating expenditure, there remains an outstanding policy question of whether a framework that provides for the recovery of these charges as a part of forecast operating expenditure is either desirable or preferable to the current counterfactual.

A DNSP would encounter obstacles when preparing forecasts of inter-DNSP payments, avoided customer TUOS charges, and costs associated with transmission services (such as transmission connection costs). The hurdles placed in a DNSP's path are related to regulatory processes, and the involvement of third parties, and can be characterised as follows:

- The charges incurred for prescribed transmission services are essentially determined through the AER's transmission determination for the relevant TNSP, which consists, *inter alia*, of a revenue determination for the TNSP in respect of the provision of prescribed transmission services, and a determination which specifies the pricing methodology that applies to the TNSP. The relevant transmission determination in Victoria is that which applies to SP AusNet during the period 2008–09 to 2013–14. This determination expires on 31 March 2014 and there is an expectation that it will be superseded by a new determination applying from 1 April 2014. The distribution determinations to be made by the AER will apply to the Victorian DNSPs until 31 December 2015. As there are so many unknowns, the Victorian DNSPs simply do not have the capacity to anticipate, with any degree of accuracy, the outcome of a regulatory decision which is scheduled to be brought down in three and a half years from the present date.

- The charges that will be incurred for prescribed transmission services even within the SP AusNet transmission determination period, which expires on 31 March 2014, are not necessarily certain. The charges for these services may increase or decrease as a result of pass through events or contingent projects. There is also the possibility that the existing transmission determination could be reopened and adjusted in the event that a major flaw or inadequacy is uncovered.

- A complication associated with developing predictions of avoided TUOS charges is that the DNSPs do not have adequate information as to future connections of new embedded generation. The DNSPs cannot foresee the number of new generator connections (and the output associated with each connection) over the five year term of a regulatory control period.

In short, DNSPs have little or no influence over charges for transmission services, distribution services provided by other DNSPs, or avoided customer TUOS charges. The lack of influence arises partly due to the factors set out above, but also due to other considerations. Accordingly, a DNSP would face significant challenges if it sought to prepare forecasts of the stated cost components, and the risk of forecasting error would be high.

Since there is a strong likelihood of over or under-stating the predicted costs, then DNSPs would be exposed to prospective windfall gains or losses depending upon the outturn values of the uncontrollable costs.

From a policy maker's perspective, there is little merit in permitting DNSPs to retain the benefits which result from over-prediction of the relevant charges. DNSPs are unable to exert control over the level of the charges and should not be given incentives to "outperform" the forecast costs. There is no need to establish a parallel with other components of operating expenditure which are genuinely controllable, and in relation to which adequate incentives for cost minimisation are already in place.

In limited circumstances, a DNSP might seek to delay connections to the transmission system and attempt to reduce remittances for avoided TUOS. The latter course of action would conflict with the policy objective of promoting the connection of new embedded generation. In general, a DNSP would be constrained from engaging in unusual conduct because of the risk of contravening other aspects of the National Electricity Rules, however behavioural change could still be recorded at the margin.

Even if the operating expenditure on transmission-related payments were exempted from the structure of the Efficiency Benefits Sharing Scheme, a DNSP would still have an incentive, and particularly in the early years of the regulatory period, to seek to minimise charges for transmission services, inter-DNSP payments and avoided customer TUOS charges.

If a DNSP incurred lower charges for these services than it had forecast, then the savings would not necessarily reflect a relevant cost efficiency on the part of the DNSP. To allow a DNSP to keep the benefit of any over-prediction of charges for transmission services, inter-DNSP payments and avoided customer TUOS charges would be inconsistent with the incentive framework in Chapter 6, which permits a DNSP to retain the benefits of cost efficiencies.

Similarly, there would be little rationale from a policy maker's perspective in having DNSPs incur losses resulting from the under-prediction of charges for transmission services, distribution services provided by other DNSPs and avoided customer TUOS charges. Since any monetary losses would not be a consequence of cost inefficiencies on the part of the DNSPs, then it would be arbitrary and inequitable to expect DNSPs to bear the burden of the under-recovery.

There is no evidence that DNSPs would face greater incentives to strive for efficiency, and thus there would be no improvement to the attributes of the regulatory framework by comparison with the current situation.

1.3.1 Consistency with the national electricity objective

As previously mentioned, there is a high degree of error associated with forecasting charges for transmission services, distribution services provided by other DNSPs and avoided customer TUOS charges. The consequences of such errors are potentially significant (notably, a windfall gain in the event of over-forecasting and monetary losses in the event of under-forecasting). Accordingly, a framework which provides for DNSPs to forecast these charges as part of their forecast operating expenditure in the distribution determination process is unlikely to be consistent with the national electricity objective.

Specifically, the objective of efficient investment in, and efficient use of electricity services, particularly with respect to price, will not be promoted or enhanced in circumstances in which a DNSP bears the risk that outturn costs will differ materially from projected costs for expenditure items over which the DNSP can exert little or no control.

The proposed Rule change supports the national electricity objective and would benefit both customers and DNSPs alike. If implemented, the proposed Rule would permit DNSPs to recover transmission service costs as a form of pass through within their annual tariff proposals. The transmission tariffs charged to customers would then be a direct function of the actual costs paid by DNSPs. If, in any one year, a DNSP over-recovered its pass-through costs, then prices in the following year would come down so as to offset the over-recovery. Similarly, if, in any year, a DNSP under-recovered its pass-through costs via tariffs, then prices in the following year would need to increase so as to recoup the under-recovery amounts. Hence, if the proposed Rules are implemented, then customers will gain by paying prices for transmission services which reflect the actual costs incurred by DNSPs, of which the vast majority are regulated transmission services costs. Similarly, the DNSPs will be better placed because the impact on their cash flows will be neutral in NPV terms. There will be no undesirable effects on the incentives to connect embedded generators or to make payments to these entities.

1.3.2 Consistency with the revenue and pricing principles

A framework which provides for DNSPs to forecast charges for transmission services, distribution services provided by other DNSPs, and avoided customer TUOS charges is also unlikely to be consistent with the revenue and pricing principles. In particular, a DNSP is unlikely to be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services if it has to bear the risk of forecast error. A DNSP could alternately gain or lose significant dollar amounts if outturn costs are substantially lower or higher than forecast values.

1.4 Benefits of the proposed Rule

The Rule change proposal involves explicitly providing for the recovery of the cost components via the annual pricing proposal process. A distribution tariff approval template is submitted to the AER as part of the annual pricing proposal. The maximum transmission revenue, (MTR_t), formula is a component of the tariff approval template, and its application to recover transmission service payments and related costs ensures that end-users only pay for the actual charges incurred by a DNSP. The DNSP, in turn, is assured of recovering its actual charges for transmission related services. For the reasons set out in section 1.3.1, the use of the annual pricing proposal process to recover these charges is consistent with the national electricity objective and with the revenue and pricing principles.

The benefits of the proposed Rule include:

- Certainty as to the recovery of actual charges incurred by the DNSP, which is appropriate in circumstances in which the DNSP has little to no control over transmission-related payments, and would face significant difficulty in attempting to forecast the charges over a five year regulatory period.

- Contributing to the achievement of the national electricity objective and the revenue and pricing principles.

- Facilitating the recovery by DNSPs of their actual expenditure in relation to transmission cost components; and

- A standardisation of practice across the respective jurisdictions.

For the reasons discussed in section 1.3, and on account of other factors, the Victorian DNSPs have strong reservations about the categorisation of transmission service charges as operating expenditure. The DNSPs would therefore not be in favour of a requirement to prepare forecasts of the constituent costs in the context of their regulatory proposals.

2. The value of inter-DNSP charges, avoided TUOS payments, and transmission-related service fees

What is the magnitude of the inter-DNSP charges, avoided TUOS charges and transmission-related service charges?

The values of the respective charges are presented below in Table 2.1 (with costs reported in thousands of dollars). The cost components have been taken from the distribution tariff templates (or pricing proposals) which are prepared annually by each DNSP and submitted to the AER. The tariff approval templates for years leading up to and including 2009 were lodged with the Essential Services Commission, Victoria.

Table 2.1: A breakdown of transmission service and other charges paid by distributors

Values in $'000	**2006**	**2007**	**2008**	**2009**	**2010**
Transmission related service charges					
Citipower	$8,863	$9,349	$9,520	$8,228	$7,992
Jemena	$6,816	$7,106	$7,407	$7,332	$8,478
Powercor	$16,967	$17,978	$18,278	$16,258	$17,626
SP AusNet	$9,866	$10,325	$11,438	$12,427	$12,796
United Energy	$12,225	$12,961	$12,198	$10,370	$9,513
Sum of transmission-related service charges	**$54,738**	**$57,719**	**$58,841**	**$54,616**	**$56,404**
Inter-DNSP charges					
Citipower	$4,708	$3,743	$2,720	$3,998	$3,161
Jemena	-$2,567	-$2,818	-$3,190	-$3,424	-$4,243
Powercor	$643	$868	$1,061	$1,575	$1,617
SP AusNet	-$1,585	-$1,821	-$1,675	-$1,675	-$1,675
United Energy	$558	-$1,671	-$1,488	-$919	-$919
Sum of inter-DNSP charges	**$1,758**	**-$1,698**	**-$2,573**	**-$446**	**-$2,059**
Avoided TUOS charges					
Citipower	$0	$0	$0	$0	$0
Jemena	$113	$70	$447	$308	$155
Powercor	$0	$39	$1,128	$1,083	$546
SP AusNet	$184	$320	$512	$589	$602
United Energy	$0	$0	$0	$0	$0
Sum of avoided TUOS charges	**$298**	**$429**	**$2,087**	**$1,980**	**$1,302**
Avoided transmission charges					
Citipower	$0	$0	$0	$0	$0
Jemena	$478	$533	$582	$655	$687
Powercor	$0	$0	$0	$0	$0
SP AusNet	$8,174	$8,446	$8,719	$9,017	$9,305
United Energy	$0	$6	$6	$6	$6
Sum of avoided transmission charges	**$8,652**	**$8,986**	**$9,307**	**$9,678**	**$9,997**

Values in $'000	2006	2007	2008	2009	2010
Aggregate of all itemised charges	**$65,445**	**$65,436**	**$67,662**	**$65,828**	**$65,645**

Source: Annual tariff submissions (pricing proposals) submitted by Victorian DNSPs to the AER (formerly to the ESCV). Note that inter-DNSP charges do not sum to zero, partly because of payments made to, and receipts earned from, inter-state distributors. Over the historical period as shown, Powercor made payments to ETSA Utilities and earned revenues from Australian Inland Energy and Water, whilst SP Ausnet made payments of comparatively small value to Country Energy.

A significant component of ‘other charges’ is avoided transmission costs. Two DNSPs currently report charges in this category, Jemena and SP AusNet. SPI Electricity (SP AusNet) makes payments for avoided transmission costs to the owners of the Bairnsdale Power Station, in the context of a network support agreement which was negotiated and finalised in 2001. The avoided transmission charges reflect the opportunity cost of building a transmission link between Morwell and Bairnsdale, in the State’s east, and are also representative of the capital and operating costs that would have been incurred in the construction and commissioning of a terminal station in Bairnsdale. The network support agreement was approved by the ESCV and is expected to remain in place until 2020. The avoided capital and operating and maintenance costs have been amortised over the life of the agreement.

Avoided transmission costs are reported as separate line items in the ‘TUOS cost audit template’ and are aggregated with avoided TUOS charges.

The values shown in Table 2.1 for 2006, 2007 and 2008 are actual amounts reported in the ‘TUOS cost audit templates’ prepared by Victorian DNSPs as part of their annual tariff submissions. The figures for 2009 are estimates, though some distributors have provided actual results where these have become available. Forecast data has been used for 2010, and the projections shown are consistent with those recorded against the maximum transmission revenue formula.

SP AusNet has specified more precisely the combination of actual and estimated data that has been used to derive its figures, and the arrangements for different time periods are summarised by the scheme shown in Table 2.2.

Table 2.2: SP AusNet scheme for evaluating cost components for different time periods

Charge Component	Y_{t-2}	Y_{t-1}	Y_t
AEMO Transmission Use of System (TUOS) charges	Actual outcomes	Actual data for 9 months, plus estimates based on approved transmission price path	Estimates based on approved transmission price path
Transmission connection fees (payable to SPI Powernet)	Actual outcomes	Actual data for 9 months, plus estimates based on approved transmission price path	Estimates based on approved transmission price path
Inter-DNSP payments/revenue	Actual outcomes	Actual data for 9 months, plus estimates based on the most recent actual, equivalent period, adjusted for known network configuration changes.	Estimates based on most recent actual equivalent period, adjusted for known network configuration changes.
Avoided TUOS	Actual outcomes	Estimates based on the most recent recorded outcomes, with adjustments for forthcoming embedded generation projects.	Estimates based on the most recent recorded outcomes, with adjustments for forthcoming embedded generation projects.
Network support payments (avoided transmission connection charges)	Actual outcomes	Actual data for 9 months, plus estimates based on network support payment (NSP) contracts.	Estimates based on network support payment (NSP) contracts.

Source: SP AusNet.

3. Calculation of avoided TUOS charges

How are the avoided TUOS charges calculated? For instance, with respect to avoided TUOS payments, we note that the ESCV has provided a guide on how to calculate avoided TUOS payments. Are you aware of how this has been calculated in other jurisdictions?

The method currently applied to the calculation of avoided TUOS charges is set out in Appendix 1 to this document. The Victorian DNSPs conform to the guidance note published by the ESCV when working out this cost component[5].

JEN has entered into a contract with AEMO (formerly known as VENCorp) to independently calculate avoided TUOS charges. Citipower and Powercor have set out their procedures in detail, and these have been documented in the attached note (see Appendix 2).

United Energy sought information from inter-state distributors on the method of calculation of avoided TUOS charges, but was unable to obtain suitable documentation.

[5] Open Letter to Stakeholders and Interested Parties. Guidance on calculation of avoided TUOS payments. Essential Services Commission, Victoria, 19th October 2005.

4. Provision of data on transmission service costs

Under the proposed Rule, is it envisaged that DNSPs would set out details of what transmission service charges were incurred (either in the distribution determination process or under the pricing process)? What were the arrangements under the Electricity Distribution Price Determination with regard to setting out details of the transmission service charges incurred?

The proposed Rule specifically provides for an amendment to clause 6.12.1(19), which provides that a constituent decision of a distribution determination is a decision on how the DNSP is to report to the AER on its recovery of: Transmission services; distribution services provided by other DNSPs; and avoided customer TUOS charges. Therefore, under the proposed Rule, it is envisaged that DNSPs would report to the AER on these charges in a manner which is consistent with the reporting requirements set out in the distribution determination for each DNSP.

Under the current arrangements in the EDPR, which are set out in Volume II of the Price Determination for the EDPR 2006 to 2010[6], the annual pass-through costs are submitted as part of the annual tariff proposals, and are recovered through the maximum transmission revenue control. The transmission service charges are subject to an under and over-recovery mechanism so as to ensure that customers do not pay amounts in excess of actual costs.

There are extensive requirements in place for auditing the data on transmission costs. Attachment 12 of Volume II of the EDPR, 2006 to 2010, stipulates that a distribution business must provide the Regulator with an agreed upon 'procedures report' which has been prepared by an independent auditor. The procedures report is a component of the regulatory accounts and covers the data which underpins the maximum transmission revenue formula in section 3.2.3. The intention is that the data in the procedures report should reconcile with information in a cost audit template which forms a part of the annual pricing proposal submitted by each DNSP.

Accordingly, when submitting their annual pass-through tariffs to the AER, Victorian DNSPs are obliged to disclose and itemise their actual costs, and their forecasts of pass through costs. The enclosed workbook for UED incorporates worksheets showing the cost audit template, and the maximum transmission revenue formula (see Appendix 3).

Furthermore, in the context of their annual pricing proposals for the year 't', the Victorian DNSPs are also obliged to provide the AER with statements of certification or verification by their respective boards. Each DNSP lodges a statement signed by its board of directors which attests to the veracity of the actual audited pass through costs incurred in year 't-2". The verified actual costs feed into the 'under' and 'over' correction components of the maximum transmission revenue control.

To the extent that the current arrangements set out above are considered to be appropriate, then they could be incorporated into a constituent decision of a distribution determination pursuant to clause 6.12.1(19). The constituent decision

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[6] Electricity Distribution Price Review, 2006-10, October 2005 Determination as amended in accordance with a decision of the Appeal Panel dated 17th February 2006. Final Decision Volume 2 Price Determination.

would govern how a DNSP is to report to the AER on the recovery of the appropriate cost components, notably, TUOS charges under the current Rules, and an array of charges under the proposed Rule. The charges under the new Rule are of course comprised of transmission service costs, distribution services provided by other DNSPs, avoided customer TUOS payments, and, potentially, avoided transmission charges.

In the AER's draft distribution determination for the Victorian DNSPs, the AER has indicated that it requires the following from DNSPs in their report to the AER on the recovery of TUOS[7]:

- Detailed calculations showing the charges that the DNSPs incurred for TUOS, including the unders and overs component;

- A presentation of the calculations according to the format set out in Appendix F.2 of the draft determination;

In addition, the AER has stipulated that the dollar amounts submitted for the most recently completed regulatory year must be audited. Amounts for the current and next regulatory year will be regarded as estimates and forecasts respectively

Attachments

Appendix 1 – Calculation of avoided TUOS payments

Appendix 2 – Citipower and Powercor: Documented procedures for assessing the value of avoided TUOS.

Appendix 3 – UED Distribution Tariff Approval Template for 2010.

[7] **Draft decision, Victorian electricity distribution network service providers. Distribution determination 2011-2015. Appendices. Appendix F.1, Introduction to Transmission Tariffs, page 16.**

Appendix 1. Calculation of avoided TUOS payments

Clause 5.5(h) of the National Electricity Rules (NER) provides the basis for the proposition that connection applicants (which include embedded generators) should be paid TUOS fees in circumstances in which their generation activities result in the avoidance of payment for transmission services by DNSPs. Clause 5.5(i) of the NER describes the essential elements of a method for working out avoided TUOS, and these principles have been endorsed by the ESCV, and also transformed into a set of workable procedures. The ESCV referred to the calculation of avoided customer TUOS usage charges in its Guideline Number 15, on the connection of embedded generation[8]. In October 2005, the ESCV released a further guidance note on the calculation of avoided TUOS payments[9].

In the guidance note, the ESCV stated that the avoided cost payment should be the difference between the TUOS usage charges that would apply with and without the generator injecting energy into the network. The calculation of the actual TUOS usage charges was described by VENCORP in its publication, *Electricity Transmission use of System Prices, 1 July 2005 to 30 June 2006*. The updated results of the calculation have been provided in more recent editions of the same document.

The TUoS Usage price is a location-specific price based on summer demand, which is believed to capture the long run marginal cost of transmission at each connection point. The TUOS location-specific price is assessed using the cost reflective network pricing methodology. The prices are on a dollar per MW basis, and are applied to the average of the top ten summer peak demands at a point of supply, measured at half hourly intervals on weekdays from 1st November 2010 until 31st March 2011, between the times of 11.00am and 7.00pm. The period and the times over which maximum demand is measured have been prescribed by the AER in section 2.2 of its Pricing Methodology Guidelines for electricity transmission network service providers[10].

The average of the top ten summer maximum demands is calculated both inclusive and exclusive of the impact of embedded generator output. The avoided TUOS charge is worked out by multiplying the avoided demand by the usage rate or location-specific price applicable to the relevant terminal station.

The application of the aforementioned calculation method means that the avoided TUOS charges payable to embedded generators will be contingent on generation output on the ten occasions of peak summer demand. The Victorian DNSPs are not privy to the information which would enable them to forecast this level of output accurately. The DNSPs also do not have prior knowledge as to when the peak demand periods will eventuate.

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[8] *Electricity Industry Guideline No. 15. Connection of Embedded Generation, Issue 1.* Essential Services Commission, Victoria, August 2004.

[9] Open Letter to Stakeholders and Interested Parties. Guidance on calculation of avoided TUOS payments. Essential Services Commission, Victoria, 19th October 2005.

[10] Electricity transmission network service providers. Pricing methodology guidelines, Final, October 2007. Australian Energy Regulator, 29th October 2007.

As has been previously noted, a further complication with developing predictions of avoided TUOS charges is that the DNSPs do not have adequate information as to future connections of new embedded generation. The DNSPs cannot foresee the number of new generator connections (and the output associated with each connection) over the five year term of a regulatory control period.

<u>Powercor and CitiPower Avoided TUOS</u>

1. Document Purpose

This document outlines the process for calculating Avoided Transmission Use of Service ("TUOS") payments and the procedures for paying / recovering funds. It explains how Avoided TUoS regulatory obligations are to be discharged.

2. Regulatory Background

Section 5.5(h) of the National Electricity Rules (**"Rules"**) requires that Embedded Generators be paid TUoS fees where their generation activities result in Distributors avoiding payment for transmission services.

Guidance on how to calculate Avoided TUoS is provided in Section 5.5(i) of the National Electricity Rules and has been provided by the Essential Services Commission (**"Commission"**) in their *Guideline for Embedded Generation* (27 July 2004) and in an open letter to stakeholders and interested parties titled "Guidance on calculation of avoided TUoS payments" (19 October 2005).

3. What is Avoided TUoS

Avoided TUoS payments are paid to Embedded Generators in lieu of transmission fees. These payments compensate Embedded Generators for connecting directly to the distribution network, allowing transmission businesses to avoid capital expenditure costs.

4. Components in calculation

TUoS charges are made up of 3 components; Usage Charges, General Charges and Common Service Charges. Section 3.2 of the "Guideline for Embedded Generation" (July 2004) specifies that only the Usage Charge is avoidable. Usage charges are thus the only component of TUoS charges included in the calculation of Avoided TUoS.

5. Methodology

The following process outlines the method that Powercor will use to calculate Avoided TUoS:

a. Step 1 – Determine calculation period

The calculation period, *t*, is the summer period spanning 1 November to 31 March in a given financial year.

b. Step 2 – Collect Data

Interval meter data, *i*, must be available for the period. Interval meter readings are usually taken every 15 minutes for a Terminal Stations and Embedded Generators.

Where the metered interval, *k*, differs between the Terminal Station and the Embedded Generator the readings will be converted to the larger interval. This is achieved by summing the energy over the smaller intervals to match the larger time interval.

Not all interval data is used in the Avoided TUoS calculation. The variable *j* is a subset of *i* that only includes data recorded between 7am and 11pm on weekdays.

Variables:

t: *Financial year represented in the Avoided TUoS calculation*
i: *Set of interval data*
j: *Sub-set of interval data over period t for 7am to 11pm weekdays*
k: *Period of time in minutes between interval readings*

Powercor will collect interval data for the period from all relevant NMIs at relevant Terminal Stations and reconcile this data to data provided by the Embedded Generator or a contracted third party. Where discrepancies may exist between the two data sets the parties will negotiate in good faith to agree on the correct data set.

c. Step 3 – Calculate new Maximum Demand (MD): where there is one Embedded Generator

i. Apportionment of Energy

For the purposes of calculating Avoided TUoS the energy produced by the Embedded Generator must be allocated to one or more Terminal Stations.

Where the Embedded Generator is connected to the distribution network in a location wholly serviced by one Terminal Station, all energy delivered by the Embedded Generator will be allocated to that Terminal Station. Where the Embedded Generator is connected to the distribution network in a location that is serviced by multiple Terminal Stations the energy will be apportioned between the Terminal Stations in accordance with the appropriate engineering calculations.

Calculations are to be determined such that:

$$\sum_{m=1}^{n} p_m = 1$$

Variables:

p: *Proportion of energy to be assigned to each Terminal Station*
n: *Number of Terminal Stations linked to the Embedded Generator*
m: *Terminal Station*

ii. Calculate the MD at the Terminal Station (MD10)

For each Terminal Station and for each set of interval data, *j*, the summer Maximum Demand (MD10) will be calculated as follows:

$$MD_{mj} = r_{mj} \times 60/k$$

Variables:

MD_{mj}: *Maximum Demand for interval j at Terminal Station m*
r_{mj}: *Interval reading in MWh for interval j at Terminal Station m*

The average of the set of 10 highest daily demand values, *MD_{mj}*, will be deemed the Maximum Demand, *MD10*, for the Terminal Station.

iii. Calculate the MD including the Embedded Generator (MD10')

For each Terminal Station, *m*, and for each set of interval data, *j*, the summer Maximum Demand including Embedded Generator impacts, MD10', will be calculated as follows:

$$MD'_{mj} = \left(r_{mj} + s_j \times p_m\right) \times 60/k$$

Variables:

MD'_{mj}: *Maximum Demand for interval j at Terminal Station m*
r_{mj}: *Interval reading in MWh for interval j at Terminal Station m*
s_j: *Interval reading in MWh for interval j at the Embedded Generator*
p_m: *Proportion of energy allocated to Terminal Station m*

The average of the set of 10 highest daily demand values, *MD'_{mj}*, will be the deemed Maximum Demand inclusive of Embedded Generator impacts, *MD10'*, for the Terminal Station.

d. Step 4 – Determine the Avoided Demand (aMD10)

For each Terminal Station, *m*, Avoided Demand, *$aMD10_m$*, is represented by the difference between the *$MD10'_m$* and *$MD10_m$*. That is:

$$aMD10_m = MD10'_m - MD10_m$$

e. Step 5 – Calculate the Avoided TUoS Charge

For each Terminal Station, Avoided Demand, *$aMD10_m$*, will be multiplied by the usage rate, *R*, applicable to the Terminal Station, *m*. Usage rates are published by VENCorp for each summer period.

Avoided TUoS (the **"Avoided TUoS Amount"**) for each Terminal Station will be summated to give the total Avoided TUoS for the Embedded Generator.

$$AvoidedTUoS = \sum_{m=1}^{n} aMD10_m \times R_m$$

Variables:

R_m: *Usage rate in dollars for Terminal Station m for the period t*

f. Step 6 – Avoided TUoS Shared Benefit

In some cases, contractual agreements may exist for sharing of Avoided TUoS payments. Where such arrangements exist the Avoided TUoS Amount will be apportioned as specified by the contract.

6. Avoided TUoS calculations – two Embedded Generators connected to one Terminal Station

The following outlines the method to calculate Avoided TUoS where there are 2 Embedded Generators connected to one Terminal Station.

a. Step 1 – Determine calculation period - as per 5(a) above

b. Step 2 – Collect Data – as per 5(b) above

c. Step 3 – Calculate new Maximum Demand (MD)

i. Apportionment of Energy

Where there is more than one Embedded Generator connected to the distribution network in a location that is serviced by only one Terminal Station, all energy delivered by Embedded Generators will be allocated from the one Terminal Station.

ii. Calculate the MD at the Terminal Station (MD10) – as per 5(c)(ii) above

iii. Calculate the MD including the Embedded Generator (MD10')

For each Terminal Station, *m*, and for each set of interval data, *j*, the summer Maximum Demand including Embedded Generator impacts, MD10', will be calculated as follows:

$$MD'_{mj} = \left(r_{mj} + s_j + t_j\right) \times 60/k$$

Variables:

MD'_{mj}:	*Maximum Demand for interval j at Terminal Station m*
r_{mj}:	*Interval reading in MWh for interval j at Terminal Station m*
s_j:	*Interval reading in MWh for interval j at the Embedded Generator*
t_j:	*Interval reading in MWh for interval j at the Embedded Generator*

The average of the set of 10 highest daily demand values, MD'_{mj}, will be the deemed Maximum Demand inclusive of Embedded Generator impacts, *MD10'*, for the Terminal Station.

d. Step 4 – Determine the Avoided Demand (aMD10)

$$aMD_{10} = MD10'_m - MD10_s - MD10_t$$

Where:

$$MD_s = (r_{mj} + s_j) - r_{mj} \times 60 / k$$

$$MD_t = MD'_m - MD_s - MD_{mj}$$

Variables:

MD'_m: Maximum Demand for interval j at Terminal Station m inclusive of impacts at Embedded Generator s and t
MDs Maximum Demand for interval j at Embedded Generator s
MDt Maximum Demand for interval t at Embedded Generator t

e. Step 5 – Calculate the Avoided TUoS Charge – as per 5(e) above

7. Regulatory approval

Regulatory approval from the AER is required before payment is made to the customer.

8. Timing of undertaking calculations

Powercor will calculate the Avoided TUoS Amount and notify the retailer within 2 weeks of receiving actual data from the Terminal Station meter data provider and the Embedded Generator or relevant metering agent. If this time frame cannot be adhered to then Powercor will negotiate a revised time frame in good faith.