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22nd December 2011

Proposed Rule change: Distribution Losses

Mr John Pierce
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
Sydney NSW 2000
Email: submissions@aemc.gov.au

Dear Mr. Pierce,

The Copper Development Centre (CDC) has a longstanding interest in promoting energy efficiency and strongly supports the objectives of the National Strategy on Energy Efficiency. The CDC is conscious of the very important role that distribution network investment plays in improving the efficiency of electricity delivery.

Prior to the establishment of the National Electricity Market (NEM), integrated distribution and retail businesses were responsible for purchasing bulk energy. Electricity distributors purchased the energy lost in their networks and thus had some incentive to reduce losses. That is no longer the case. In the current regulatory environment, DNSPs manage and develop the distribution networks. DNSPs are not responsible for the cost of lost energy and indeed have powerful economic regulatory incentives to minimise their capital and operating costs, at the expense of increasing loss costs.

On 21st December, I wrote on behalf of the Copper Development Centre (CDC) to suggest a minor modification to the AEMC's proposed Rule change on the Distribution Distribution Network Planning and Expansion Framework. As with transmission investments, that change would require the AER to provide guidance to Distribution Network Providers (DNSPs) on the valuation of losses, for major capital investments for Distribution.

At the time, I foreshadowed the CDC's intention to propose a Rule change that would require the DNSPs and the Australian Energy Regulator (AER) to take into account the cost of losses in distribution investment decisions, where that cost is material. This proposed Rule change, together with the Distribution Framework, is designed to ensure that the cost of losses is appropriately recognised in all DNSP investment decisions.

The CDC's proposed Rule change on Distribution Losses is attached to this document. I would also like to convey my appreciation of the open and cooperative response by AEMC officers In advising of the protocol to be followed in submitting this proposal.

Also attached is a paper describing an appropriate methodology to determine the long-run cost of losses for distribution investments[1]. This methodology values the following cost components:

- The long-run incremental cost of generation, based on AEMO's research;
- The long run marginal costs of expanding the upstream distribution and transmission networks to deliver energy to the point at which it is consumed, or lost; and
- The incremental upstream losses to deliver energy to the point in the network at which it is consumed, or lost.

This review has indicated that the long-run marginal cost of electrical losses, which is appropriately used in evaluating distribution investments, is much greater than the average market value of energy. Moreover, as there is now greater clarity concerning the implementation of carbon pricing in Australia, this needs to be factored into the long-run cost of losses.

In summary, the economic regulatory framework for network businesses needs to more closely align with energy efficiency policy frameworks. This is particularly important for critical investment decisions being taken today, concerning assets that will service the needs of future generations.

Please do not hesitate to contact me, if further explanation of this submission would assist the Commission with its deliberations. Our experts will be made available to help clarify any issues this submission raises.

Yours sincerely,

John J Fennell
Chief Executive Officer
Copper Development Centre • Australia Ltd

Attachments:

1. Rule change proposal – Distribution Losses
2. Technical Paper – Loss Costs

1 Colebourn H, The cost of losses for future network investment in the new networks regime. Presented to the September 2010 conference of the Electric Energy Society of Australia conference in Sydney in September 2010.

Proposal for change to National Electricity Rules - Distribution Losses

This proposal for a change to the National Electricity Rules (the Rules) is authorised and submitted by John J Fennell, Managing Director of the Copper Development Centre (CDC, the Proponent of this Rule change). The full name and address of the Proponent of the Rule change is as follows:

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ABN 40 067 486 300
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100 William Street
Sydney NSW 2011

The covering letter submitted with this Rule change proposal is signed by CDC's CEO, authorising this submission.

Subject matter of Distribution Losses Rule change

This Distribution Losses Rule change proposal seeks to ensure that the cost of the electrical losses in distribution networks is appropriately recognised in all capital and operating investment decisions made by electricity distributors. As this proposal relates to:

> "regulating the activities of persons (including Registered participants) participating in the national electricity market ..."[1];
>
> it falls within the matters on which the AEMC is permitted to make changes to the Rules.

The proposed Distribution Losses Rule change would add a requirement that a DNSP must consider the cost of losses, in preparing the operating and capital expenditure forecasts that form part of a building block proposal.

Relationship of proposed Rule change to other Rule change proposals

There are two Rule change proposals currently under consideration by the AEMC, concerning related matters, or affecting the same clauses in the Rules, as this Distribution Losses Rule change proposal. These are as follows.

Distribution Planning and Expansion Framework

The Distribution Planning and Expansion Framework Rule change proposed by the Ministerial Council on Energy (MCE) seeks to build on the existing differing jurisdictional arrangements. This proposed Rule change has the following main elements:

- A requirement for DNSPs to perform an annual planning review;
- A requirement for DNSPs to publish a 5-year planning report;
- A requirement for DNSPs to use a case by case assessment of economic options (termed the Regulatory Investment Test for Distribution (RIT-D)[2]); and
- A dispute resolution process.

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1 National Electricity (South Australia) Act 1996 Version 1.1.2010, Section 34(1)(a)(3).

2 Distributors are currently required to use the Regulatory Investment Test (RIT).

The Australian Energy Regulator (AER) would be required by this Rule change to develop the RIT-D and associated Application Guidelines. The RIT-D applies to distribution investments of greater than $5 million[3]. The RIT-D principles require consideration of the changes in electrical energy losses[4].

The proposed Application Guidelines do not contain a requirement for the AER to provide guidance on the economic value to be ascribed to the cost of losses. This is the subject of a proposed modification to the Distribution Planning and Expansion Framework Rule change submitted by the CDC, which is also relevant to this Distribution Losses Rule change proposal[5].

In summary, whilst the Distribution Planning and Expansion Framework Rule change proposal requires distributors to consider the change in energy losses for capital investments of greater than $5 million, it does not apply to the other types of distribution investments that are the subject of this Rule change. By extending the requirement for distribution losses to be considered in all classes of distribution investment, this Distribution Losses Rule Change is complementary to the proposed Distribution Planning and Expansion Framework Rule change.

Economic Regulation of Network Service Providers

The Economic Regulation of Network Service Providers Rule change has been proposed by the AER, with the objective of improving the effectiveness of the economic regulatory framework. The AER's proposed amendments to the Rules would alter the capital and operating expenditure framework, by removing some of the restrictions on the AER's ability to assess and respond to proposals[6].

The AER's proposed Economic Regulation of Network Service Providers Rule change would amend Rule clauses 6.5.6(c)-(f) (on operating expenditure) and 6.5.7(c)-(f) (capital expenditure) for DNSPs[7]. Similar changes are also proposed for TNSPs.

The CDC's proposed Distribution Losses Rule change would add subclauses 6.5.6(b)(1A) and 6.5.7(b)(1A) to the operating and capital expenditure forecast requirements, respectively. This proposal therefore does not affect the same clauses as the AER's Economic Regulation of Network Service Providers Rule change proposal. Nor would the proposed requirement for the operating and capital expenditure forecast requirements, to include the consideration of electrical losses, impinge in any way on the AER's proposal to modify the way in which expenditure forecasts prepared by the DNSP are assessed in regulatory determinations.

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3 AEMC, Proposed Rule (marked up) clause 5.6.5CB(a)(2).

4 ibid, clause 5.6.5CA(c)(4)(vii)

5 CDC, Submission to the Distribution Network Planning and Expansion Framework Rule change proposal, XX November 2011.

6 AER, Rule change proposal - Economic regulation of transmission and distribution network service providers - AER's proposed changes to the National Electricity Rules, September 2011.

7 AER, Rule change proposal - Economic regulation of transmission and distribution network service providers --AER's proposed changes to the National Electricity Rules -Part C – Draft Rules, September 2011, pp. 22-26.

2 Description of the proposed Rule change

Capital and operating expenditure forecasts by the DNSPs form the basis of building block determinations made by the AER. For distributors, these forecasts are prepared in accordance with Rules provisions 6.5.6 and 6.5.7.

The forecasts must be prepared by the DNSP in order to achieve the operating and capital expenditure objectives set out in these clauses and meet certain forecast requirements. Moreover, the forecasts are assessed by the AER against those same objectives and forecast requirements. The forecasts are accepted only if the costs are efficient, prudent represent a realistic expectation of the demand forecast and cost inputs required to achieve the expenditure objectives.

The proposed amendment would add sub-clauses 6.5.6(b)(1A) and 6.5.7(b)(1A) to the Rules. This would require:

- DNSPs to consider the cost of distribution losses when preparing their forecasts of operating and capital expenditure to meet the expenditure objectives; and
- The AER to assess whether the cost of losses had been given appropriate consideration in the DNSP's forecast when making a distribution determination.

Draft wording of the proposed Rule change is set out in the Appendix.

3 Issues with the existing Rules

The structure of the National Electricity Market (NEM) is designed to facilitate trading between the market participants (Generators and Retailers) across the transmission and distribution systems. In the NEM, electrical losses occurring in networks are taken into account in trading, using the following adjustment mechanisms:

- Distribution losses are accounted for by volume adjustments, using distribution loss factor adjustments between the point of transmission connection and the distribution connection
- Transmission losses are accounted for by adjustments to the Regional Reference Price, using transmission loss factors at the point of each transmission connection;
- Discrepancies between the marginal transmission loss factors and settlement outcomes in the market form part of the settlement residues and adjust transmission charges.

Losses are effectively accounted for in the market by these loss factor mechanisms. Transmission system losses are generally in the range of 1% to 3%, whereas distribution system losses can represent an average of from 5% to 15% or more. The value of the losses consumed within networks is therefore substantial and is largely recovered from the customers connected to distribution networks.

3.1 Losses in electrical networks

The losses consumed within a network are influenced by many factors, including:

- The load and generation patterns and the capacity and utilisation of network assets;
- The specification of network assets (conductor sizes and transformer characteristics); and
- The configuration in which the network is operated.

Network losses may never be eliminated, but rather optimised to an economically efficient level, where the marginal benefit of reducing them is balanced against the marginal capital or operating expenditures required to reduce them.

The NEM regulatory framework does not make TNSPs and DNSPs responsible for the cost of losses within their networks. These businesses are subject to revenue or price regulation and are not set up to manage the trading activities and risks associated with buying a substantial quantity of energy from the market to supply losses.

If network businesses were responsible for the purchase of losses, in minimising their costs they would then also seek to reduce the cost of losses. However, the CDC recognises this would represent a substantial change to the existing market framework and the risk profile of the network businesses and so has not proposed this option.

3.1.1 Transmission networks

Losses in transmission networks represent a relatively small proportion of the energy transported through them. The Rules require that the Regulatory Investment Test for Transmission (RIT-T) be used when a TNSP proposes to make a capital investment having a value of greater than $5 million[8]. The RIT-T imposes a requirement for TNSPs to consider market benefits and the associated

8 Rules clause 5.6.5C(a)(2).

Application Guidelines provides an example on how the incremental losses associated with a transmission investment should be valued[9].

Whilst there is no requirement for TNSPs to consider the cost of losses in other types of investment, this would represent a relatively small proportion of their costs and, as noted above, the loss levels in transmission networks are relatively low. The CDC is therefore not proposing a change to the Rules concerning transmission investments.

3.1.2 Distribution networks

There is currently no requirement in the Rules, for DNSPs to optimise the cost of network losses. Nor is there any requirement for the AER, when assessing the DNSPs' revenue proposals, to ensure that the cost of losses is considered.

The proposed Distribution Planning and Expansion Framework Rule change outlined in section 1.1 above would introduce a requirement for DNSPs to consider the cost of losses for capital investments of greater than $5 million. However, the nature of distribution businesses is that there are a relatively large number of smaller projects and programs of work that together make up the capital and operating expenditures.

Distribution investments include not only the major capital works that are the subject of the proposed Distribution Planning and Expansion Framework Rule Change and the new RIT-D. Substantial expenditure is incurred by DNSPs on matters such as:

- Smaller projects, below the proposed $5 million threshold of the RIT-D;
- The specification of 'standard' conductor sizes;
- The design and location of substations;
- Transformer characteristics, for transformers of all sizes and voltage levels;
- Target equipment utilisation levels; and
- Network operating practices.

The pre-NEM regulatory arrangements, with vertically integrated distribution businesses, provided some incentive for those businesses to minimise their overall energy purchase costs by reducing losses. That is no longer the case in the current regulatory environment.

On 4 July 2011, the Department of Climate Change and Energy Efficiency held a pre-determination seminar in Sydney on revised distribution transformer Minimum Energy Performance Standards (MEPS). At this meeting, anecdotal evidence presented by various parties highlighted a lack of consistency in the approach by DNSPs to the consideration of transformer loss costs. Statements made by participants would indicate that in some jurisdictions DNSPs do not account for the cost of losses. This, in part, is the rationale for distribution transformer MEPS.

With an item of equipment such as a transformer, the cost of electrical losses over the life of the transformer can readily exceed the original purchase price. There is thus considerable scope to minimise overall supply costs by optimising the design of the transformer. The same type of consideration can apply to the selection of conductor sizes and supply voltage levels.

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9 Final - Regulatory investment test for transmission application guidelines, June 2010, pp. 68-69.

As the overall level of losses in distribution networks is significantly greater than transmission networks, the CDC believes that it is appropriate for the cost of losses to be considered in all distribution investments.

3.2 *Incentives applying to Network Service Providers*

The existing Rules establish economic incentives that apply to both DNSPs and TNSPs. These incentives are high-powered and are directed at encouraging them to reduce their capital and operating expenditure.

There is also the potential for a distribution loss incentive through the Efficiency Benefits Sharing Scheme (EBSS) established for DNSPs by the AER, which has not been implemented.

These incentives are described below.

3.2.1 Economic incentives

The existing economic regulatory framework applied to DNSPs has strong incentive properties, designed to enhance the efficiency with which they control their expenditures. The relevant incentives apply to:

- Capital expenditure; and
- Operating expenditure.

The existing economic incentives are described in turn.

Capital expenditure incentive

DNSPs' capital expenditure is subject to what the AER has termed a high-powered regulatory incentive, in which both the return on and return of capital (depreciation) are effectively at stake.

Where the capital allowance is overspent, the asset is rolled into the Regulatory Asset Base (RAB) at its depreciated value at the next regulatory review. The DNSP forfeits the return on and return of capital from the time it is incurred until the assets are rolled into the Regulatory Asset Base (RAB) at the next regulatory review. The timing of the regulatory reset process, which is based on audited financial data, results in the minimum forfeiture of two years of any overspent capital related costs.

This incentive is symmetrical. If the capital allowance is underspent, the DNSP retains the return on and return of capital that were built into its revenue or price allowance. This situation persists until the roll forward at the next regulatory review reduces the RAB and the underspend is recognised.

The incentive property of this arrangement, using typical regulatory cost of capital parameters, is illustrated in Figure 1.

Figure 1 – Capital expenditure incentive

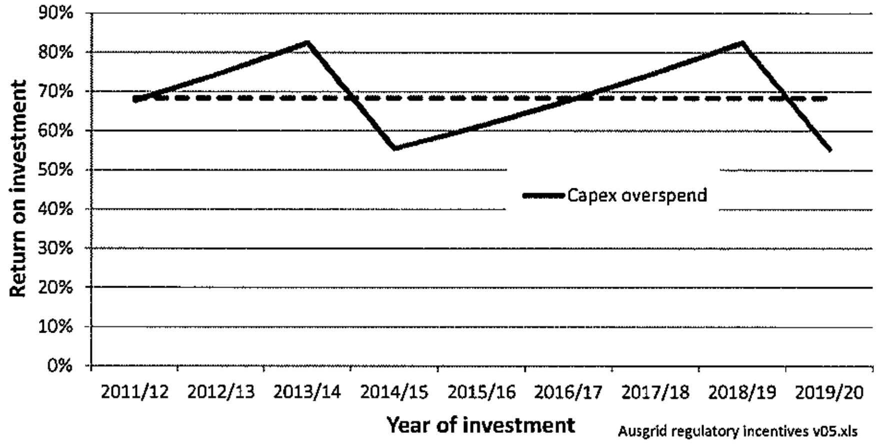

Figure 1 highlights the difference in financial outcome, depending upon the timing of the expenditure vis-à-vis the nest regulatory review, which in this example will take place in mid-2014. The incentive varies between -18% and -38%, and has an average value of -32%.

Operating expenditure incentive

There is also a strong incentive under the regulatory framework, to contain operating expenditure to lower than the regulatory allowance. Where the operating expenditure allowance is overspent, the funds are not reimbursed. Where funds are underspent, the operating allowance is retained until the time of the next regulatory reset. At the reset, the AER reviews the efficiency of operating expenditure and could reasonably be expected to reduce the opex allowance to match the lower level of actual expenditure.

The operating expenditure incentive is thus also strongly related to the timing of expenditure, in relation to the regulatory reset. This was recognised by the AER, and it has developed and applied the Efficiency Benefits Sharing Scheme (EBSS) to DNSPs[10]. The intention of the scheme is to levellise the incentive to reduce operating costs throughout the regulatory control period, thereby mitigating the naturally greater incentive to reduce costs at the commencement of the period than towards the end.

The design of the scheme makes adjustments for the carry-forward of differentials in controllable operating cost, between the allowance in the determination and as-spent amounts[11].

The scheme is symmetric in operation. If it is assumed that a step change in opex made during a regulatory control period is incorporated into the allowance at the next regulatory reset, the incentive profile in Figure 2 results. This illustrates the constant multiplier of 4.7 that applies to opex, regardless of the year in which the change is made. A step increase in opex of $1 M has a total cost of $4.7 M over a period of 5 years.

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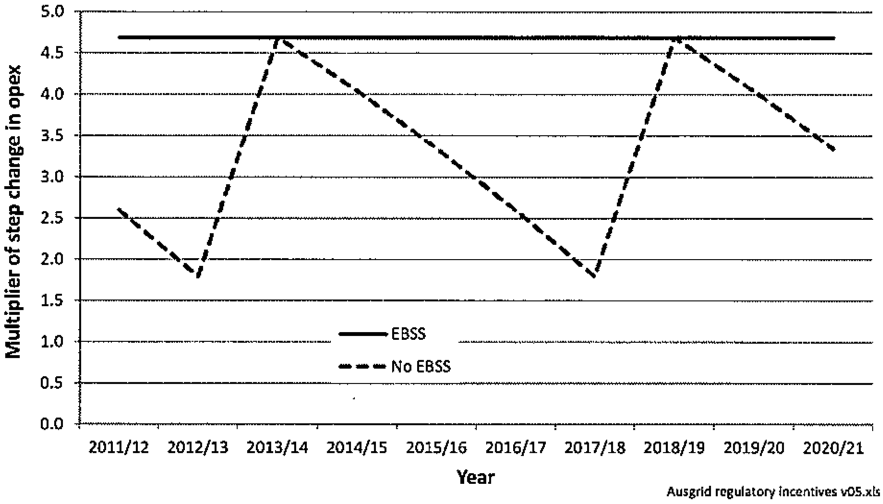
10 AER, Final decision - Electricity distribution network service providers Efficiency benefit sharing scheme, June 2008.

11 AER, Final decision - New South Wales distribution determination 2009-10 to 2013-14, 28 April 2009, p. 248.

Figure 2 – Operating expenditure incentive



3.2.2 Direct loss incentives

Direct controls have been used by regulators to create an incentive for DNSPs to reduce distribution losses. This is generally in the form of a revenue or price cap adjustment, linked to the overall level of losses in the distribution network.

A direct loss reduction incentive was imposed in NSW by the Independent Pricing and Regulatory Tribunal (IPART), in its 1996 distribution determination. The incentive mechanism was an adjustment to the revenue cap based on the annual losses in the distribution network compared with the average of the previous 5 years[12].

In the 1999 distribution determinations, IPART discontinued this loss adjustment mechanism, stating[13]:

> "The Tribunal questions whether adding a coefficient to the revenue stream is the most appropriate method of providing incentives. Setting a coefficient for an incentive mechanism is highly subjective and may lead to inappropriate signals. Therefore, the Tribunal wishes to explore other incentive mechanisms."

In formulating the Efficiency Benefits Sharing Scheme (EBSS) that applies to DNSPs as part of the current regulatory framework, the AER decided not to include a direct incentive on distribution losses. Regarding distribution losses, the AER stated [14]:

> "In its proposed EBSS the AER decided not to apply the scheme to distribution losses. Those stakeholders who responded to this issue were supportive of the AER approach."

With regard to the effectiveness of direct regulatory incentives for DNSPs to reduce losses, the CDC offers the following comment.

12 IPART, Electricity Prices, March 1996, pp. 9, 10.

13 IPART, Regulation of New South Wales Electricity Distribution Networks – Determination and Rules under the National Electricity Code, December 1999, p. 11.

14 Final decision - Electricity distribution network service providers Efficiency benefit sharing scheme, June 2008, p. 14.

The annual electrical loss in a distribution network is determined from the difference between metered inputs and outputs to the network, with adjustment for unmetered loads such as street and traffic lights. The inputs are from the transmission network and connected generators, which are normally interval metered. However, the majority of metering at customers' premises is of the accumulation type and is usually read at three monthly intervals, on a continuous basis.

As a consequence, whilst the input volume can be accurately determined at year end, the output contains a significant volume of accrued energy consumption. It is not until about 5 months after year-end, until most accumulation meters have been read, that the accrual volume is sufficiently small to estimate the losses in the network for the year.

For each accumulation metered customer, energy consumed within the year is estimated from the energy consumption over three months, apportioned between years. This estimate is subject to uncertainty due to variable weather conditions, which affects winter consumption in particular. Higher consumption caused by a cold July would be to some extent smeared into the previous financial year and cause an apparent reduction in distribution losses in that year.

There is therefore significant natural year-on-year variability in the calculated distribution losses (circa 5% of the long term average). Only over an averaging period of say, 5 years, can the overall average losses be established with sufficient confidence to be used to accurately determine distribution loss factors. It follows that:

- Any regulatory incentive based on the most recent years' losses will be subject to significant stochastic variation, which will dwarf any actual initiatives made by the DNSP to reduce losses; and
- A regulatory incentive based on a rolling average (of say, 5 years) would reduce this volatility but react slowly to any loss reduction initiative made by the DNSP. The inherent lag would render this incentive ineffective.

The CDC also echoes IPART's concern regarding subjectivity in determining the value of a loss incentive, leading to the likelihood of inefficient investment outcomes. The CDC therefore believes that direct regulatory incentives are problematic and therefore inappropriate.

3.3 Achieving an economically efficient level of distribution losses

An economically efficient level of losses will occur in distribution networks if DNSPs assign an appropriate value to losses in the analysis of their capital (and operating) investments. That is, if the appropriate analysis and inputs are used, efficient investment outcomes will naturally follow.

The CDC believes that using an appropriate value for the incremental cost of losses in each investment input, where losses are material, will lead to superior outcomes than through the application of a 'blunt' regulatory incentive applied to one overall output.

It is recognised that with many of the investments that DNSPs make, incremental losses are not material. However, where they are, they need to be assigned an appropriate value. As network capital investments typically have useful lives of 40 years or more, a long-run approach to the valuation of losses (ideally covering the same time frame as the investment) is appropriate.

Distribution investments include not only the major capital works that are the subject of the proposed Distribution Planning and Expansion Framework Rule Change and the new RIT-D. This includes expenditures associated with the broad range of activities set out in section 3.1.2.

Whilst certainly a step in the right direction, the MCE's Rule change proposal for the Distribution Network Planning and Expansion Framework does not capture these types of investment decisions. However, an efficient level of distribution losses will only ensue, if DNSPs assign an appropriate cost to losses to each investment where losses are material.

3.4 Valuing losses for DNSP investments

A paper describing an appropriate long-run cost of losses methodology and outcomes accompanies this submission. For different load profiles, this methodology aggregates[15]:

- The long-run incremental cost of generation, based on AEMO's research;
- The long run marginal costs of expanding the upstream distribution and transmission networks to deliver energy to the point at which it is consumed, or lost; and
- The incremental upstream losses to deliver energy to the point in the network at which it is consumed, or lost.

This review has indicated that the cost of electrical losses is much greater than the average market value of energy. Indeed, losses have a long-run value much closer to that of the retail tariff at the point at which the energy is lost in the system. Moreover, as there is now greater clarity concerning the implementation of carbon pricing in Australia, this also needs to be factored into the long-run cost of losses.

The CDC understands that a methodology for valuing losses such as that described above is not in common use by DNSPs.

In view of the broad range of values that could be ascribed to electrical losses by the DNSPs, the CDC considers that guidance should be provided to DNSPs on the way in which the economic value of losses in the network is to be determined. This would parallel the guidance to TNSPs in the Application Guidelines for the RIT-T. Accordingly, the CDC has proposed the following additional sub-clause, for inclusion in the Application Guidelines for the new Regulatory Investment Test for Distribution (RIT-D):

> 5.6.5CA(h)(3A) an appropriate methodology for valuing the long-run costs of *electrical energy losses*;

The CDC considers that this additional guidance would lead to considerably less diversity in the DNSPs' analysis, more robust outcomes and improved overall economic efficiency.

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15 Colebourn H, The cost of losses for future network investment in the new networks regime. Presented to the September 2010 conference of the Electric Energy Society of Australia conference in Sydney in September 2010.

4 Promoting the National Electricity Objective

The National Electricity Objective is as follows[16]:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The basic intent of this proposed Distribution Losses Rule change is to ensure that the cost of distribution losses is factored into operating and capital investment analysis by DNSPs, whenever that cost is material to the investment.

The CDC's proposed amendment of the MCE's Distribution Planning and Expansion Framework Rule change proposal would establish guidance for DNSPs on an appropriate value for the long-run cost of losses, in similar manner to the guidance that has been established for TNSPs.

At present, DNSPs have no requirement in the Rules to consider the cost of electrical losses in their investment analysis. Whilst DNSPs may consider the cost of losses, the economic incentives inherent in the current regulatory framework would encourage them to minimise capital and operating costs, which may often be achieved by developing high-loss solutions.

These incentives would encourage a DNSP to minimise capital and operating costs over the life of the investment, without regard to the cost of losses:

$$Min[NPV(capital\ cost) + NPV(operating\ cost)]$$

For an investment where the marginal change in losses is material, the least overall cost solution to consumers would arise from minimising the following cost:

$$Min[NPV(capital\ cost) + NPV(operating\ cost) + NPV(loss\ cost)]$$

Where losses are material, a high-loss solution will not have the lowest overall cost to consumers, as reduced network costs would be more than offset by higher loss costs.

The appropriate consideration of the log-run cost of electrical losses in distribution investments will lead to improved:

- Efficiency in the capital and operating investments in distribution networks;
- Efficiency in the operation and use of distribution networks; and
- Long-term reductions in the price of electricity supply.

The CDC therefore believes that this proposed Distribution Losses Rule change will contribute to the achievement of the National Electricity Objective, in the interests of electricity consumers.

16 South Australia, National Electricity (South Australia) Act 1996 Version: 1.1.2010, Part 1 – Preliminary.

5 Impacts of the proposed Distribution Losses Rule change

The Distribution Losses Rule change proposal would apply to a large number of individual operating and capital expenditure projects carried out by DNSPs. For each project, the costs and benefits of optimising losses would vary. It is therefore not considered feasible to provide a quantitative estimate of the Rule change proposal.

What follows is a qualitative assessment of the impacts of the Distribution Losses Rule change proposal. The costs and benefits and the parties to which they apply have been considered in the following categories.

Costs:

- Administrative costs of implementing the proposed Rule change;
- Ongoing impact on DNSP capital and operating expenditures;

Benefits:

- Long-term reduction in the cost of electricity supply

These aspects are discussed in the following sections.

5.1 Implementation of the proposed Distribution Loss Rule change

The Proposed Rule change will make a minor modification to the regulatory framework, to require that DNSPs consider the cost of losses in their capital and operating investment forecasts.

DNSP implementation

For very many of the capital and operating project decisions made by DNSPs, the incremental losses due to an investment would be zero or immaterial. There would be no additional administrative burden associated with the planning and forecasting of such projects.

Where a distribution project would have an incremental effect on losses, and where alternative projects with the same objective are being compared, the DNSP will be required to estimate the incremental loss quantity over the life of the project or alternative. This is not expected to be an onerous task.

The DNSP would then and apply a suitable long-run cost to determine the economic effect of incremental losses over the life of the project or alternative. The CDC's proposed addition to the Distribution Planning and Expansion Framework Rule change proposal would require the AER to establish guidance for DNSPs on determining a suitable cost of losses and it is envisaged that a standard cost at a few different levels of the network would apply.

The inclusion of loss costs into the analysis of a project or alternative options, where material, is therefore not expected to impose a material additional administrative cost on DNSPs.

AER implementation

In carrying out a distribution determination, the AER is required to assess the DNSP's forecasts of operating and capital expenditures against:

- The operating and capital expenditure objectives set out in Rules clauses 6.5.6(a) and 6.5.7(a); and

- The forecast DNSP requirements in Rules clauses 6.5.6(b) and 6.5.7(b).

In practice, the AER engages technical consultants to review the expenditure forecasts and advise whether the DNSP's forecast expenditures meet these Rules requirements. In carrying out this task, the consultant reviews a sample of completed and forecast projects, to determine whether the DNSP has appropriately carried out investment analysis.

The Distribution Loss Rule change proposal would modify clauses 6.5.6(b) and 6.5.7(b), to include a requirement for the DNSP to consider the long-run cost of losses, in preparing the operating and capital expenditure forecasts.

From the AER's perspective, there would be no additional administrative burden or cost in assessing DNSP compliance with this additional requirement. The technical consultant would in any case assess a sample of investment analyses and advise whether this additional requirement had been followed by the DNSP.

The CDC's proposed addition to the Distribution Planning and Expansion Framework Rule change proposal, to require the AER to establish guidance for DNSPs on determining a suitable cost of losses does not form part of this proposed Rule change. However, it should be noted that this advice would streamline the processes used by each DNSP to determine the long-run cost of losses.

5.2 Impact on DNSP capital and operating expenditures

The economic incentives that apply to DNSPs have been described in section 3.2.1. These incentives encourage DNSPs to minimise their capital and operating expenditures, without regard to the cost of network losses.

The effect of the proposed Distribution Losses Rule change would be to change the investment framework to minimise the overall costs of supply, including the long-run cost of losses. Where the incremental losses associated with an individual investment project are material, this could potentially result in an increase in the capital or operating cost, if it were at least offset by lower loss costs. For example, in a DNSP's decision to select a transformer for a particular capital project or program of works, minimising the overall costs of supply is likely to result in the selection of a lower loss transformer, at marginally higher capital cost.

The proposed Rule change will thus result in marginal increases in each DNSP's operating and capital costs associated with those individual projects where the cost of losses is material.

5.3 Long-term reduction in the cost of electricity supply

The framework for the development of a DNSP's capital and operating expenditure forecasts would be modified by the Distribution Losses Rule change proposal to include the overall cost of supply. The AER would assess the efficiency of the DNSP's proposed expenditure forecasts against this revised requirement.

As a consequence, although the capital and operating costs of some elements of the forecast are likely to increase marginally, the long-term costs of supply would be minimised. This improved investment efficiency would flow through long-term reductions in the price to consumers.

Appendix – Proposed marked up Rule change

Modification to Rules clause 6.5.6 (operating expenditure objectives for DNSPs)

6.5.6 Forecast operating expenditure

(a) A *building block proposal* must include the total forecast operating expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *operating expenditure objectives*):

(1) meet or manage the expected demand for *standard control services* over that period;

(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(3) maintain the quality, reliability and security of supply of *standard control services*;

(4) maintain the reliability, safety and security of the *distribution system* through the supply of *standard control services*.

(b) The forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* must:

(1) comply with the requirements of any relevant *regulatory information instrument*; and

(1A) pay regard to the cost of *electrical energy losses* in the *distribution system*; and

(2) be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the *Distribution Network Service Provider*; and

(3) include both:

(i) the total of the forecast operating expenditure for the relevant *regulatory control period*; and

(ii) the forecast of the operating expenditure for each *regulatory year* of the relevant *regulatory control period*.

Modification to Rules clause 6.5.6 (capital expenditure objectives for DNSPs)

6.5.7 Forecast capital expenditure

(a) A *building block proposal* must include the total forecast capital expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *capital expenditure objectives*):

(1) meet or manage the expected demand for *standard control services* over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) maintain the quality, reliability and security of supply of *standard control services*;

(4) maintain the reliability, safety and security of the *distribution system* through the supply of *standard control services*.

(b) The forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* must:

(1) comply with the requirements of any relevant *regulatory information instrument*; and

<u>(1A) pay regard to the cost of *electrical energy losses* in the *distribution system*; and</u>

(2) be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the *Distribution Network Service Provider*; and

(3) include both:

(i) the total of the forecast capital expenditure for the relevant *regulatory control period*; and

(ii) the forecast of the capital expenditure for each *regulatory year* of the relevant *regulatory control period*; and

(4) identify any forecast capital expenditure that is for an option that has satisfied the *regulatory test*.

The cost of losses for future network investment in the new networks regime

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Introduction

The supply industry is at a turning point, where the forecast costs of energy generation are expected to increase markedly beyond "traditional" levels and current market prices. The reasons for this are three-fold:

- The prospect of climate change has influenced Government policies to encourage a move to renewable energy sources;
- There is the strong likelihood of some form of carbon price in the near future, which will also increase the costs of energy generation; and
- Networks have been the subject of recent regulatory determinations, that for most have dramatically increased their capital and operating expenditure allowances.

This paper sets out an approach to determining forward-looking long run costs for the three main supply chain components of the cost of losses:

- Energy generation;
- The provision of network capacity; and
- The provision of incremental upstream losses.

The analysis in this report has provided average loss costs by voltage level and is specific to the NSW region of the Australian National Energy Market (NEM). However, it provides a clearindication that a significant change in the cost of losses now needs to be factored into investment analysis across the NEM.

The cost of losses can be a significant input to the planning, design and operational activities of network businesses. Whilst the cost of losses will rarely provide the complete justification for an augmentation project, it can change the relative ranking of alternatives (particularly when comparing augmentation options with different voltages). The cost of losses can also influence the preferred timing of an augmentation project, where moderate load growth permits this.

The cost of losses thus has potentially significant implications for the following types of investment decisions, which are routinely made by transmission and distribution network businesses:

- The choice of economically efficient augmentation options, including the choice of supply voltage level; and
- Lifecycle costs used for equipment specifications, such as optimal underground cable and line conductor sizes and transformer designs, are critically dependent on this input.

Network businesses do not incur the direct cost of losses, which are settled between trading participants in the NEM. Nonetheless, there is a direct requirement for these businesses to factor loss costs into their investment analysis, to support the NEM objective "to promote efficient investment in, and use of, electricity services for the long term interests of consumers of electricity with respect to price …".

The Ministerial Council on Energy (MCE) has directed a review of the National Electricity Rules (the Rules) and regulatory framework on distribution network planning and expansion, including the requirements for network investment. The treatment of loss costs in investment analysis is an important factor in those considerations.

The cost of losses is also a determining factor in establishing the Minimum Energy Performance Standards (MEPS), for appliances and equipment such as distribution transformers. The specification of revised Stage 2 distribution transformer MEPS is currently underway as part of the Australian Governments' Equipment Energy Efficiency Program (E3). The consultation Regulatory Impact Statement (RIS) on revised distribution transformer MEPS is awaited at the time of writing.

Contents

1. Foundations for the analysis of electrical loss costs

Investment in network infrastructure usually involves the installation of additional or replacement equipment having a life span of 30 years or more. It follows that the total ownership cost of the investment must be assessed from the associated capital and operational costs over a commensurate period.

The cost of electrical losses forms a component of virtually every network investment, although for some investments it is not a material component. In addition, some network investments are made to maintain prescriptive network security or reliability criteria. Nevertheless, the consideration of loss costs should accompany every network investment and their detailed assessment should be incorporated, where the loss costs are material.

Long Run Marginal Costs

In economic terms, the Long Run Marginal Cost (LRMC) over the period of investment analysis is the appropriate cost to be applied to losses. In this report, the major components of the cost of losses have been considered on this basis.

In relation to the costs of energy generation, estimates of future generation costs need to incorporate the influence of some externalities which are expected to have potentially significant effects, namely the Mandatory Renewable Energy Target (MRET) requirements and a carbon price, through a mechanism such as the Carbon Pollution Reduction Scheme (CPRS).

Cost basis

The convention used in this report is that all costs have been expressed in 2009-10 Australian dollars. Where source material from other years was used, the cumulative CPI index published by the Australian Bureau of Statistics (ABS) was used to adjust costs[1]. Estimated costs in other currencies were firstly converted to Australian dollars using the average conversion rate applicable to their year of estimation and then indexed to 2009-10[2].

Regional basis

For the purpose of this analysis, the NSW region of the National Energy Market (NEM) has been chosen and indicative loss costs for a metropolitan (EnergyAustralia) and a regional (Country Energy) distributor have been estimated. Despite this scope limitation, the results provide a clear indication of changed conditions that apply across the NEM, albeit with some regional and distributor specific variations.

No-load loss and load loss

The losses that are associated with the operation of electrical equipment need to be considered in two separate categories because of their differing impact on the power system, as follows:

- No-load (or shunt) loss is a relatively constant leakage loss, which is independent of the equipment loading and takes place whenever the equipment is energised; and

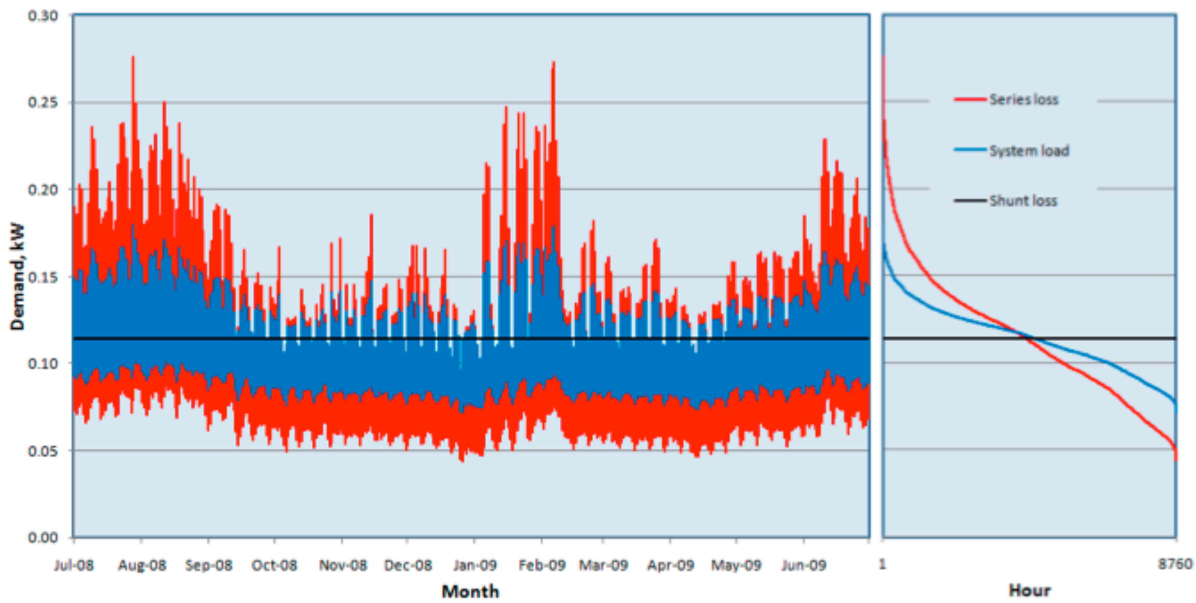
- Load (or series) loss depends upon the electrical load supplied by the equipment. The load losses vary with the square of the load current imposed on the equipment.

[1] Australian Bureau of Statistics, 6401.0 - Consumer Price Index, Australia- Weighted average of eight capital cities, 27 January 2010.

[2] Reserve Bank of Australia, F11 Exchange rates, 9 December 2009.

Figure 1 illustrates the half-hourly demand associated with load and no-load losses, compared with the demand profile of the average system load in the NSW region of the NEM for the year 2008/09[3]. The three load and loss profiles are scaled for a normalised consumption of 1 MWh per annum. The blue trace represents the system load, the constant black trace the no-load loss profile and the red trace the load loss profile. This illustration serves to highlight how these very different load profiles affect the peak period demand, with a constant quantum of delivered energy. The annual load duration curves at right further highlight the comparison.

Figure 1 – Profile of system demand and losses



In the chart at left, which shares the same y axis, the load profile displays the seasonal and weekly variation associated with electricity consumed. At right, the same hourly information is reordered to display the load duration curve associated with the different consumption profiles.

It follows that in evaluating the cost of losses for investment analysis, the consideration and separate costing of their two components, load and no-load losses, is necessary. Their very different consumption profiles and influence on peak demand affect the cost of both energy generation and of network delivery.

Components of the cost of delivered energy

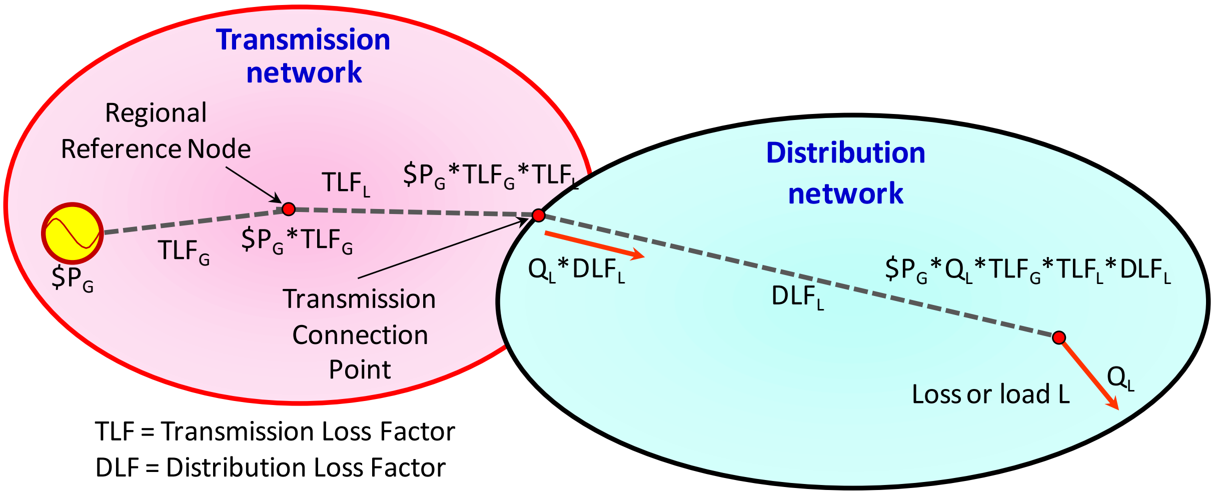
The structure of the Australian NEM and the disaggregated entities in the supply chain are illustrated in Figure 2. In this illustration, the market settlements arrangement for energy delivered to a point in the distribution network is shown.

Losses within the transmission network are accounted for with transmission loss factor adjustments, which apply to the prices at all connection points to the transmission network. These are marginal factors that adjust the regional reference price (RRP). In most, but not all, cases, the price paid to generators is less than the RRP and the price paid by retailers at load connection points is greater than the RRP.

[3] NEM consumption and price data is available from the AEMO web site at http://www.aemo.com.au/data/price_demand.html.

Distribution loss factors act as volume adjustments from the point in the network where load is connected to the relevant transmission connection point. Distribution loss factors are average quantities which increment the load by the losses within that network.

Figure 2 - Market settlements in the NEM



Whilst transmission loss factors act as price multipliers and distribution loss factors act as volume multipliers in the market settlements, the cost outcome of settlements for load supplied to the distribution network is the multiple of all upstream loss factors, the generator price and the volume. Thus for a load Q_L connected in the distribution system:

Generator bid price	$\$P_G$	
Price of energy at market RRN	P_{RRN}	$= \$P_G*TLF_G$
Price of energy purchased from market at transmission connection point	P_{TCP}	$= P_{RRN}*TLF_L$ $= \$P_G*TLF_G*TLF_L$
Volume of energy purchased from market at transmission connection point	Q_{TCP}	$= Q_L*DLF_L$
Cost of energy delivered to distribution system	Cost	$= P_{TCP}*Q_{TCP}$ $= \$P_G* TLF_G*TLF_L* Q_L*DLF_L$

Transmission and distribution costs also need to be added to the cost of energy delivered within the distribution network. The Transmission and Distribution Use of System (TUoS and DUoS) costs are all ultimately recovered from customers.

These elements taken together make up the cost of delivered energy (or of lost energy) and are described in Figure 3.

Figure 3 - Components of the cost of delivered energy

Generation	Energy is delivered to the market from these locations. Generator bids need to cover the fixed and variable costs of energy production, plus transmission costs and transmission losses incurred in delivery to the market.
Transmission network	
Transmission loss	Transmission losses adjust the generator bid price.
Transmission cost (TUoS)	A minor component of transmission cost is levied on generators and recovered through their market bids.
National Energy Market (NEM)	Energy is settled on a half hourly basis in the market at the Regional Reference Node (RRN).
Transmission network	
Transmission loss	Transmission losses adjust the market purchase price at the transmission boundary.
Transmission cost (TUoS)	The major component of transmission cost adds to the cost of delivered energy.
Transmission - Distribution boundary	Wholesale energy is purchased from the market at this interface.
Distribution network	
Distribution loss	Distribution losses adjust the volume of energy that must be purchased from the market.
Distribution cost (DUoS)	Distribution costs add to the cost of delivered energy.

Energy consumed at a point within a distribution network affects each element of the upstream energy supply chain, increasing both:

- The quantum of energy required; and
- The cost of energy delivered to that point.

Each of these component costs is now considered in turn.

2. Energy generation costs

For the purpose of comparison, two sources of generation cost have been considered:

- Wholesale energy market related costs, from 2008/09; and
- Forward looking generation costs, using the most recently available estimates of alternative generation technologies.

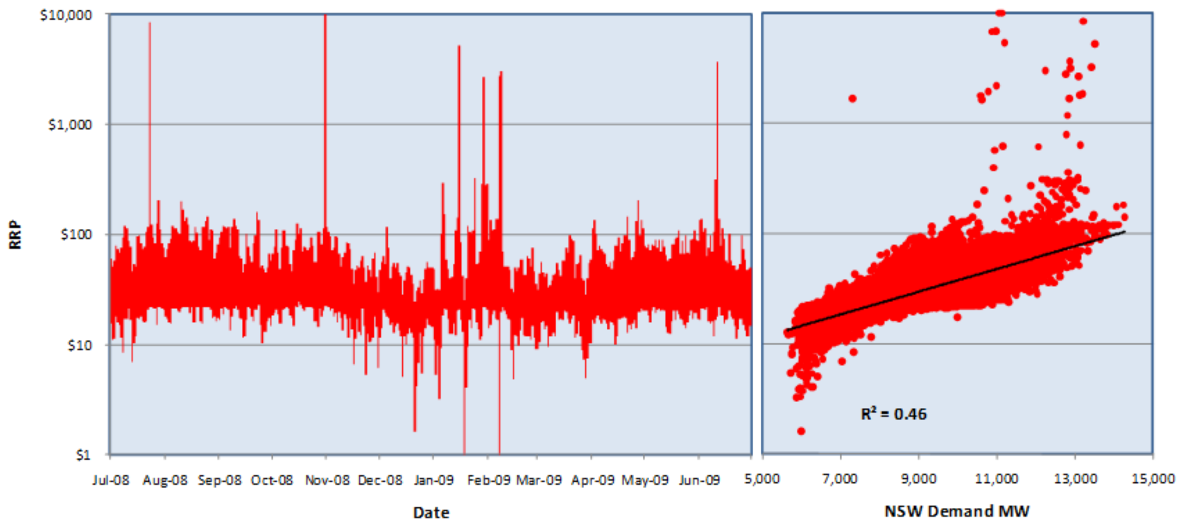
2.1 Wholesale energy market costs

The most recent full year of wholesale market data, for 2008/09, provides the actual cost of losses that would have been incurred in that year, at the level of the RRN. The half-hourly Regional Reference Price (RRP) or pool price varied throughout a great range during the year, from a maximum capped at $10,000, to a minimum of -$105.15.

In Figure 4, the maximum and minimum daily values of the RRP have been shown in the left hand bar chart. Negative prices were excluded to enable a logarithmic vertical scale, necessary to compress extreme pool price excursions.

There is a reasonable correlation between the RRP and the NSW region demand, as evidenced by the R^2 value of the scatter plot at right. Here, an exponential best-fit trajectory appears as a straight line with the logarithmic scale. The two charts have the same vertical scale.

Figure 4 - Pool price and regional demand for NSW, 2008/09



Analysis of the half hourly settlements data for the year to determine the cost of losses is carried out in three ways:

1. A simple average of the RRP. This would correspond with the average wholesale cost of energy supplied to a constant load (or no-load loss);

2. A load weighted average of the RRP, represented by the following formula:

$$P_1 = \frac{\sum_{n=1}^{17,520} RRP_n \bullet D_n}{\sum_{n=1}^{17,520} D_n}$$

   Where:

   RRP_n is the RRP for half hour *n*; and

   D_n is the Regional Demand supplied by the market in half hour *n*.

   The load weighted average price is the wholesale cost of supplying a load with the same profile as the system average; and

3. A load-squared average of the RRP, represented by the following formula:

$$P_2 = \frac{\sum_{n=1}^{17,520} RRP_n \bullet D_n^2}{\sum_{n=1}^{17,520} D_n^2}$$

The average price so calculated is the wholesale cost of supplying a load with the same profile as the load losses incurred in supplying a load with the system average profile (since the load loss is proportional to the square of the load).

These average wholesale costs, indexed to $2009/10, are set out in Table 1.

Table 1 - Wholesale energy costs of supply, 2008/09

Load profile	No-load loss	System load	Load loss
Wholesale cost of supply	$39.80	$43.80	$48.40

The correlation between the RRP and the regional demand may be seen as an increased cost associated with the supply of energy to a more 'peaky' load profile.

2.2 Forecast energy market costs

The wholesale prices of section 2.1 are the outcome of market settlements, in which the generator bids and associated contracts with retailers recover their costs. The cost of energy delivered to the market includes the following components:

- Energy production;
- Transmission network losses; and
- Transmission network charges.

Each of these components is considered in turn, to develop a forecast of future energy costs.

Generation costs

The most recently available forward-looking generation cost information is contained in the Australian Energy Market Operator's (AEMO) 2009 generation cost review[4]. ACIL Tasman was engaged to develop this data for the primary purpose of conducting market simulation studies. These studies were undertaken to identify the requirement for additional transmission infrastructure in the NEM, given projected generation expansion scenarios.

ACIL Tasman developed Short and Long Run generation cost forecasts for a range of future generating technologies, with locational variations for 16 regional zones across the NEM. The costs were estimated over a period extending to 2028-29. In this report, these costs have been summarised as averages over the four zones covering NSW and the ACT. Although there is not a great deal of cost variation after the introduction of the CPRS, a mid-range date of 2019-20 for new generation was chosen for this comparison.

The information in the ACIL Tasman report pertains to those generation technologies that can be dispatched in the market. It thus does not include some forms of renewable generation, notably wind and solar. An alternative recent Australian source of information on those costs is McLennan

[4] ACIL Tasman, Final Report Fuel resource, new entry and generation costs in the NEM Prepared for the Inter-Regional Planning Committee, April 2009.

Magasanik and Associates' (MMA) report prepared for the Australian Geothermal Energy Association[5].

The costs of new technology generation are summarised in Table 2.

Table 2 - LRMC of new generation technologies introduced in 2020

Technology	Capacity factor	LRMC excluding CPRS $/MWh generated	LRMC including CPRS[6] $/MWh generated
CCGT	85%	$57	$74[7]
OCGT	15%[8]	$156	$183[7]
Coal	85%	$48	$77[7]
Geothermal	85%	$78	$78[7]
Advanced coal	85%	$67	$79[7]
Nuclear	85%	$98	$98[7]
Wind	30%[9]	$105	$105[10]
Biomass	85%[11]	$113	$113[10]
Large solar	30%[11]	$268	$268[10]
Small solar photovoltaic	20%[11]	$522	$522[10]
Key: CCGT = Combined cycle gas turbine; OCGT = Open cycle gas turbine; Advanced coal = Ultra-supercritical coal and Integrated gasification combined cycle; Large solar = solar collector or solar thermal; Small solar = rooftop solar photovoltaic.			

It is feasible to simplify this range of future new generating technologies somewhat, for the purposes of the analysis in this report. The existing, committed and proposed generation capacity forecast in the AEMO statement of Opportunities, which covers the period to 2019, was used[12]. The following simplifications have been made:

- AEMO does not anticipate any nuclear or geothermal contribution in NSW by 2019 and these technologies have therefore been excluded;

5 McLennan Magasanik and Associates. Report to AGEA (Australian Geothermal Energy Association) - Comparative Costs of Electricity Generation Technologies, February 2009.

6 Assumes carbon prices as per Treasury's CPRS -5 scenario.

7 ACIL Tasman, April 2009, Table 52 and Table 53.

8 The ACIL Tasman cost estimates have been prepared with a uniform 85% capacity factor. This is not a realistic assumption for the operating regime of this form of generation, which has a relatively high fuel cost. An adjustment has been made to the LRMC to recover the capital component over a more typical capacity factor. Whilst OCGT facilities are often designed for capacity factors of 30%, their utilisation in NSW is more likely to fall in the range of 10 to 15% to meet the NSW requirement for peaking generation, highlighted by the load duration in Figure 5.

9 MMA, February 2009, p.2 (assumed to lie at the lower end of the range of 28% to 43%).

10 MMA, February 2009, Table 3-1.

11 Energy Information Administration - Report #:DOE/EIA-0554(2009) - Assumptions to the Annual Energy Outlook 2009, March 2009, Table 13.2.

12 Australian Energy Market Operator, 2009, Electricity Statement of Opportunities, Chapter 4.

- The cost of energy generated from coal and advanced coal is very similar. The cost of coal has been used;
- Wind, biomass, geothermal and large solar generation sources are unscheduled. Moreover, the anticipated contribution of both biomass and solar is relatively small. They have been therefore been grouped together and their weighted average cost used; and
- Small-scale rooftop solar photovoltaic is the most expensive of the energy generation options and its recently increased penetration has been as a result of subsidies for the installation of units of 1.5 kW or less, Renewable Energy Certificate (REC) entitlements and jurisdictional solar feed-in tariffs[13,14]. This form of energy generation is not settled in the market and has been excluded on the basis that it would be incorporated into AEMO's energy and demand projections by being netted off customer demand and energy.

Transmission network losses for generators

The capacity-based average of AEMO's 2009/10 marginal loss factors for major NSW generators is 0.9659[15]. That is, on average these generators lose approximately 3.5% of revenue derived through market settlements, due to the application of marginal transmission loss factors.

It has been assumed that the majority of new generation technologies are likely to be located at existing generation sites or similarly located sites. The delivered cost of energy to the market would therefore carry this 3.5% mark-up.

Wind generation is most likely to be located in remote locations, with either transmission or high capacity distribution connections to the interconnected network and load centres. For this reason, an additional loss of 5% has been assumed for this form of generation.

Transmission network costs for generators

The existing major generators in NSW pay a small component of Transmission Use of System (TUoS) to TransGrid for their dedicated connection assets[16]. This cost has been averaged over the energy delivered to the grid by power stations, to obtain a $/MWh connection cost[17].

This transmission cost has been assumed to apply to similarly located new generators, again with the exception of wind. In the case of wind generators an additional transmission charge, equivalent to an investment of $20 million in a dedicated transmission connection for each 100 MW of generation was added.

Summary of the forecast cost of energy generation

A summary of the cost of energy delivered to the market RRN for the alternative generation technologies is set out in Table 3.

13 McLennan Magasanik and Associates. Report to Department of Climate Change - Benefits and Costs of the Expanded Renewable Energy Target, January 2009, p.30.

14 KPMG, NEMMCO Ltd - Stage three - Semi-scheduled, Non-scheduled and Exempted Generation, by fuel source in NEM regions 2008-9 to 2028-29 - Final Report, March 2009.

15 NEMMCO (now AEMO), List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year - Version No. 2.0 - Final, 30 April 2009.

16 TransGrid, TransGrid's Transmission Prices - 1 July 2009 to 30 June 2010, 14 May 2009.

17 TransGrid, New South Wales Annual Planning Report, 30 June 2009, Table A3.1, p.78.

Table 3 - Forecast cost of generation delivered to the Regional Reference Node

Technology	Capacity factor	LRMC incl. CPRS $/MWh generated	Loss Cost $/MWh	TUoS $/MWh	Total $/MWh delivered
CCGT	85%	$74	$2.60	$0.30	$77
OCGT	15%	$183	$6.50	$0.30	$190
Coal	85%	$78	$2.70	$0.30	$81
Wind & unscheduled	30%	$105	-[18]	$9.20	$114

The forecast mix of existing and new generation types

In order to forecast the cost of energy supply to loads of different profile, it is necessary to consider the way in which the different energy sources with different costs and capacity factors are likely to be despatched for operation in the NEM. The NSW profile for 2009/09 was used to develop the generator mix. This profile had a maximum half-hourly demand of 14,152 MW. The profile was scaled to 16,850 MW in 2019-20, to match the forecast summer demand growth of 2.1% over the period[19].

The capacity of existing, committed and proposed generation in NSW was taken from AEMO's Statement of Opportunities. This is summarised by generator type, in Table 4[20].

Table 4 - Existing, committed and proposed generation in NSW

Technology	MW, Summer	
	Scheduled and semi-scheduled	Unscheduled
CCGT	1,452	0
Coal	14,865	0
OCGT	3,930	263
Biomass	0	214
Hydro	2,436	190
Wind	2,250	214
Total	24,933	881

Based on the above assumptions, Figure 5 illustrates the likely mix of the types of generation described in section 0, with the addition of the existing hydro stations (principally Snowy). Snowy Hydro has installed capacity of 3,746 MW and annual average generation of 4,500 GWh, which equates to an annual capacity factor of around 14%[21]. Its price was set equal to OCGT as it provides similar economic value to the market.

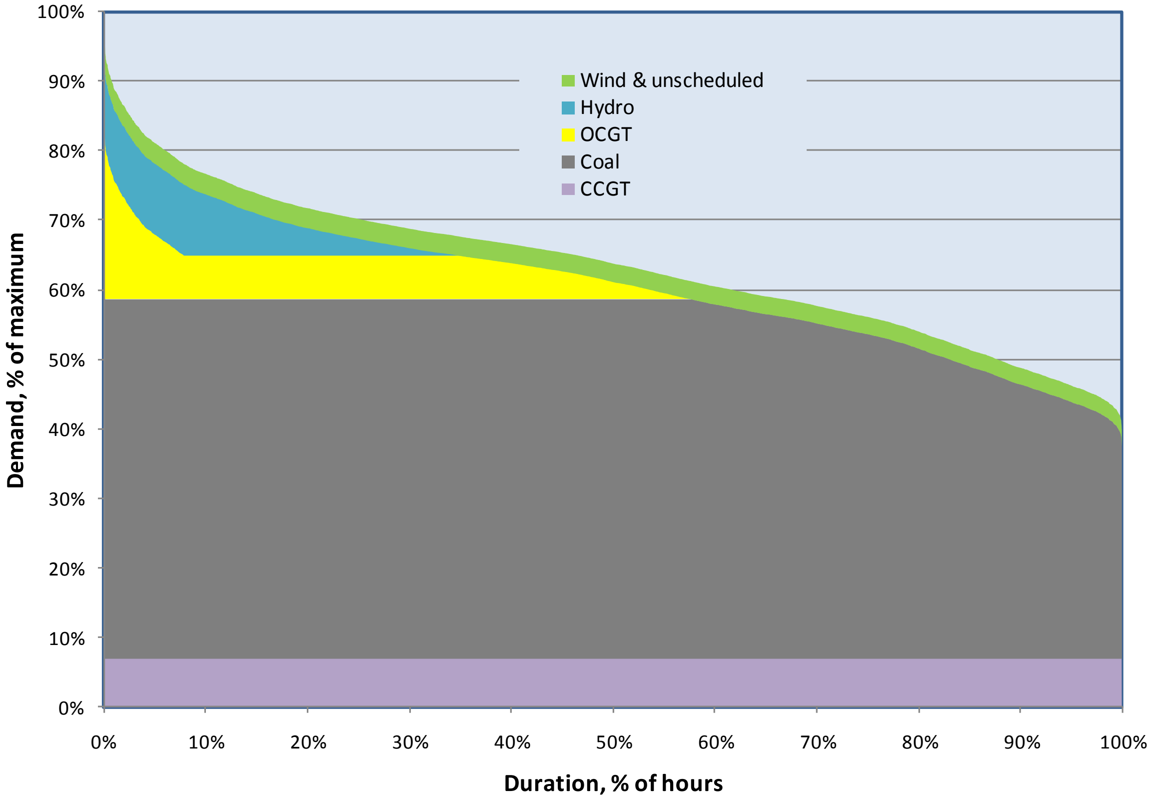
18 The cost of transmission losses is included in the LRMC estimate by MMA.

19 TransGrid, New South Wales Annual Planning Report 2009, Table 3.2, p.79.

20 AEMO 2009 ESoO, Chapter 4, Tables 4.5, 4.6, 4.17 - 4.20, pp.4-10 to 4-38.

21 Intelligent Energy Systems, Insider, 31 March 2006, p.2.

Figure 5 - Forecast mix of existing and new generation by 2020



Wind and unscheduled generation was assumed operate with the peak demand and capacity factor assumed in AEMO's 2009 Statement of Opportunities. The coincident reduction in peak demand is 540 MW, and the reduction in energy 1500 GWh, which equates to an annual capacity factor of 31.7%[22].

2.3 Summary of forecast energy market costs

The incidence of costs arising from the assumed generation mix in section 0, for loads of different profile, is set out in Table 5.

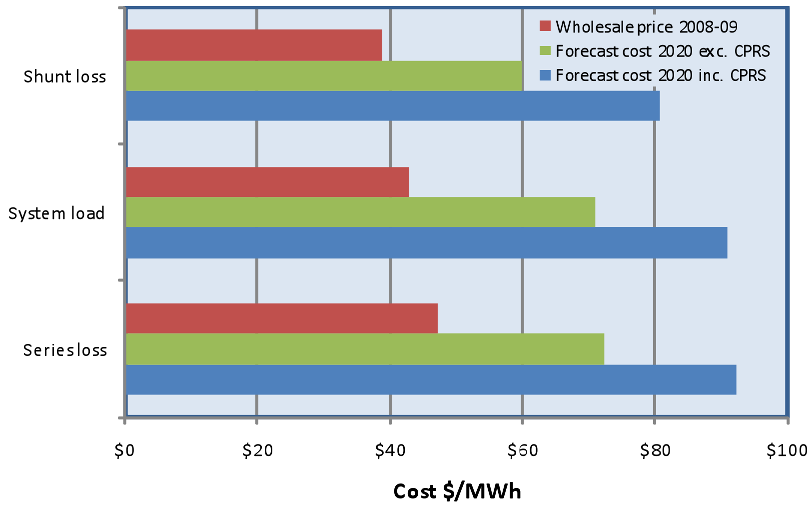
Table 5 - Long Run costs of energy supply, 2020

Load profile	No-load loss	System load	Load loss
Forecast cost of supply	$80.80	$90.90	$92.40

These forecast costs are compared with the 2008/09 wholesale energy costs in Figure 6.

22 AEMO 2009 ESoO, Chapter 3, pp.3-24, 3-28.

Figure 6 - Comparison of 2008/09 wholesale energy market costs with forecast costs



The forecast costs of energy supply are significantly greater than 2008/09 wholesale supply costs set out in section 2.1. Effectively, the market is currently clearing at a price that is closer to the forecast 2020 Short Run Marginal Cost (SRMC) of energy supply without CPRS, of approximately $25/MWh for the equivalent generation mix.

The influence of the load profile on generation costs remains apparent.

3. Energy delivery via the transmission and distribution networks

The incremental capacity costs and upstream energy losses associated with losses incurred within different levels of the network are described in this section.

3.1 Incremental network capacity costs

Network businesses are highly asset intensive and the associated asset related costs constitute the majority of their revenue requirement. It follows that the main determinant of network cost is the provision of capacity in the network, requiring its augmentation. Losses incurred in the network add marginally to the capacity required to supply load and need to be costed on an equivalent basis to load requirements.

Network assets have very long lives, generally in excess of 30 years, and often, lengthy construction times. Network augmentation is thus extremely 'lumpy' as there are large, high cost investments at irregular intervals. The costing of network services using a LRMC approach is appropriate to this situation. Asset costs are recovered through the return on and return of capital over the life of the asset and the cost of future development of network infrastructure can be reflected both in prices for the use of the network and in the valuing the cost of losses.

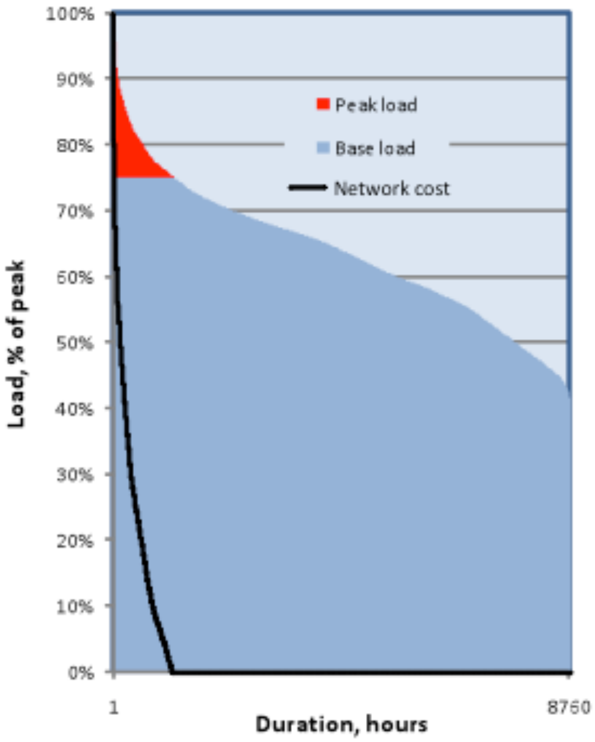
The first step in this process is to evaluate the LRMC of the network. The Net Present Value (NPV) of the future capacity augmentation investments and associated operating cost are spread over the associated increment in either demand or energy. Over a period of several years, for EnergyAustralia this calculation has resulted in an LRMC of approximately 80% of the average network revenue. In its most Pricing Proposal, EnergyAustralia revised its approach and estimated marginal costs, based on kVA, of between 51% and 142% for the major tariff classes[23]. The weighted average of almost 120% represents an increase on earlier years, caused by higher levels of capital spending in the 2009-14 regulatory control period. Equivalent information was not disclosed in Country Energy's 2009-10 Annual Network Pricing Report.

[23] EnergyAustralia, Network Pricing Proposal (Revised), May 2009, Table 5, p.47.

A cost allocation aligned with the requirement to invest in the network will provide an appropriate signal of the cost of providing capacity to meet peak period demand. The approach described in this paper is a modification of a cost allocation process termed the Method of Intercepts[24,25].

In this infrastructure based cost allocation, the network LRMC has been conservatively assumed to remain at 80% of the average network price. This cost was allocated to the upper 75% of system loading, since the network is generally augmented to provide capacity for loads above this level. The LRMC component of network cost is thereby allocated to the peak period loads. This concept is illustrated in Figure 7.

Figure 7 - Network marginal cost allocation



In Figure 7, the allocated network cost may be seen to escalate rapidly to its peak value, as loads exceed the 75% threshold.

This network cost profile was applied to different loading profiles, to yield the network marginal cost allocation factors shown in Table 6.

Table 6 - Network marginal cost allocation factors

No-load loss	System load	Load Loss
75%	80%	131%

The network marginal cost allocation factors of Table 6 were applied to 2009-10 transmission and distribution prices, to determine the cost applicable to losses.

24 Armstead, C H Allocating Fixed Costs, Energy International, December 1969.

25 Colebourn H and Amos C, Pricing Signals for a Network Business, 8th Institution of Engineering and Technology conference on Advances in Power System Control, Operation and Maintenance, Hong Kong, November 2009.

Incremental network loss allocation

The chart at right in Figure 1 illustrates very different profiles associated with no-load (shunt) losses, the system load and load (series) losses. Loss factors at both transmission and distribution are normally determined for the system load profile. These factors need to be adjusted in order to validly apply to loads with a different profile.

Table 7 sets out the adjustment factors applied to loss factors to accommodate loads of different profile.

Table 7 - Network loss allocation factors

No-load loss	System load	Load Loss
63%	100%	153%

3.2 Transmission network costs

Transmission Network Service Providers (TNSPs) recover their revenue via Transmission Use of System (TUoS) charges to DNSPs. These costs apportioned to two NSW distributors are shown in Table 8[26]. The allocated revenue for the distributors was converted into an average price using the energy forecast contained in the AER's determination[27].

Table 8 - Transmission network costs, $/MWh

Distributor	No-load loss	System load	Load Loss
Metropolitan	$6.60	$7.10	$11.60
Regional	$12.30	$13.20	$21.60

The cost allocation factors of Table 6 were used to formulate Table 8.

Transmission network losses

Transmission network losses are accommodated in the market by marginal loss factors used to adjust the price at the RRN to the point of connection to the transmission network. The marginal loss factors differ for each transmission connection point. Weighted averages of the transmission loss factors of two NSW distributors (EnergyAustralia and Country Energy) are shown in Table 9.

Table 9 - Transmission network losses

Distributor	No-load loss	System load	Load Loss
Metropolitan	0.8%	1.3%	2.0%
Regional	1.4%	2.2%	3.3%

The loss allocation factors of Table 7 were used to determine the percentages in Table 9.

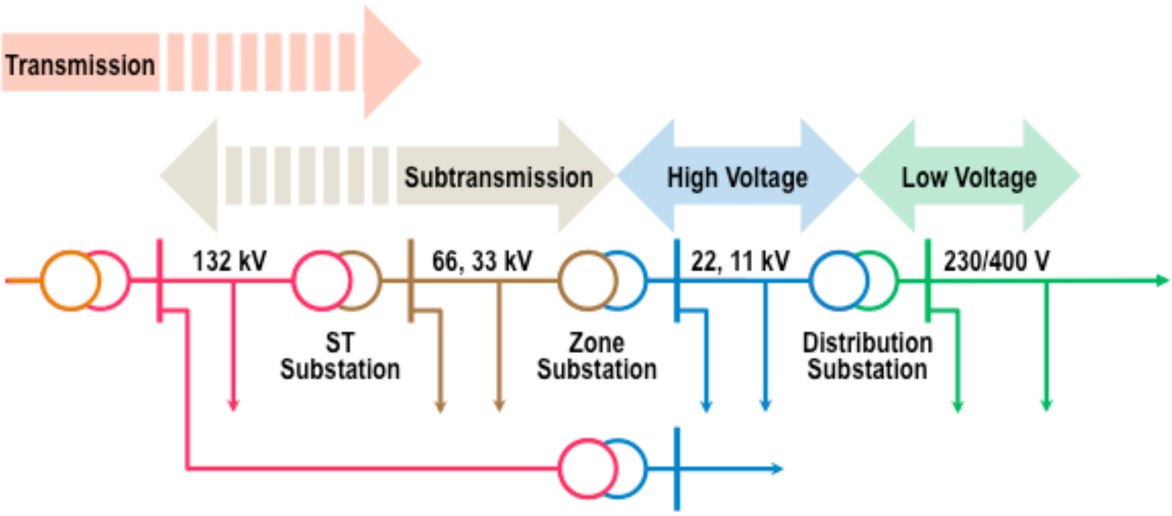
26 AER, Final decision TransGrid transmission determination 2009–10 to 2013–14, 28 April 2009, Table 9.5, p.122.

27 AER, Final decision New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, Table 16.24, p.321, Table 6.5, p.87, Table 6.3, p.85.

3.3 Distribution network costs

The typical structure of a distribution network and the levels of supply are shown in Figure 8. There can be overlap between assets of 66 kV or higher voltage, which are defined in the Rules as transmission if their function includes the support of the higher voltage transmission network.

Figure 8 - Structure of the distribution network



Customers are connected at all levels of the network, with larger customers at higher voltage levels and the great majority of small customers receiving supply at low voltage. The costs associated with the distribution network are assigned to cost pools for the classes of assets involved and allocated to downstream customers, generally in accordance with their utilisation of the asset cost pool.

The generic structure of Figure 8 does not highlight very significant differences between the structure of distribution networks that serve metropolitan and regional areas:

- Metropolitan networks have much greater load densities, shorter route lengths, a significant proportion of larger customers at higher voltage levels and often a greater proportion of underground construction; whereas
- Regional networks are characterised by low load densities, long overhead route lengths and outside regional centres, predominantly high voltage reticulation.

Distribution network pricing has become subject to a National compliance regime under the Rules, requiring the disclosure of information concerning matters such as the pricing allocation process, price levels and changes. The NSW pricing proposals were the first to be subjected to this regime, in 2009. The published information in the EnergyAustralia and Country Energy pricing proposals[28,29] was supplemented with other published information to derive the distribution network costs at different levels of the network[30,31].

28 EnergyAustralia, Network Pricing Proposal (Revised), May 2009, Table 12, p.59.

29 Country Energy, Annual network prices report 1 July 2009 – 30 June 2010, Figure 6, p.10.

30 AER, Final decision New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, Table 6.5, p.87.

31 EnergyAustralia, Distribution Loss Factor Calculation Methodology Paper, March 2009, Table 4, p.12.

The associated distribution network LRMC values are set out in Table 10 for each level of the network. These are cumulative - supply to a low voltage load would incur each upstream cost component.

Table 10 - Distribution network costs, $/MWh

Distributor	No-load loss	System load	Load Loss
Metropolitan			
Subtransmission	$14.30	$15.30	$25.00
High Voltage	$2.30	$2.50	$4.00
Low Voltage	$30.00	$32.20	$52.70
Total	$46.60	$50.00	$81.80
Regional			
Subtransmission	$6.00	$6.40	$10.50
High Voltage	$32.60	$35.00	$57.20
Low Voltage	$34.30	$36.70	$60.10
Total	$72.80	$78.10	$128.00

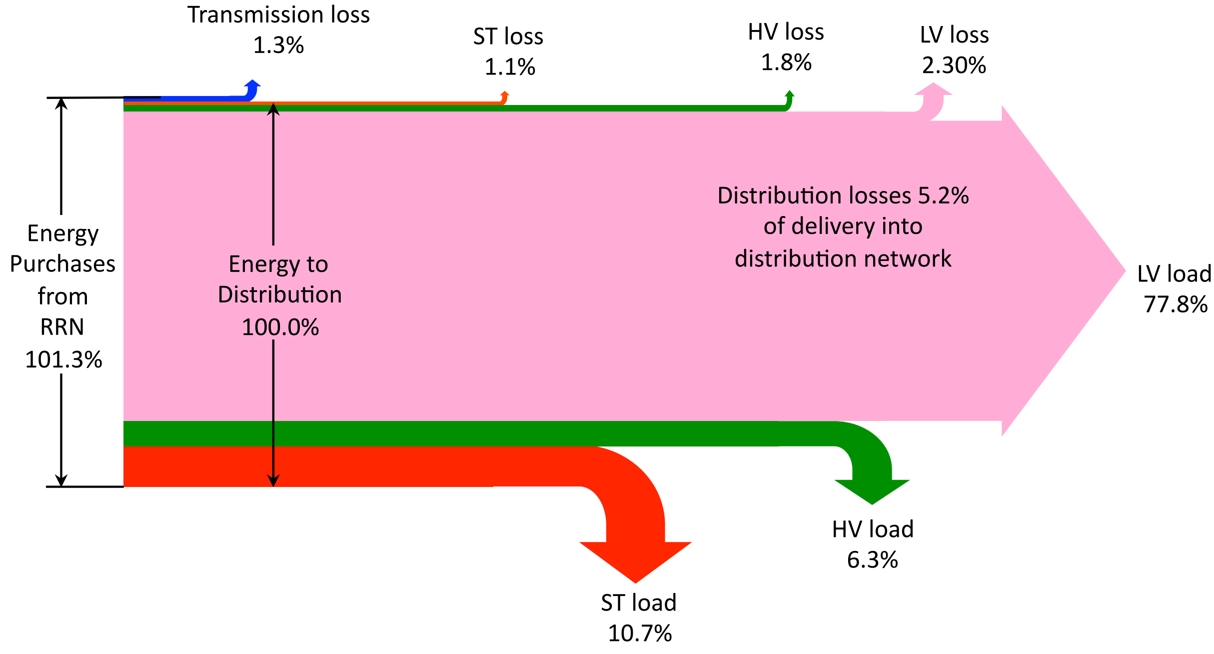
The cost allocation factors of Table 6 were also used in formulating Table 10.

4. Distribution network losses

Distribution losses take place at each of the levels of the network indicated in Figure 8. Those losses include the no-load and load losses in network elements and a small proportion of 'non-technical losses' to account for metering discrepancies and theft.

Distribution losses are also subject to a regulatory regime involving disclosure of the processes employed and approval of the resultant loss factors used for market settlements. Only one of these disclosure documents, EnergyAustralia's[31], provides a loss balance table, which has been used to develop the 'leaky pipe' diagram in Figure 9.

Figure 9 - Distribution losses 'leaky pipe' diagram for metropolitan distributor



In Figure 9, the relative proportions of both losses and load supplied at different levels of the network can be seen. A similar diagram for a regional distributor may be expected to reveal higher overall losses at transmission, subtransmission and high voltage distribution levels (totalling 10% or more). In addition, the lower energy density normally implies a smaller proportion of energy consumed at higher voltage levels, by larger customers.

The approved 2009-10 distribution loss factors used in market settlements by NEMMCO[32] were used to construct the table of loss factors in Table 11 for EnergyAustralia and Country Energy.

The percentages apply as a volume adjustment to the quantities settled at the market RRN.

Table 11 - Distribution losses

Distributor	No-load loss	System load	Load Loss
Metropolitan			
Subtransmission	1.1%	1.7%	2.5%
High Voltage	0.9%	1.5%	2.3%
Low Voltage	2.3%	3.5%	5.4%
Total		6.7%	
Regional			
Subtransmission	1.8%	2.8%	4.3%
High Voltage	0.7%	1.1%	1.6%
Low Voltage	4.0%	6.4%	9.8%
Total		10.25%	

The loss allocation factors of Table 7 were used to determine the percentages in Table 11.

32 AEMO, Distribution Loss Factors for the 2009/10 Financial Year - Version No: 4, effective August 2009, Table C5, p.14, Table C6, p.15.

5. Cost of losses within networks

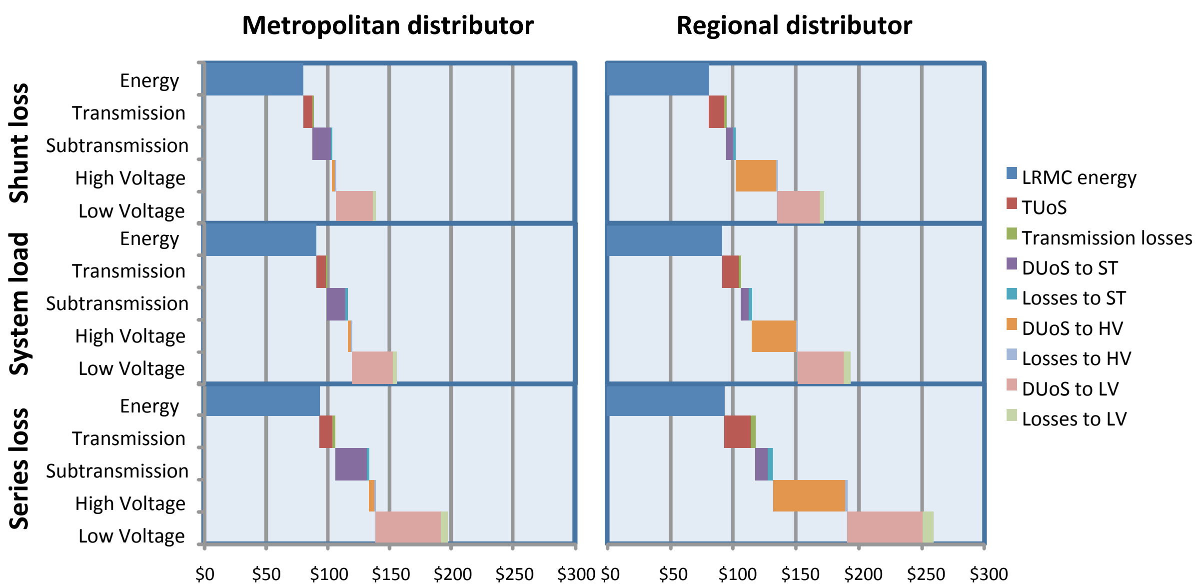
The elements described in sections 2 and 3 have been combined to yield the LRMC of supplying loads of different profile at different levels within the network. The outcome is shown in Table 12.

Table 12 - Cost of losses within networks

Distributor	No-load loss	System load	Load Loss
Market price	\$38.90	\$42.80	\$47.30
Generation LRMC	\$80.80	\$90.90	\$92.40
Metropolitan LRMC			
Transmission connection point	\$88.10	\$99.10	\$106.00
Subtransmission	\$103.00	\$116.00	\$133.00
High Voltage	\$107.00	\$120.00	\$138.00
Low Voltage	\$139.00	\$155.00	\$196.00
Regional LRMC			
Transmission connection point	\$94.40	\$106.00	\$117.00
Subtransmission	\$102.00	\$115.00	\$131.00
High Voltage	\$135.00	\$151.00	\$190.00
Low Voltage	\$172.00	\$193.00	\$259.00

The cost of losses components at different levels in the network are also illustrated in Figure 10.

Figure 10 - Cost of losses within networks



6. Concluding remarks

The foregoing analysis of the cost of losses follows very significant recent increases in the cost of two of their major components. The cost estimates include the necessary distinction between no-load and load losses.

6.1 Movement in the cost of losses

A similarly structured estimate of the long run cost of losses in 2005 yielded the costs set out in Table 13, for the low voltage level of EnergyAustralia's network.[33]

Table 13 - Movement in the cost of losses

Review	Date	No-load loss	System load	Load Loss
2005 analysis	July 2005	$82	$90	$127
… CPI adjustment	December 2009	$94	$103	$145
2010 analysis	December 2009	$139	$155	$196
Increase		48%	51%	35%

The analysis described in this report confirms that there has been a very significant increase in the value that should be attributed to losses in network investment analysis. This difference can be attributed to two influences:

- An increase in the cost of energy generated by new technologies, in which previously uneconomic forms of generation have become competitive due to the presence of the CPRS and RET; and
- Significant increases in network costs, arising principally from increased levels of capital expenditure to augment network capacity levels to match increased demand growth.

6.2 Distribution transformer MEPS

The cost of losses is the determining factor in establishing the MEPS for distribution transformers. The specification of distribution transformer energy performance requirements is currently underway as part of the Australian Governments' Equipment Energy Efficiency Program (E3). The consultation RIS is currently awaited.

It is recommended that in establishing the Stage 2 MEPS for distribution transformers, consideration needs to be given to:

- The significant increase in the cost of losses in establishing the efficiency levels; and
- A revised testing approach, which places greater weighting on the higher cost of load losses, in recognition of the greater cost of their provision.

6.3 Regulatory arrangements for network businesses

Network businesses do not purchase energy to make up losses from the market and there is currently no direct regulatory incentive scheme for distribution businesses to minimise their system losses.

It is apparent from the various examples appended to this report that there is a need for distribution businesses in particular to factor the cost of losses into their investment decision-making in a number

[33] Colebourn H, Cost of losses for network investment appraisal, Electric Energy Society of Australia Conference, 18 November 2005.

of different ways. Whilst no sub-optimal investment decisions were identified, the cost of losses was material in relation to a number of those decisions and if ignored could potentially lead to uneconomic development.

One solution that has been proposed to provide network businesses with an incentive to minimise network losses is to make them responsible for purchasing the energy losses in their networks from the market. This, however, has a number of significant drawbacks:

- As the analysis in this report has demonstrated, the cost of losses purchased from the market is substantially less than the long run cost that needs to be factored into the economic analysis of investment in assets with a service life of 30 years or more;
- For distribution businesses, the magnitude of system losses is significant, quite often larger than the energy consumption of their largest customer; and
- The purchase of lost energy would involve network businesses in market trading arrangements, which is at odds with the current intentional separation of their activities from trading; and
- That involvement in energy trading would introduce a significant level of risk exposure for which network businesses have not been structured or are currently financed.

The existing market arrangements for both transmission and distribution businesses do not provide them with a financial incentive to optimise the cost of lost energy. Rather, the market objective is promulgated through the Regulatory Investment Test.

The Regulatory Investment Test for Transmission (RIT-T) requires transmission businesses to analyse the market benefits associated with investments. To the extent that the market simulation used by TNSPs factors in the future cost of generation, as AEMO's does, an appropriate value would be placed on the cost of losses.

The Rules concerning distribution network planning and expansion are the subject of current review by the AEMC, at the direction of the MCE. A significant aspect of the new arrangements will be the review of the equivalent Regulatory Investment Test for Distribution (RIT-D). The policy intent has been established the AEMC and the associated RIT-D and Application Guidelines will be finalised by mid 2010.

Because of the relative significance of distribution losses and the attendant costs, it is apparent that the following elements need to be factored into the regulatory arrangements for distributors, to avoid a continuation of sub-optimal investment incentives:

- The long run cost of losses in distribution networks needs to be established on a uniform basis across the NEM, allowing for regional variation;
- AEMO is clearly the organisation best equipped to determine the cost of losses at the transmission connection level, using the same future generation costs as this report;
- Each distributor should be required to estimate the average cost of losses at applicable levels within its network, for use in investment analysis;
- Each distributor should be required to demonstrate that an appropriate value has been ascribed to the cost of losses in its equipment specification and purchasing decisions;
- The RIT-D should require DNSPs to carry out a simplified screening test for each network investment, to determine whether the cost of losses would have a material impact on the outcome;
- The investment appraisal for large augmentations should use individually calculated, rather than averaged loss costs;

- There is a need for a general regulatory incentive (equivalent to the STPIS) to provide appropriate funding levels for relatively small investments such as power factor correction and loss reduction in rural areas.

7. Acknowledgement

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