16 November 2016

Dear Mr Chris Pattas
General Manager, Networks
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Dear Sir,

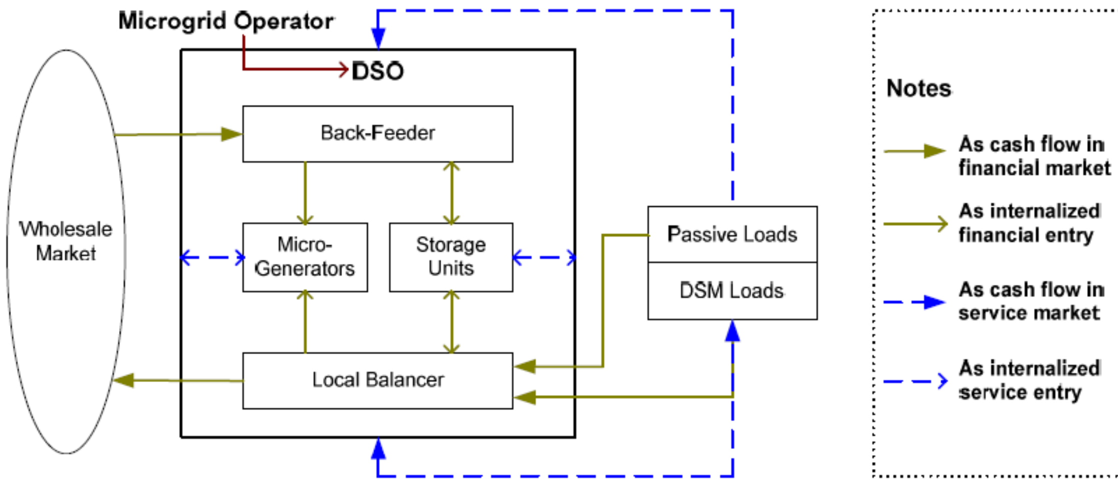
<u>Response to Electricity Distribution Ring-fencing guideline - Exposure draft</u>

This letter is a submission in response to AER's *Electricity Distribution Ring-fencing guideline - Exposure draft November 2016*. The Notice reads "Interested stakeholders are invited to make submissions on critical issues that will affect the Guideline's operability”. Our theme; <u>*micro is superb, time to batten down hatch*</u>.

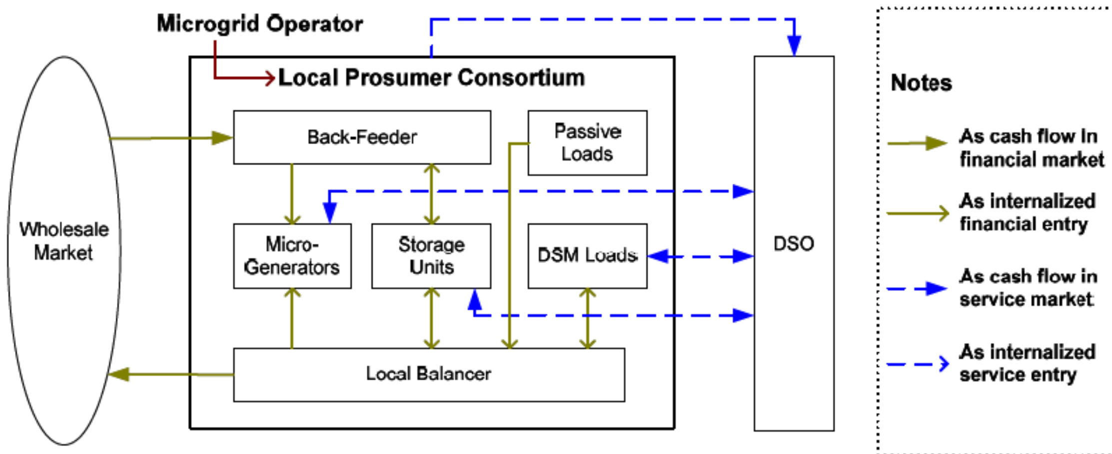
With Steel Energy Technologies Pty Ltd being a private entity, it competes for energy services and investment in network and customer services primarily. Partial-contingency electricity resilience means stand-alone operation trimmed to facilities critical for community disaster / emergency response plus tendrils of common low voltage circuit to surrounding properties. Our proposal for a fringe-of-grid microgrid precinct is to place a whole township “behind-the-meter” from a perspective of its incumbent distribution network service provider (DNSP). Here Community Resilience Microgrid is defined to be Solar PV (200kW to 4MW) and Hybrid Energy Storage – see *clause 1.2 Clarification of the Microgrids Concept* in *DG3&DG4. Report on the technical, social, economic, and environmental benefits provided by Microgrids on power system operation*; 30 Dec 2009 Final.

Our submission to exposure draft of proposed Electricity Distribution Ring-fencing Guideline takes the form of two types of changes:-

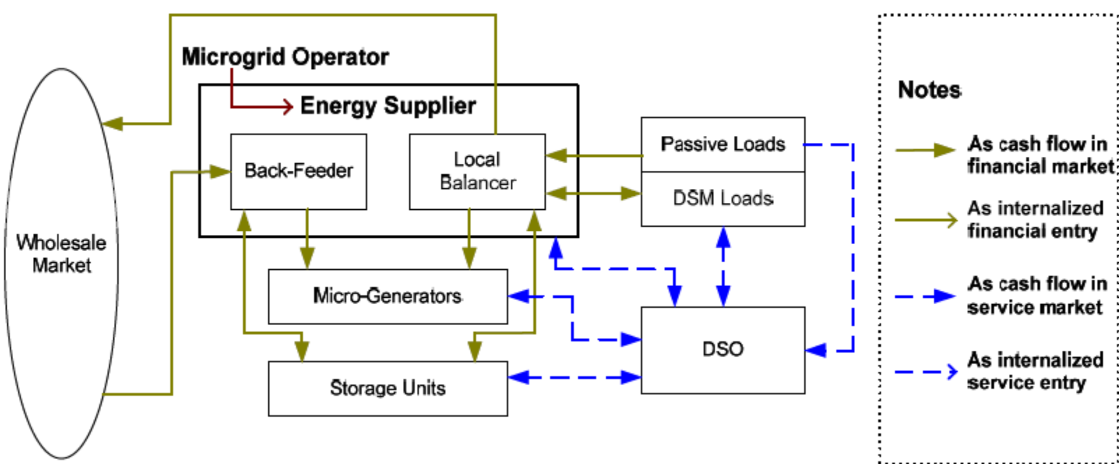
1) Changes needed arising from skewing of Electricity Distribution Ring-fencing Guideline by metropolitan DNSP so as to render regional reforms impractical.
2) Ownership models for Microgrids are comprehensively studied in European jurisdiction; see *DH3. Business Cases for Microgrids Final Report;* Dec 2009.
    a) Changes aimed at “Plug-n-Play” entry for Community Resilience Microgrid under Prosumer Consortium Microgrid Model – see diagram next page.
    b) Microgrid Workshop Q&A rephrased from NEM Workshop for Wind Generation at AUSWEA Conference, in Adelaide 23-25 July 2002.



The DSO Monopoly Microgrid Model



The Prosumer Consortium Microgrid Model



The Free Market Microgrid Model

Electricity Distribution Ring-fencing Guideline – Exposure Draft Comments

1.4 Definitions – regional office: It's impossible to correlate this term with any electrical service in *Electricity distribution network service providers, Annual benchmarking report.* **route line length** means the distances over which DNSP delivers electricity to their customers. To provide their customers with access to National Electricity Market electricity, DNSP has to transport electricity from TNSP to its customers' premises. **office** (i.e. TNSP connection) that has less than 100,000 people living within a route line length of 50 kilometre diameter.

National Electricity Market structure has RETAILERS as customer-facing, <u>not</u> DNSP as customers have to phone DNSP contact centre about outages etc. Property portfolio optimisation of DNSP is ring-fencing offset-cost opportunity for DNSP to relocate out of prime inner-property locations to near substations with employee vehicles transitioning to Electric Vehicles (even if not with auto-pilot).

1.4 Definitions – corporate services: general administration, accounting, payroll, human resources, legal, or communication services**.** "scarce" is a lavish term for competition of communication services into regional and their remoter areas. Sky Muster satellite services or equivalent is 1 of 9 canvased for metropolis in *IoT and the Future of Networked Energy; A Platform for Enhanced Energy Cloud Applications.* Tyranny of distance costs for communication services will render impractical as it's similar to getting easements through national forests or across world heritage areas. An information technology support service conveys implication DNSP exports its culture and values surreptitiously. Relevant clauses are 3.1(d)ii., 4.2.1.(b)i.(c), 4.2.2.(b)i.(c).

"waiver of the obligations" – We have in existence two competing Guideline obligations. One has been prepared for **Prevention of cross subsidies Legal separation** in clause 3.1. The second has been prepared for **Functional Separation Obligation to not discriminate** in clause 4.1. There is asymmetrical opening for **waiver of the obligations** clause 3.1 yes, clause 4.1 no. However, there is a fundamental imbalance in context of **regional office** where clause 3.1 no, clause 4.1 yes, provides greater practical value to wafer-thin reform flexibility.

"appropriately" - it's used seven instances yet one of those weasel words that's devoid of meaning without context e.g. of values, ethics, legality, culture, science, etc. Relevant clauses are 1.1.1, 3.2.1(a), 5.3.2.(b)iii., 6.1.

4.2.2(c) Staff sharing other benefits – The guideline obligation prepared by AER does not prevent DNSP, down the track, from proceeding to disadvantage against the other party by inducing through non-financial other benefits (legal or otherwise if there was anything of this kind out there now). Legal accounting practices are key element in assuring that to the best of both parties knowledge there are no 'other benefits' owing apart from monies to any staff so shared.

7.1 Transitional Arrangements – Don't synchronise with North America financial year, synchronise with Australian financial year and accelerate. Therefore, 7.1.(a) – 1 July 2017 and 7.1(b) – 6 months.

Electricity Distribution Ring-fencing Guideline – Ownership Model

Clause 3.1 Legal separation is hostile to pragmatism relevant to application of Community Resilience Microgrids and *IoT and the Future of Networked Energy; A Platform for Enhanced Energy Cloud Applications.* Prosumer Consortium Microgrid Model encapsulates the geographical topology of delivering electricity to regional and remote customers where there are considerable **route line length** distance then customer clusters in township, village or similar.

DH3. Business Cases for Microgrids Final Report clarifies as follows:- A prosumer consortium Microgrid is most likely to be found in regions with high retail electricity price or high Micro-Source financial support levels (and both conditions are very likely to occur simultaneously). In this case, single or multiple consumer(s) will purchase and operate Micro-Source units to minimize electricity bill or maximize sales revenue from Micro-Source export (if export tariff is high). This type of Microgrid may find considerable barriers set by DSO, as by nature the consortium tends to minimize the use of distribution grid (which leads to a reduction of UoS revenue) and may neglect all network constraints (i.e., hosting capacity) during design of the Microgrid. DSO can only passively influence the operation of a prosumer consortium Microgrid via imposing requirements and charges upon the Micro-Source owners, but will not be able to benefit from the local trading process.

Hence, partial-contingency electricity resilience was proposed under references F and G to provide <u>regulated</u> outcome via controlled usage of distribution grid in competition with nanogrids (e.g. residential behind-the-meter solar PV). **Prevention of cross subsidies Legal separation in clause 3.1.** needs a use case for Prosumer Consortium Microgrid Model that is fit-for-purpose of Community Resilience Microgrid and which has no waiver of the obligations. Return-On-Investment for developer/s of Community Resilience Microgrid is impractical unless spread across multiple deployments with low red-tape costs.

Electricity Distribution Ring-fencing Guideline – Microgrid Workshop Q&A

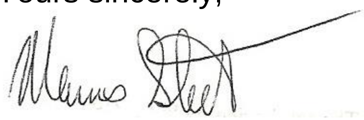
> “Those who cannot remember the past are condemned to repeat it.”

Concerning Winston Churchill’s best remark (reference H) on aforementioned quote Santayana wrote (in The Life of Reason, 1905), a Wind Generation Workshop occurred at AUSWEA Conference, in Adelaide 23-25 July 2002 with twelve workshop questions designed to resolve Central Dispatch, Ancillary Services, Plant and Network Capability, Regulatory Issues thereby averting a power system incident like South Australia Blackout in September 28, 2016.

Since 2030 is a similar duration hence, questions prepared by Ian Arnott from NEM Workshop for Wind Generation at AUSWEA Conference, in Adelaide 23-25 July 2002 are rephrased in references J and K for Microgrid and particularly, Community Resilience Microgrids. It should be noted that functions and duties of NEMMCO in 2002 correspond to AEMO in 2016. Reference L is also provided to accelerate obtaining the views of different stakeholders on key issues.

I would be pleased to discuss this comment at your convenience. Should you wish to discuss this submission, please do not hesitate to contact undersigned.

Yours sincerely,



Marcus DW Steel
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References – sent separately for publication:

A. *DG3&DG4. Report on the technical, social, economic, and environmental benefits provided by Microgrids on power system operation;* 30 Dec 2009 Final. STREP project funded by the EC under 6FP, SES6-019864.

B. *DH3. Business Cases for Microgrids Final Report;* Dec 2009. STREP project funded by the EC under 6FP, SES6-019864.

C. *DF1. Report on field tests for interconnected mode;* January 2010 Final. STREP project funded by the EC under 6FP, SES6-019864.

D. *DG1. Definition of future Microgrid scenarios and performance indices;* November 30th 2008 Final. STREP project funded by the EC under 6FP, SES6-019864.

E. *Electricity distribution network service providers, Annual benchmarking report*; November 2014. Australian Energy Regulator.

F. https://www.aer.gov.au/system/files/Steel%20Wave%20Power%20-%20Submission%20on%20Tasmanian%20electricity%20distribution%20Framework%20and%20approach%20-%2017%20Mar%202015.pdf .

G. https://www.aer.gov.au/system/files/Steel%20Wave%20Power%20-%20Submission%20to%20framework%20and%20approach%20preliminary%20positions%20paper%20-%2015%20May%202015.pdf

H. "When the situation was manageable it was neglected, and now that it is thoroughly out of hand we apply too late the remedies which then might have effected a cure. There is nothing new in the story. It is as old as the sibylline books. It falls into that long, dismal catalogue of the fruitlessness of experience and the confirmed unteachability of mankind. Want of foresight, unwillingness to act when action would be simple and effective, lack of clear thinking, confusion of counsel until the emergency comes, until self-preservation strikes its jarring gong–these are the features which constitute the endless repetition of history." —House of Commons, 2 May 1935, after the Stresa Conference, in which Britain, France and Italy agreed—futilely—to maintain the independence of Austria. (My book* page 490).

Appendices – attached for publication:

I. Redlined version of Electricity Distribution Ring-fencing guideline - Exposure draft
J. MICROGRID WORKSHOP QUESTIONS - iaa 12 July 2002 / revised mdws 14 November 2016
K. MICROGRID WORKSHOP ANSWERS - mdws 16 November 2016
L. AUSWEA CONFERENCE ADELAIDE 23-25 JULY 2002, NATIONAL ELECTRICITY MARKET WORKSHOP, iaa 12 July 2002
M. Planning for Reactive Power Needs of Tasmania, Transend Networks Pty Ltd, October 2002
N. "*Power Factor Correction - The Easiest, Biggest, Green Initiative*" presented at the Energy NSW 2009 – Managing the Winds of Change: Conference & Trade Exhibition in Sydney, 29th to 30th October 2009.

References – not for publication:

O. *IoT and the Future of Networked Energy; A Platform for Enhanced Energy Cloud Applications, Services, and Business Models*. Published 4Q 2016. Navigant Consulting, Inc.
P. "*Convergence of Frequence and Contingency Schemes with Grid SCADA - Island Perspectives*", presented at 23rd Pacific Power Association Conference 2014
Q. "*Using IEC 61850 GOOSE in Wide-Area Solar-Energy Storage to Speed-up Power Quality Smoothing*" presented at Australasian Universities Power Engineering Conference 2016

DRAFT
Ring-Fencing Guideline
Electricity Distribution

November 2016

EXPOSURE DRAFT – WITH REDLINES (APPENDIX I)

AUSTRALIAN ENERGY REGULATOR

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Melbourne Vic 3001

Tel: 1300 585 165
Email: AERInquiry@aer.gov.au
AER Reference: 46484 - D16/109178

Contents

1 Nature and authority

1.1 Application of this guideline

1.1.1 Background and summary

This Electricity Distribution Ring-fencing Guideline (**Guideline**) is made under clause 6.17.2 of the National Electricity Rules (**NER**).

Under clause 6.17.1 of the **NER**, this **Guideline** is binding on all **Distribution Network Service Providers** (**DNSP**s). For the avoidance of doubt, any references in this **guideline** to **transmission services** do not bind **Transmission Network Service Providers** who are not also **DNSP**s.

The objective of this **Guideline** is to:

- promote the **National Electricity Objective** by providing for the accounting and functional separation of the provision of **direct control services** by **DNSP**s from the provision of **other services** by them, or by their **affiliated entities**.
- promote competition in the provision of **electricity services**.

This **Guideline** imposes obligations on **DNSP**s targeted at, among other things:

- cross-subsidisation, with provisions that aim to prevent a **DNSP** from providing **other services** that could be cross-subsidised by its **distribution services**; and
- discrimination, with provisions that aim to:
  - prevent a **DNSP** conferring a competitive advantage on **affiliated entities** which might provide **other distribution services** and / or which provide **other electricity services**; and
  - ensure a **DNSP** keeps information it acquires or generates confidential, and handles that information ethically and appropriately.

1.1.2 Commencement

This **Guideline** commences on 1 December 2016.

1.2 Confidentiality

The **AER** will assess confidentiality claims by **DNSP**s arising under this **Guideline** in accordance with the **Distribution Confidentiality Guidelines**, the **Competition and Consumer Act 2010** and the National Electricity Law (**NEL**).

1.3 Interpretation

In this **Guideline**, unless the contrary intention appears:

- a term in bold type that is expressly defined in clause 1.4 of this **Guideline** has the meaning set out in that clause.
- a term in bold type that is not expressly defined in clause 1.4 of this **Guideline** has the same meaning it has in the **NEL** or the **NER**.
- For the purposes of the application of this **Guideline** in the Northern Territory, the reference to 'national electricity system' in s 7 of the **NEL** must be taken to mean a reference to a 'local electricity system' or to all 'local electricity systems', as the case requires.
- The words 'shall' and 'must' indicate mandatory requirements.
- The singular includes the plural, and vice versa.
- A reference to any legislation, legislative instrument or other instrument is a reference to that legislation or instrument as in force from time to time.
- Explanations in this **Guideline** about why certain information is required are provided for guidance only. They do not limit in any way the **AER**'s objectives, functions or powers.

1.4 Definitions

In this **Guideline**:

- **affiliated entity**, in relation to a DNSP, means a **legal entity**:

  (a) which is a direct or indirect shareholder in the **DNSP** or otherwise has a direct or indirect legal or equitable interest in the **DNSP**;

  (b) in which the **DNSP** is a direct or indirect shareholder or otherwise has a direct or indirect legal or equitable interest;

  (c) in which a **legal entity** referred to in paragraph (a) or (b) is a direct or indirect shareholder or otherwise has a direct or indirect legal or equitable interest.

  and includes, in clauses 4.1 and 4.3 of this **Guideline**, the part of the **DNSP** that provides **Other Distribution Services** and / or **Other Electricity Services**.

- **electricity information** means information about electricity networks, electricity customers or **electricity services**, excluding:

  (a) aggregated financial information;

  (b) other service performance information;

  that does not relate to an identifiable customer or class of customer.

- **existing service** means a type of service that the DNSP was providing on 1 December 2016.
- **information register** means the register established and maintained by a **DNSP** under clause 4.3.5.
- **law** means any law, rule, regulation or other legal obligation (however described and whether statutory or otherwise).

- **legal entity** means a natural person, a body corporate (including a statutory corporation or public authority), a partnership, or a trustee of a trust.
- **NEL** means, for the purposes of the application of this **Guideline** in a **participating jurisdiction**, the National Electricity Law set out in the schedule to the *National Electricity (South Australia) Act 1996* (SA), as applied by the participating jurisdiction and subject to any modification made to the National Electricity Law by that jurisdiction.
- **NER** means, for the purposes of the application of this **Guideline** in a **participating jurisdiction**, the rules called the National Electricity Rules made under Part 7 of the National Electricity Law, subject to any modification made to the National Electricity Rules by that jurisdiction.
- **non-distribution services** means:

  (a) **transmission services**; and

  (b) **other services**.
- **office** means:

  (a) a building;

  (b) an entire floor of a building; or

  (c) a part of a building that has separate and secure access requirements such that **staff** from elsewhere in the building do not have unescorted access to it.
- **officer** means a director or company secretary of the **legal entity**, and any other person:

  (a) who makes, or participates in making, decisions that affect the whole, or a substantial part, of the business of the **legal entity**; or

  (b) who has the capacity to affect significantly the **legal entity's** financial standing;
- **other distribution services** means **distribution services** other than **direct control services**.

  [**Note**: this includes **negotiated distribution services** and **distribution services** that are not classified.]
- **other electricity services** means services for the supply of electricity or that are necessary or incidental to the supply of electricity, other than:

  (a) **transmission services**; or

  (b) **distribution services**.
- **other services** means services other than:

  (a) **transmission services**; or

  (b) **distribution services**.
- **regional office** means an **office** that has less than ~~50~~100,000 people living within a ~~100~~route line length of 50 kilometre ~~radius of it~~diameter.

- **route line length** means the distances over which **DNSP** delivers electricity to their customers. To provide their customers with access to National Electricity Market electricity, **DNSP** has to transport electricity from **TNSP** to its customers' premises.
- **staff**, of an entity (such as a DNSP), includes:
  (a) employees of the entity;
  (b) direct or indirect contractors to the entity (whether the contractors are individuals or corporate or other entities);
  (c) employees of direct or indirect contractors to the entity; and
  (d) individuals (including secondees) otherwise made available to the entity by another party.
- **staff position,** in relation means a position within the organisational staffing structure of a DNSP, or an affiliated entity, that involves the performance of particular roles, functions or duties.

1.5 Process for revisions

The **AER** may amend or replace this **Guideline** from time to time to meet changing needs, in accordance with clause 6.17.2 of the **NER** and the **distribution consultation procedures**.

2 Relationship with other regulatory instruments

This **Guideline** should be read in conjunction with:

(a) The decision in the **AER**'s **distribution determination** on the classification of the **distribution services** to be provided by a **DNSP** in a **regulatory control period**, in accordance with clauses 6.2 and 6.12.1(1) of the **NER**;

(b) Clause 6.15 of the **NER**, the **Cost Allocation Guidelines** and the **AER**-approved **Cost Allocation Method** (**CAM**);

(c) Clause 6.4.4 of the **NER** and the **Shared Asset Guideline**;

(d) A **regulatory information instrument** served on a **DNSP** by the **AER,** or made by the **AER,** under section 28F of the **NEL**.

Together, these instruments achieve the desired ring-fencing outcomes in the long term interest of consumers.

The **AER**'s service classification decisions determine the nature of the economic regulation, if any, applicable to a **DNSP**'s **distribution services**. The classification of a **distribution service** (for example, as a **direct control service** or as a **negotiated distribution service**) affects the application of obligations in clauses 3 and 4 of this **Guideline**. For the purposes of this **Guideline**, distribution services that are not classified are categorised as **other distribution services**.

The **Cost Allocation Guideline** and a **DNSP**'s **CAM** relate to the allocation and attribution of its costs between its **distribution services**. They complement the obligations in clause 3.2.2 of this **Guideline**, which relate to the allocation and attribution of a **DNSP**'s costs between **distribution services** and **non-distribution services**.

The **Shared Asset Guideline** enables the adjustment of a **DNSP's** revenues that it can recover from its **standard control services** where the assets used to provide those services were acquired in order to provide **standard control services** but are then subsequently used to also provide **other distribution services** or **other services**. The shared asset mechanism therefore modifies the effect of the **CAM**.

A **regulatory information instrument** can require a **DNSP** to provide information to the **AER** and to have this information certified and audited, subject to the requirements of the **NEL**. This can include information that is subject to ring-fencing obligations under this **Guideline**.

3 Prevention of cross subsidies

3.1 Legal separation

(a) A **DNSP** must be a **legal entity**.

(b) Subject to this clause 3.1, a **DNSP** may provide **distribution services** and **transmission services**, but must not provide **other services**.

(c) This clause 3.1 does not prevent:

i. an **affiliated entity** of a **DNSP** from providing **other services**;

ii. a **DNSP** and a **Transmission Network Service Provider** from being the same legal entity;

(d) This clause 3.1 does not prevent a **DNSP**:

i. granting another **legal entity** the non-exclusive right to use assets of the **DNSP** in providing **other distribution services** or **other services,** where those assets are also used by the DNSP to provide **distribution services** or **other services** but doing so does not materially prejudice the provision of **direct control services** by the **DNSP**;

ii. providing corporate services (such as general administration, accounting, payroll, human resources, legal, or ~~information technology support~~communication services) to an affiliated entity of the **DNSP**;

iii. providing **staff**, and / or **offices** to an **affiliated entity** where doing so is not prohibited by clause 4.2 (including by reason of a waiver granted by the AER in respect of clause 4.2);

iv. providing **electricity information** to another party where doing so is not prohibited by clause 4.3;

v. otherwise providing assistance to another **DNSP** in response to an event (such as an emergency) that is beyond the other **DNSP**'s reasonable control;

vi. providing any **other services** authorised in accordance with the waiver process set out in clause 5 of this **Guideline**.

as long as the **DNSP** complies with clause 3.2 in relation to those arrangements.

(e) A **DNSP** ~~can~~cannot apply for a waiver of the obligations set out in this clause 3.1.

3.2 Establish and maintain accounts

3.2.1 Separate accounts

(a) A **DNSP** must establish and maintain legally appropriate internal accounting procedures to ensure that it can demonstrate the extent and nature of transactions between the **DNSP** and its **affiliated entities**.

[Note: The **AER** may include a requirement in a **regulatory information instrument** for a **DNSP** to:

i. provide its internal accounting procedures to the **AER**;

ii. report on transactions between the **DNSP** and its **affiliated entities**.]

(b) A **DNSP** cannot apply for a waiver of the obligations set out in this clause 3.2.1.

3.2.2 Cost allocation and attribution

(a) A **DNSP** must allocate or attribute costs to **distribution services** in a manner that is consistent with the **Cost Allocation Principles** and its approved **CAM**, as if the **Cost Allocation Principles** and **CAM** otherwise applied to the allocation and attribution of costs between **distribution services** and **non-distribution services**.

(b) A **DNSP** must only allocate or attribute costs to **distribution services** in accordance with clause 3.2.2(a), and must not allocate or attribute other costs to the **distribution services** it provides.

(c) A **DNSP** must establish, maintain and keep records that demonstrate how it meets the obligations in clauses 3.2.2(a) and 3.2.2(b).

[Note: A **regulatory information instrument** may include a requirement that a **DNSP** provide those records to the **AER** established, maintained and kept in accordance with clause 3.2.2(a) and (b) and / or otherwise demonstrate to the **AER** how it meets those obligations.

(d) A **DNSP** cannot apply for a waiver of the obligations set out in this clause 3.2.2.

4 Functional Separation

4.1 Obligation to not discriminate

(a) For the purposes of this clause 4.1:

i. an **affiliated entity** includes a customer, or potential customer, of the **affiliated entity**;

ii. a competitor of an **affiliated entity** includes a customer, or potential customer, of the competitor of the **affiliated entity**;

iii. dealing, or offering to deal, includes dealing or offering to deal in relation to the provision of goods or services, or the grant of rights, by the DNSP or to the DNSP.

(b) A **DNSP** must not discriminate (either directly or indirectly) between an **affiliated entity** and a competitor (including a potential new competitor) of the **affiliated entity** in connection with the provision of:

i. **direct control services** by the **DNSP** (whether to itself or to any other party); and / or

ii. **other distribution services** or **other electricity services** by any other party.

(c) Without limiting its scope, clause 4.1(a) requires a **DNSP** to:

i. deal or offer to deal with an **affiliated entity** as if the **affiliated entity** is not connected with the **DNSP** rather than being an **affiliated entity** of the **DNSP**;

ii. in like circumstances, deal or offer to deal with an **affiliated entity** and a competitor of the **affiliated entity** on substantially the same terms and conditions;

iii. in like circumstances, provide substantially the same quality, reliability and timeliness of service to an **affiliated entity** and a competitor of the **affiliated entity**;

iv. not disclose to an **affiliated entity** information the **DNSP** has obtained through its dealings with a competitor of the **affiliated entity** where the disclosure would, or would be likely to, provide an advantage to the **affiliated entity**;

(d) A **DNSP** ~~cannot~~can apply for a waiver of the obligations set out in this clause 4.1.

4.2 Offices, staff, branding and promotions

4.2.1 Physical separation/co-location

(a) Subject to this clause 4.2.1, in providing **direct control services**, a **DNSP** must use **offices** that are separate from:

i. any **office** from which it provides **other distribution services** or **other electricity services**; and

ii. any **office** from which an **affiliated entity** provides **other distribution services** or **other electricity services**.

(b) Clause 4.2.1(a) does not apply in respect of:

i. office accommodation for **staff** who, in the course of their duties:

a. do not have access to **electricity information**;

b. have access to **electricity information** but do not have, in performing the roles, functions or duties of their **staff position**, any opportunity to use that **electricity information** to engage in conduct that is contrary to the **DNSP's** obligations under clause 4.1; or

c. only have access to **electricity information** to the extent necessary to perform services that are not **electricity services** (such as general administration, accounting, payroll, human resources, legal, or ~~information technology support~~communication services).

ii. providing assistance to another **DNSP** in response to an event (such as an emergency) that is beyond the other **DNSP**'s reasonable control;

iii. **regional offices,** except to the extent that this exemption has been revoked under clause 5.6;

iv. any arrangements authorised in accordance with the waiver process set out in clause 5of this **Guideline**.

4.2.2 Staff sharing

(a) Subject to this clause 4.2.2, a **DNSP** must ensure that its **staff** involved in the provision or marketing of **direct control services** are not also involved in:

i. the provision or marketing of **other distribution services** or **other electricity services** by the **DNSP**; or

ii. the provision or marketing of **other distribution services** or **other electricity services** by an **affiliated entity**.

(b) Clause 4.2.2(a) does not apply in respect of:

i. a member of **staff** who, in the course of their duties:

a. does not have access to **electricity information**;

b. has access to **electricity information** but does not have, in performing the roles, functions or duties of their **staff position**, any opportunity to use that **electricity information** to engage in conduct that is contrary to the **DNSP's** obligations under clause 4.1; or

c. only has access to **electricity information** to the extent necessary to perform services that are not **electricity services** (such as general administration, accounting, payroll, human resources, legal, or ~~information technology support~~communication services);

ii. providing assistance to another **DNSP** in response to an event (such as an emergency) that is beyond the other **DNSP**'s reasonable control;

iii. staff located at **regional offices,** except to the extent that this exemption has been revoked under clause 5.6;

iv. any arrangements authorised in accordance with the waiver process set out in clause 5 of this **Guideline**.

(c) The incentives and other benefits (financial~~ or otherwise~~) a **DNSP** provides to its **staff** must not give its **staff** an incentive to act in manner that is contrary to the **DNSP**'s obligations under this **guideline.**

(d) Clause 4.2.2(a) does not apply to a member of the **staff** of a **DNSP** where the member of **staff** is an **officer** of both the **DNSP** and an **affiliated entity**.

4.2.3 Branding and cross-promotion

A DNSP:

(a) must use independent and separate branding for its **direct control services** from;

i. the branding that it uses for its **other distribution services** and / or **other electricity services**;

ii the branding of an **affiliated entity**;

such that a reasonable person would not infer from the branding that the **DNSP** and the **affiliated entity** are related, or that the DNSP is providing both **direct control services** and services that are not **direct control services**.

(b) must not advertise or promote its **direct control services** and its services that are not **direct control services** together (including by way of cross-advertisement or cross-promotion).

(c) must not advertise or promote services provided by an **affiliated entity**.

4.2.4 Office and staff registers

A **DNSP** must establish, maintain and keep a written register that identifies:

(a) the classes of offices to which it has not applied clause 4.2.1(a) by reason of clause 4.2.1(b)(i);

(b) the **staff positions** to which it has not applied clause 4.2.2(a) by reason of clauses 4.2.2(b)(i) or 4.2.2(d), including a description of the roles, functions and duties of each **staff position**.

and must make the register publicly available on its website.

4.2.5 Waiver

A **DNSP** can apply for a waiver of the obligations set out in this clause 4.2.

4.3 Information access and disclosure

4.3.1 Meaning of confidential information

For the purposes of this clause 4.3, '**confidential information'** means **electricity information**, acquired or generated by a **DNSP** in connection with its provision of **direct control services**, that is not already publicly available, and includes **electricity information**:

(a) that the **DNSP** derives from that information; or

(b) provided to the DNSP by or in relation to a customer or prospective customer of **direct control services**;

[Note: aggregated financial information, or other service performance information, that does not relate to an identifiable customer, or class of customer, is excluded from the definition of **confidential information**.]

4.3.2 Protection of confidential information

Subject to this clause 4.3, a **DNSP** must:

(a) keep **confidential information** confidential; and

(b) only use **confidential information** for the purpose for which it was acquired or generated.

4.3.3 Disclosure of information

A **DNSP** must not disclose **confidential information** to any person, including an **affiliated entity**, unless:

(a) the **DNSP** has first obtained the explicit informed consent of the relevant customer, prospective customer, to whom the **confidential information** relates;

(b) the disclosure is required by, or for the purpose of complying with any **law**,

(c) the disclosure is necessary to enable the **DNSP** to provide its **distribution services,** its **transmission services** or its **other services,** (including by acquiring services from other parties);

(d) the **DNSP** complies with clause 4.3.4 in relation to that **confidential information**.

4.3.4 Sharing of information

(a) Subject to clauses 4.3.4(b) and 4.3.4(c), where a **DNSP** acquires or generates **electricity information** in connection with providing **direct control services**, and shares that information (including information derived from that information) with an **affiliated entity**, it must provide access to that information (including the derived information) to third parties on an equal basis.

(b) A **DNSP** is only required to provide information to a third party where:

ii. the third party has requested that it be included on the **information register** in respect of that information; and

iii. the third party is competing, or is seeking to compete, with the **DNSP** or an **affiliated entity** of the **DNSP** in relation to **distribution services** or **other electricity services**.

(c) A **DNSP** is not required to provide information to a third party where the **DNSP** has disclosed the information to an **affiliated entity** in the circumstances set out in clauses 4.3.3(a) to (c).

(d) Without limiting clause 4.3.4(a), a **DNSP** must establish an information sharing protocol that sets how and when it will make the information referred to in clause 4.3.4(a) available to third parties, and must make that protocol publicly available.

(e) Where a **DNSP** discloses information referred to clause 4.3.4(a) to any other party (including an **affiliated entity**) it must do so on terms and conditions that require the other party to comply with this clause 4.3 in relation to that information.

4.3.5 Information register

(a) A DNSP must establish, maintain and keep a written register of all other parties (including **affiliated entities**) who request access to information identified in clause 4.3.4(a).

(b) A third party may request that the **DNSP** include it on the **information register** in relation to some or all of the information that the **DNSP** is required to provide under clause 4.3.4, and the **DNSP** must comply with that request.

4.3.6 No waiver

A **DNSP** cannot apply for a waiver of the obligations set out in this clause 4.3.

4.4 Service providers

A **DNSP** must ensure that any provider of services to the **DNSP** does not engage in conduct which, if the **DNSP** engaged in the conduct itself, would be contrary to the **DNSP**'s obligations under clause 4 of this **Guideline**.

5 Waivers

5.1 Granting a waiver

The **AER** will not grant a waiver of an obligation under this **Guideline** other than in accordance with this clause 5.

5.2 DNSP's application for a waiver

A **DNSP** may apply in writing to the **AER** for a waiver of its obligations under clauses 3.1 and 4.2 of this **Guideline** for itself, or for itself and one or more other **DNSP**s who are **affiliated entities** of the **DNSP**. An application for a waiver must contain all information and materials necessary to support the **DNSP**'s application, including:

(a) the obligation in respect of which the **DNSP** is seeking a waiver;

(b) the reasons why the **DNSP** is seeking the waiver;

(c) details of the service**,** or services**,** in relation to which the **DNSP** is requesting the waiver**;**

(d) details of the requested commencement date for the waiver, the requested expiry date (if any), and the reasons for requesting those dates;

(e) details of the costs associated with the **DNSP** complying with the obligation if the waiver of the obligation were refused;

(f) the **regulatory control period(s)** to which the waiver would apply;

(g) any additional measures the **DNSP** proposes to undertake if the waiver were granted; and

(h) the reasons why the **DNSP** considers the waiver should be granted with reference to the matters set out in clause 5.3.2, including the benefits, or likely benefits, of the grant of the waiver to electricity consumers.

5.3 AER's consideration of a waiver application

5.3.1 Requirement to consider a waiver

The **AER** must consider an application made under clause 5.2, and may, subject to this clause 5.3:

(a) grant the waiver subject to any conditions the **AER** considers appropriate; or

(b) grant the waiver as an interim waiver; or

(c) refuse to grant the waiver.

5.3.2 The AER's assessment of the waiver application

In assessing a waiver application and deciding whether to grant a waiver (subject to any conditions) or refuse to grant a waiver, the **AER**:

(a) subject to clause 5.3.4(a), must have regard to:

   i. the **National Electricity Objective**;

   ii. the potential for cross-subsidisation and discrimination if the waiver is granted or refused; and

   iii. whether the benefit, or likely benefit, to electricity consumers of the **DNSP** complying with the obligation (including any likely benefit from increased competition) would be outweighed by the cost to the **DNSP** of complying with that obligation.

(b) may:

   i. reject the application if it considers that the application has been made on trivial or vexatious grounds;

   ii. have regard to any other matter it considers relevant;

   iii. request any further information from the **DNSP** it considers ethical or appropriate;

   iv. invite public submissions on the application;

   v. otherwise conduct such consultation as it considers appropriate with any person.

5.3.3 Form of waiver

The **AER** may grant a waiver that applies:

(a) to one or more **DNSPs** for whom the waiver has been sought.

(b) for the **DNSP's** current **regulatory control period,** the next **regulatory control period** or both; and

(c) subject to such conditions as the **AER** considers appropriate.

5.3.4 Interim waiver

(a) Clause 5.3.2(a) does not apply in relation to a waiver that is expressed to be an interim waiver.

(b) An interim waiver granted under clause 5.3.1(b) ceases to have effect:

   i. when then AER makes a further decision under clauses 5.3.1(a) or 5.3.1(c) to grant or refuse to grant the waiver; or

   ii. on the expiry date (if any) specified by the AER when granting the interim waiver;

   whichever occurs first.

(c) If the AER grants an interim waiver that has an expiry date, and the AER has not made a further decision under clauses 5.3.1(a) or 5.3.1(c) in respect of the waiver application, the AER is deemed to have made a decision to refuse to grant the waiver.

5.4 Publication of waiver etc

i. The **AER** may publish its reasons for granting or refusing to grant a waiver;

ii. The **AER** may publish the terms and conditions of any waiver that is granted.

5.5 Reviewing a waiver

(a) Subject to this clause 5.5, the **AER** may, in its absolute discretion and at any time, vary or revoke a **DNSP**'s waiver(including varying the terms and / or conditions of a DNSP's waiver), as long as it has given the **DNSP** at least 40 days' notice that it is considering doing so.

(b) In deciding whether to revoke a waiver or vary the conditions of a waiver, the AER:

i. must have regard to the matters specified in clause 5.3.2(a);

ii. may do the things, or otherwise have regard to matters, specified in clause 5.3.2(b);

5.6 Reviewing a regional office exemption

(a) Subject to this clause 5.6, the AER may, in its absolute discretion and at any time, vary or revoke a **DNSP's** exemption from the staff and / or office sharing restrictions conferred by clauses 4.2.1(iv) and 4.2.2(iv) of this **Guideline**, as long as it has given the **DNSP** at least 40 days' notice that it is considering doing so.;

(b) In deciding whether to revoke an exemption, the AER:

i. must have regard to the matters specified in clause 5.3.2(a);

ii. may do the things, or otherwise have regard to matters, specified in clause 5.3.2(b);

6 Compliance and enforcement

6.1 Maintaining compliance

A **DNSP** must establish and maintain appropriate internal assurance procedures to ensure it complies with its obligations under this **Guideline**. The **AER** may require the **DNSP** to demonstrate the adequacy of these procedures upon reasonable notice. However, any statement made or assurance given by the **AER** concerning the adequacy of the **DNSP**'s compliance procedures does not affect the **DNSP**'s obligations under this **Guideline**.

6.2 Compliance reporting

6.2.1 Annual compliance report

(a) A **DNSP** must prepare an annual ring–fencing compliance report each **regulatory year** in accordance with this clause 6.2.1, and submit it to the **AER** in accordance with clause 6.2.2.

(b) The annual compliance report must identify and describe, in respect of the **regulatory year** to which the report relates:

i. the measures the **DNSP** has taken to ensure compliance with its obligations under this **Guideline;**

ii. any breaches of this **Guideline** by the **DNSP**, or which otherwise relate to the **DNSP**; and

iii. all **other services** provided by the **DNSP** in accordance with clause 3.1**Error! Reference source not found.**;

iv the nature of all transactions between the **DNSP** and an **affiliated entity**.

(c) The annual compliance report must be accompanied by an assessment of compliance by a suitably qualified independent authority.

(d) Annual compliance reports may be made publicly available by the **AER**.

6.2.2 Timing of annual compliance reporting

(a) Subject to clause 6.2.2(b), a **DNSP** must submit its annual compliance report to the **AER** within 4 months of the end of the **regulatory year** to which the compliance report relates.

(b) A DNSP is not required to submit an annual compliance report in accordance with clause 6.2.1 for its **regulatory year** in which this **Guideline** commences..

6.2.3 Reporting by the AER

The **AER** may publish reports from time to time about **DNSP**s' compliance with this **Guideline** on the basis of information provided to it under this clause 6.2.

6.3 Compliance breaches

A **DNSP** must notify the **AER** in writing within five business days of becoming aware of a material breach of its obligations under this **Guideline**. The **AER** may seek enforcement of this **Guideline** by a court in the event of any breach of this **Guideline** by a **DNSP**, in accordance with the **NEL**.

6.4 Complaints and investigations

The **AER** may, at any time, require a **DNSP** to provide a written response to a complaint or concern the AER raises with the **DNSP** about its compliance with this **Guideline,** including where the AER has previously required the DNSP to provide one or more written responses to the relevant complaint or concern.

Clause 7 Transitional arrangements

7.1. Despite clause 1.1.2:

(a) a DNSP must fully comply with clauses 3.1 and 4.2 in respect of their **existing services** as soon as reasonably practicable, having regard to the likely costs of having to fully comply with those clauses any sooner, but no later than 1 ~~January 2018~~July 2017.

(b) where a **distribution determination** applicable to a **DNSP** results in a change in the classification of a **distribution service** provided by the **DNSP**, and that change materially affects the **DNSP**'s compliance with this **Guideline**, the **DNSP** must ensure that it complies with the **Guideline** within ~~12~~6 months of the commencement date of the **distribution determination**.

7.3. Subject to clause 7.4, the **transitional guidelines** (referred to in clause 11.14.5 of the NER) in force in the **participating jurisdictions** are revoked on 1 December 2016.

7.4. Clause 7.3 does not apply:

(a) to any **transitional guidelines** in force in Victoria or (for the avoidance of doubt) the Northern Territory; and

(b) to the extent that the **transitional guidelines** apply to gas distribution.

APPENDIX J

MICROGRID WORKSHOP QUESTIONS

iaa 12 July 2002 / revised mdws 14 November 2016

CENTRAL DISPATCH

1 How should AEMO obtain the detailed dynamic information about aggregated microgrid export? Should an aggregated microgrid clearance entity (or Network Service Providers) be required to transmit real-time power output data to AEMO's control centres, say every 30 seconds?

2 Could an aggregator microgrid clearance entity provide AEMO with forecasts of microgrid solar PV export each day on half-hour energy basis for the next week and each week on a daily energy basis for next two years? What forms of forecasting of solar PV generation are available or under development and how reliable are they?

3 Can microgrid generation be controlled down if necessary? What power should AEMO have to limit microgrid generation in a particular location if necessary to maintain power system security, such as during network outages?

ANCILLARY SERVICES

4 Are new forms of ancillary services needed to manage the variability of aggregated microgrid generation? For example, should traditional automatic generation control be used to regulate network loading, such as interconnector flows, or to directly balance aggregated microgrid generation variation?

5 How should the costs of additional ancillary services required to manage the variability of aggregated microgrid generation be funded? Should the extra cost be passed to the Generators that collectively cause the requirement, or should they pay a share of the total cost for all requirements?

6 What participants are going to provide the additional ancillary services required to manage the variability of microgrid generation? Will there be enough service available in useful locations?

PLANT AND NETWORK CAPABILITY

7 How are Network Service Providers dealing with reactive power requirements and voltage control? Should the National Electricity Code be amended to make minimum reactive power requirements technology neutral?

8 What frequency and voltage disturbances can existing microgrid generation plant withstand? Which technologies can satisfy National Electricity Code requirements? Which technologies cannot?

9 How will large amounts of variable loading affect network capability? Are existing network rating principles challenged by variability? Can network capability be defined on a probabilistic basis?

REGULATORY ISSUES

10 Should mechanisms be put in place to control the pace of microgrid generation development if it is seen to progress at a faster rate than issues can be resolved? Do licensing authorities consider the likely impact of microgrid generation on the market when granting licences?

11 Should the National Electricity Code and its associated technical standards be amended to address microgrid generation issues? Should the Code maintain and more fully implement the concept of technology neutrality?

12 If the costs of managing the variability of microgrid exported generation are passed on to the Generators as causers, will the level of microgrid exported generation on the power system naturally regulate itself to the most economic level?

APPENDIX K

DEBUNKING AEMO'S MICROGRID MYTHS

mdws 16 November 2016

CENTRAL DISPATCH

1. The myth is that AEMO must believe Community Resilience Microgrids are "renewable from different underlying sources".

- See "*Evaluation of the system performance on power system operation*" December 30th 2009 and particularly its Executive Summary about providing a secure energy source
- Prohibiting prearranged microgrids impairs performance of renewables
- Prearranged microgrids could comply with a universal AEMO standard for Power System Data Communications

2. The myth is that an aggregation of Community Resilience Microgrids cannot be registered with AEMO as scheduled with an acceptable pre-dispatch schedule for an appropriate 24 hour trading period

- Generators with a coal energy source are elite in NEC with particular provisions allowing scheduled times for commitment & de-commitment.
- Capability of AEMO pre-dispatch scheduling software does not allow aggregated microgrids to reach its ultimate potential without limitation
- Weather forecasting is adequate for aggregation of microgrids to submit dispatch bids and offers for a rolling 24 hour trading period
- See "Evaluation of the system performance on power system operation" December 30th 2009 and find word "dispatch" in document.

3. The myth is that the dynamic nature of an aggregation of Community Resilience Microgrids technical envelop would be slow-moving and predisposed to threaten AEMO's power system security responsibilities and obligations

- Coal-fired Generators are at risk of damage to turbine generator components for a step change in power of over 50% MVA rating.
- *Using IEC 61850 GOOSE in Wide-Area Solar-Energy Storage to Speed-up Power Quality Smoothing* presented at Australasian Universities Power Engineering Conference 2016 recognises synthetic inertia issue response speed and provides Frequency Stabilizer as part of Energy Storage Solution for Community Resilience Microgrids.
- Also see "*Control Elements and Control Strategies of a Microgrid*" section in "*Evaluation of the system performance on power system operation*" December 30th 2009.

APPENDIX K

ANCILLIARY SERVICES

4. The myth is AEMO (or DMS) has automatic generation control that is fit for purpose and of suitable performance to systematically manage the power dynamics of Community Resilience Microgrids less than 5MW individually.

- *Using IEC 61850 GOOSE in Wide-Area Solar-Energy Storage to Speed-up Power Quality Smoothing* presented at Australasian Universities Power Engineering Conference 2016 specifies a cycle time of no greater than 100 milliseconds to control power dynamics of Community Resilience Microgrids
- Performance and responsibility for AEMO (or DMS) Power System Data Communications Infrastructure would unduly encumber and impair the risk profile of a Community Resilience Microgrid
- The real technical feasibility is documented in "*Provision of Ancillary Services by Microgrids to Overlaying Grids*" section in "*Evaluation of the system performance on power system operation*" Dec 30th 2009.

5. The myth is that the Market Participants who connect their first Community Resilience Microgrid should be solely responsible for all costs associated with market entrance and shakeout

- Underwriting containment measures for non-technological risks, prosecuting writs served on market management organizations and petitioning market management organizations for associated changes to the regulations are costs that should be borne by the State & Federal Governments
- Administration of Community Resilience Microgrids registration process, mediation of Community Resilience Microgrids consultations & negotiations and authorisation of Community Resilience Microgrids contracts are costs that should be borne by the existing market management organizations
- Proof-of-concept costs for the first Microgrid has been borne "*DF1. Report on field tests for interconnected mode*"; January 2010 Final. STREP project funded by the EC under 6FP, SES6-019864.

6. The myth is that aggregation of Community Resilience Microgrids could not submit offers to AEMO for the provision of regulating capacity or contingency capacity reserve

- See clause 3.1.2 about "*Provision of balancing, spinning or standby reserve services from Microgrid to upstream networks*" in "*DH3. Business Cases for Microgrids* " December 2009.
- See "*Real power or frequency related services*" in clause 3.3 of "*Evaluation of the system performance on power system operation*" Dec 30th 2009.
- See clause 4.1.3 "*Storage Units*" and clause 4.1.4 "*Demand Side Integration*" of "*Evaluation of the system performance on power system operation*" Dec 30th 2009.

APPENDIX K

PLANT AND NETWORK CAPABILITY

7. The myth is that AEMO (or DMS) has software capable of automatically controlling reactive power ancillary services to avoid voltage failure or collapse under single credible contingency events in remote areas

- Reviewing 2002 example of *Planning for Reactive Power Needs of Tasmania*, Transend Networks Pty Ltd, October 2002 (still least cost option) – what financial support does non-network development alternatives receive e.g. synchronous condenser which yields inertia?
- See clause 2.2.2 "*Voltage Regulation Potentials of a Microgrid*" and "*Reactive power and voltage related services*" in clause 3.3 of "*Evaluation of the system performance on power system operation*" Dec 30th 2009.
- See Figure 3-14 "*Voltage Regulation Service Trading in Sample Microgrid*" in "*DH3. Business Cases for Microgrids* " December 2009.

8. The myth is National Electricity Code stipulates for Network Service Providers a universal technical standard to contain the frequency and voltage disturbances seen by Community Resilience Microgrids resulting from electrical faults on power system, or within other Market Participant's facilities

- Quantifying the benefits regarding power quality and security of supply, reduction of losses, economics of operation requires agreement on performance indices. For example, "*DG1. Definition of future Microgrid scenarios and performance indices*" November 30th 2008
- *Using IEC 61850 GOOSE in Wide-Area Solar-Energy Storage to Speed-up Power Quality Smoothing* presented at Australasian Universities Power Engineering Conference 2016 specifies a cycle time of no greater than 100 milliseconds to comply with fault clearance times in NER Table S5.1a2 of more than 110kV but less than 250kV
- "*Convergence of Frequence and Contingency Schemes with Grid SCADA - Island Perspectives*", presented at 23rd Pacific Power Association Conference 2014 provides a protection philosophy and design approach for handling frequency envelope of islanding scenario.

9. The myth is that existing network rating principles do not face a massively greater challenge from the absence of applying technology such as http://www.smartwires.com except adapted for distribution grid purposes.

- Modelling the hourly forecast of solar PV yield over a Community Resilience Microgrids is doable.
- Validating the model data on the ground to account for solar irradiation you see on the ground is doable
- Providing the forecast data via ftp or web is responsibility of Australian Bureau of Meteorology or similar

APPENDIX K

REGULATORY ISSUES

10. The myth is that AEMO has proactively and on its own initiative sought to supervise and control the entrance of Community Resilience Microgrids into the National Electricity Market.

- See clause 2 "*What commercial and regulatory framework for Microgrids?*" in "*DH3. Business Cases for Microgrids* " December 2009.
- Find "tariff" in "*DG1. Definition of future Microgrid scenarios and performance indices*" November 30th 2008
- See clause 2.2 "*Is the current commercial and regulatory framework adequate?"* in "*DH3. Business Cases for Microgrids* " December 2009
- See clause 5.4 "*Definition of Microgrid Benefit Indices*" in "*Evaluation of the system performance on power system operation*" Dec 30th 2009.

11. The myth is that AEMO has ensured that relevant technical standards e.g. AS-4777 are suitable for Community Resilience Microgrids.

- Network Service Providers in Australia operate SCADA management systems using DNP3 for communication to their (mostly) brownfield substations however Community Resilience Microgrids are greenfield and will be deployed with IEC 61850. Gateway-ing these protocols was a 5 year work in IEEE 1815.1 funded by North America yet unfunded by AEMO or Australian Distribution Network Service Providers.
- Network Service Providers in Australia operate SCADA management systems using DNP3 for communication will need its Secure Authentication (SAv5) functionality to link across communications gap to Community Resilience Microgrids. Again funded by North America yet unfunded by AEMO or its Distribution Network Service Providers.
- These are but two examples. In contrast, what has AEMC's Demand management incentive scheme and innovation allowance yielded or is its return on investment in terms of relevant technical standards for Community Resilience Microgrids?

12. The myth is that if AEMO prioritised costs of managing the variability of exported generation from Community Resilience Microgrids, Community Resilience Microgrids would get fair financial return for loss reduction credit.

- Why loss reduction credit? See "*Power Factor Correction - The Easiest, Biggest, Green Initiative*" presented at the Energy NSW 2009 – Managing the Winds of Change: Conference & Trade Exhibition in Sydney, 29th to 30th October 2009.
- See Figure 3-15 "*Loss Reduction Effect of a Sample Microgrid*" in "*DH3. Business Cases for Microgrids* " December 2009.
- See clause 2.2.3 "*Loss Reduction Potentials of a Microgrid*" in "*Evaluation of the system performance on power system operation*" Dec 30th 2009.

APPENDIX L

AUSWEA CONFERENCE ADELAIDE 23-25 JULY 2002

NATIONAL ELECTRICITY MARKET WORKSHOP

iaa 12 July 2002

Assumptions:

Assume 1.5 hours is available, but times can be scaled if necessary (hopefully up not down).

Objective:

To obtain the views of different stakeholders on key issues for the National Electricity Market.

Agenda:

(a) Introduction by Ian Arnott (NEMMCO) (10 minutes)

(b) Central dispatch Issues (18 minutes) - Discussion of three published questions from NEMMCO (6 minutes each) concerning real time data provision to NEMMCO, wind generation forecasting and power system security.

(c) Ancillary Services Issues (18 minutes) - Discussion of three published questions from NEMMCO (6 minutes each) concerning additional service required for wind generation, reimbursement mechanisms and opportunities.

(d) Plant and Network Capability Issues (18 minutes) - Discussion of three published questions from NEMMCO (6 minutes each) concerning reactive power and voltage control, withstanding disturbances and network capability.

(e) Regulatory Issues (18 minutes) - Discussion of three published questions from NEMMCO (6 minutes each) concerning licensing, National Electricity Code and standards and economic regulation.

(f) Conclusion (8 minutes) - where do we go from here?

Session management:

In each of the sessions in (b) to (e), NEMMCO would put a key question and invite comments from the floor. NEMMCO would control the discussion (to keep relevant and manage time). The questions would be sent out with the invitations.

Invitations:

Representatives of the following industry groups should be invited:

Prospective and actual wind Generators

Manufacturers (and technical consultants?)

Network Service Providers

Government (particularly promoters and possibly regulators)

NEMMCO will publish the workshop arrangements and questions on its Internet website.

Planning for Reactive Power Needs of Tasmania

Request for comments and submissions for options to address needs for additional reactive power sources installation in Tasmania

TRANSEND

Planning for the Reactive Power Needs of Tasmania

Transend Networks Pty Ltd owns and operates the electricity transmission system in Tasmania and is seeking submissions on options to address the need for additional reactive power sources.

The loading of the Tasmanian transmission system has now reached levels where existing sources of reactive power are insufficient to enable transmission voltages to be controlled in accordance with the requirements of the Tasmanian Electricity Code (the Code).

Transend invites comments and submissions from interested parties on possible options, including generation and demand side management, that would address, or assist to address, the current and future needs for reactive power support in Tasmania.

Transend may enter into negotiation with proponents of viable solutions in order to

secure their commitment for implementation of proposals that will provide adequate reactive power support and maintain voltages inside the Code requirements.

A paper, “Request for comments and submissions for options to address needs for additional reactive power sources installation in Tasmania”, has been prepared by Transend and can be obtained from Transend’s website (www.transend.com.au), by phoning Sead Pasalic on (03) 6278 6123 or by email: sead.pasalic@transend.com.au.

Submissions, in writing, must be received by close of business on Tuesday 19 November 2002 and are to be addressed to:

Mr Stephen Clark

Acting General Manager Connections and Development

Transend Networks Pty Lt

1 Bowen Road, Moonah

TAS 7009

Produced by Transend Networks Pty Ltd
Planning for Reactive Power Needs of Tasmania
October 2002

TRIM Reference: [Enter the TRIM Number here]

Transend Networks Pty Ltd
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Contents

1. Purpose of this request for comments and submissions

Transend Networks Pty Ltd, the Transmission Network Service Provider in Tasmania, is currently considering options to address the need for additional reactive power sources installations in Tasmania.

The needs have been identified and highlighted in many system studies and the System Controller Planning Statements (see the System Controller, 2001 Planning Statement, Pages 96,101,105,107).

Transend is not able to fulfil the requirements of the Code, Schedule 5.1 in maintaining the minimum voltage level at all connection points at 90% of nominal value and having an adequate reactive reserve margin after critical contingency events. Also, load growth on the system has occurred to the extent that, under certain contingencies, system voltages will fall below this minimum voltage level and in some situations could lead to the system voltage collapse.

Currently, reactive power support in the system is provided mainly by Hydro generators. In addition, there is a total of 180 MVAr reactive support available in capacitor banks installed at Risdon, Lindisfarne and George Town substations. The southern part of the state is dependent upon the Gordon Power Station for reactive support and the recent unavailability of the Gordon Power station has highlighted this issue.

Although Transend has a preferred network option, which would address the above needs for additional reactive power support, it would like to explore the possibility of non-network solutions, such as embedded generation or demand side management options. Transend considers these solutions may offer a viable alternative to it's preferred network option.

Accordingly, this request for comments or submissions is an opportunity for any interested party or parties, particularly prospective embedded generation, demand side management agencies and major industrial customers to come forward with proposals or options that will resolve long–term needs for reactive power support in different regions in Tasmania. Proposals may lead to contractual arrangements with Transend and/or Aurora Energy in securing a long-term reliable solution to the supply needs of the different regions in Tasmania.

Interested parties are invited to make written submissions to Transend on options to provide reactive power support for resolving problems raised in this consultation paper by Tuesday 19 November 2002. All submissions will be posted on Transend's website for public perusal. Details on making a submission are in section 8 of this document.

A summary of submissions will be made to the Reliability and Network Planning Panel (RNPP) as part of Transend's submission. The Panel recommends to the Energy Regulator whether or not a project meets the Regulatory Test.

It should be noted that local government planning and environmental considerations are not discussed in this paper, as they are not within the scope of RNPP's project review. These matters will be addressed through the processes of the relevant authorities.

2. Background

Transend has developed a strategy for additional reactive power sources installation in Tasmania in order to keep voltages inside the Code requirements and to provide required reactive power margin in all connection points with Aurora Energy (Aurora is a distribution network service provider in Tasmania).

The strategy is actually the continuation of a development program endorsed by the Hydro Electric Commission board in July 1995. This development program had envisaged capacitor banks installation at several locations in the State. Since then, capacitor banks have been successfully installed at Risdon, Lindisfarne and George Town substations. A total reactive power support, of 180MVAr, is installed and available at these load centres to improve both the security and quality of supply to Transend's customers.

In the regulated environment in which the electricity industry now operates, not only network proposals, but also non–network options that meet power system requirements should be considered. This request for comments and submissions is an opportunity for interested parties to propose viable non-network development options. The proposals that address, or assist to address the power system requirements, could then be contractually committed in order to best satisfy the requirements of the power system in different regions in Tasmania.

3. Introduction

Points covered in this paper include:

- The need for additional reactive power support
- Tasmanian Electricity Code and Transmission licence requirements
- The proposed network development options for consideration
- Non–network development alternatives
- Project timing

- Information about this consultative process, and
- How to contribute to the discussion.

4. The need for additional reactive power support

The need for additional reactive power support has been identified and highlighted in many system studies and the System Controller Planning Statements (see the System Controller, 2001 Planning Statement, Pages 96,101,105,107).

Transend is not able to fulfil the requirements of the Code, Schedule 5.1 and maintain the minimum voltage level at all connection points at 90% of nominal value and have an adequate reactive reserve margin after critical contingency events without involuntary load shedding.

The availability of reactive power reserve in remote Hydro Tasmania power stations does not guarantee that this reactive power could be transported and used in the load centres. It is dependent on loading conditions of the system, the system component electrical characteristics and system configuration.

In addition, transport of reactive power from remote power stations to load centres has the following undesirable effects:

- Increase in voltage drop in transmission network
- Increase in electrical current loading of transmission network
- Increase in active power losses
- Increase in active energy losses and
- Increase in reactive power losses

The installation of reactive power sources, located at load centres avoids these undesirable effects and is the more preferable option.

4.1 The greater Hobart area and southern region

The greater Hobart area relies heavily on the Gordon power station for continuous, daily reactive power supply. On average, the Gordon power station supplies 100-120MVAr reactive power. This makes it very difficult to organise any maintenance at this power station. The optimisation of water storage use in Tasmania and the requirement for full generation from this Power Station during summer time assumes availability of the Power Station during winter or September for maintenance. Unfortunately, it is the time when voltage support is required in the greater Hobart area. Without the Gordon power station, it is not possible to maintain voltages in the greater Hobart area inside the Code requirements during winter load above 530MW under credible contingency conditions.

Substations located on the Eastern Shore of the Derwent River: Sorell, Triabunna, Bridgewater and Rokeby do not have any local reactive power support and rely on the capacitor bank at Lindisfarne Substation.

Also, the substations south of Hobart including Kingston, Electrona, Knights Road and Kermandie do not have any local reactive power support. Reactive power needs to the region are supplied from New Norfolk and Chapel Street substations via long 110kV transmission lines.

4.2 The North–West region

The North–West region is supplied via the radial 220kV Sheffield-Burnie transmission line. Also, there are two 110kV loops from Sheffield Substation supplying Burnie and Devonport areas.

An outage of Sheffield-Burnie 220kV line is identified as a critical contingency event, which can cause significant voltage drop (up to 17% at Smithton Substation based on 2012 load forecast) and overload of 110 kV transmission lines.

The reactive power support for the region including Sheffield, Burnie, Port Latta, Smithton, Ulverstone, Devonport, Wesley Vale and Railton substations is mainly supplied from the Hydro Tasmania, Mersey Forth and West Coast generators.

There is no local reactive power support available at these substations.

4.3 The greater Launceston and North–East region

Reactive power needs in the greater Launceston area including Hadspen, Trevallyn and Norwood Substations and the North East region including Scottsdale and Derby Substations are mainly provided from Trevallyn and Poatina Hydro Tasmania power stations.

Apart from these Hydro Tasmania generators, there is no local reactive power support in the greater Launceston area or in the North East region.

An outage at Poatina power station has been identified as a critical contingency event. Voltage control at Scottsdale and Derby substations has been handled with a very broad tapping range of transformers at Scottsdale and Derby substations but has very high power losses on the 88kV supply line (up to 15%).

5. The proposed network development option

Transend's preferred network option is to continue with the installation of shunt capacitors in the system. The table below outlines overall reactive power support needs in the different regions and the proposed installation of shunt capacitors:

Region	**Reactive power support proposed (MVAr)**	**Note**
The greater Hobart and Southern region	145	It is proposed to install: 80 MVAr at Chapel Street on 110kV bus 30 MVAr at New Norfolk on 110kV bus 10 MVAR at Kingston on 11kV bus sections 5 MVAr at Knights Road on 11kV bus 10 MVAr at Rokeby on 11kV bus sections 10 Mvar at Sorell on 22kV bus sections
The North West region	90	It is proposed to install: 30MVAr at Burnie on 110kV bus 30 MVAr at Sheffield on 110 kV bus 10 MVAr at Smithton on 22kV bus sections 10 MVAr at Port Latta on 22kV bus sections 10 MVAr at Devonport on 22kV bus sections
The greater Launceston and North East region	65	It is proposed to install: 30 MVAr at Hadspen on 110kV bus 15 MVAr at Trevallyn on 22kV bus sections 10 MVAr at Norwood on 22kV bus sections 10 MVAr at Scottsdale on 22kV bus sections
Total:	**300**	

6. Non–network development alternatives

Potential non-network development alternatives could include demand side management and embedded generation.

To consider any non–network development as a viable alternative, it must have a similar degree of certainty, and be able to deliver similar levels of supply availability, quality and security, as the proposed shunt capacitor installations in the different regions as outlined in the table above. Proponents of any non–network development alternative must accept accountability for delivering such service levels through a contractual arrangement with Transend and/or Aurora Energy.

Submissions are invited for any alternatives that will resolve the issues identified in different regions in Section 4.

Transend welcomes any proposal that will deliver the required level of reactive support needed and provide voltage secure supply to the regions.

7. Project timing

The program would extend over the next five-year period according to the table below.

Financial Year	**Project**	**Note**
2002/03	Chapel St installation	110 kV installation
2003/04	Burnie	110 kV installation
	Port Latta	22kV installation
	Smithton	22kV installation
	Trevallyn	22kV installation
	Scottsdale	22kV installation
2004/05	Hadspen	110 kV installation
	Devonport	22kV installation
	Sorell	22kV installation
	Kingston	11V installation
	Norwood	22kV installation

2005/06	New Norfolk	110 kV installation
	Sheffield	110 kV installation
2006/07	Knights Rd	11kV installation
	Rokeby	11kV installation

8. Consultative process

The Reliability and Network Planning Panel considers major capital augmentation projects proposed by Transend Networks. The Panel recommends to the Energy Regulator whether or not a project meets the Regulatory Test. This Test was recently published by the Energy Regulator and can be found on the Regulator's website at: http://www.energyregulator.tas.gov.au/whatsnew.html

Transend seeks input from interested parties prior to submitting to the Panel its detailed project proposals for individual regions in Tasmania. All submissions will be posted on Transend's website for public reference. Electronic copies of submissions would be appreciated.

8.1 Scope of submissions and comments

Parties wishing to make written submissions are requested to confine comments to those issues raised in this paper. Environmental and Town Planning considerations are not part of the Reliability and Network Planning Panel's scope. These issues are dealt with by State and Local Government agencies and enquires of this nature are to be addressed to the appropriate relevant bodies. The Panel's role is defined in Chapter 12 (clause 12.8.1) of the Tasmanian Electricity Code and is available on the Regulator's website at: http://www.energyregulator.tas.gov.au/Ch12.pdf.

Any party making a written submission may also request a meeting with Transend for further discussion of their position. If any request for such a meeting is received it will take place in Hobart at a venue to be advised, on Friday 22 November, and will be conducted as an open forum with invitations limited to those making written submissions. Parties making submissions should state clearly in the submission that a meeting with Transend is required.

The timetable for the consultative process is as follows:

Submissions close	Tuesday 19 November
Meeting (if requested)	Friday 22 November
Report for the greater Hobart area and southern region submitted to RNPP	Friday 13 December
RNPP meeting	Friday 20 December

Your submission should be sent to:

Mr Stephen Clark
Acting General Manager Connections and Development
Transend Networks Pty Ltd
1 Bowen Road
Moonah, Tas 7009

Power Factor Correction - The Easiest, Biggest, Green Initiative

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This paper was presented at the Energy NSW 2009 – Managing the Winds of Change: Conference & Trade Exhibition in Sydney, Thursday 29th to Friday 30th October 2009.

Abstract

Poor power factor costs our community in increased electricity charges and unnecessary greenhouse gases. Incentives for customers to maintain the required power factor varies across Australia from those that are charged a penalty by way of a kilovoltamperes (kVA) demand charge to those that should comply with the local service rules, legislated or National Electricity Rules requirements.

Some states require operation at only 0.8 power factor which cause series losses of 36% over unity power factor.

This paper sets out to detail what power factor is, the need to improve power factor, state by state power factor requirements and penalties for poor power factor, the costs to the community and the environment, suitable power factor limits, a consistent method of encouraging rectification of poor power factor by penalty tariffs right across Australia, and a method of introduction of the recommended penalty tariff regime.

1. Introduction

The efficient use of electricity assists in the profitability of Australian companies and helps to minimise greenhouse gas emissions. Poor power factor (PF) (or the drawing of voltamperes reactive (VArs) to express it in different terms) unnecessarily adds to inefficiencies and increased greenhouse gas emissions.

Power factor correction can be seen as one of biggest and easiest greenhouse gas initiatives that can be implemented. In this paper we aim to provide a methodology for power factor correction for the future in Australia.

2. What is Power Factor?

2.1. Non-technical Explanation

Various analogies have been used to describe poor power factor including the following:

2.1.1. Horse Pulling Cart

A cart on a railway track is being towed by a horse that is off to the side of the railway track (refer Figure 1). The pull directly between the horse and cart is the apparent power (kVA – apparent power). The effective work by the horse is the cart moving down the track, or the real power (kilowatts (kW) – real power). The pull at right angle to the track does no effective work (kilovoltamperes reactive (kVAr) - the reactive power). The horse would ideally pull the cart directly down the railway track so the apparent power equals the real power, thus minimising wasted energy.

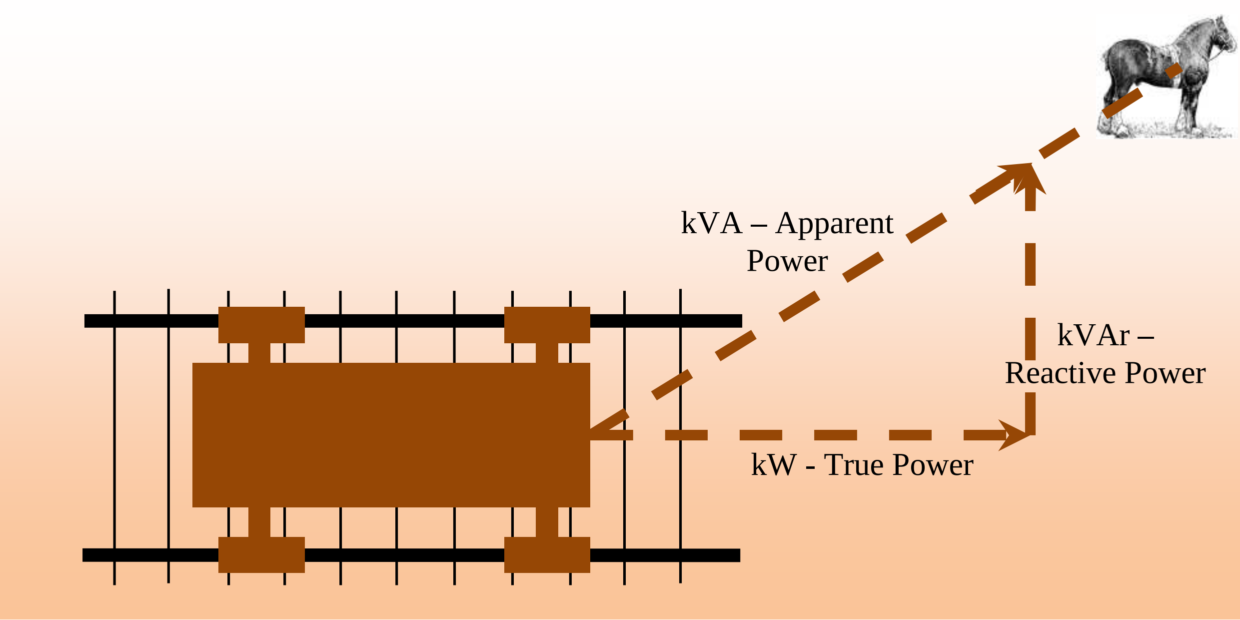

Figure 1 – Power factor analogy with horse pulling cart on tracks off-set [1]

2.1.2. Beer with Froth

A large beer is ordered to quench the thirst of a thirsty individual. The beer has some froth on top that does nothing to quench the individual's thirst – this represents the kVAr or reactive power. The beer does quench the thirst – this represents the kW or real power. The total contents of the mug (the beer and the froth) - represents the kVA or apparent power. The glass must be full of beer with no froth for the person to gain maximum benefit from the glass of beer. It is the same for maximum efficiency with power as the system should not be drawing any kVAr (or froth in the analogy).

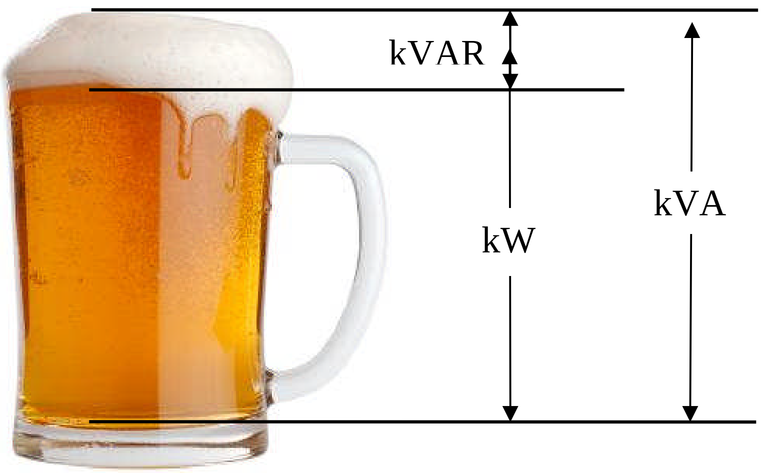

Figure 2 – Power factor analogy using a beer mug

2.1.3. Summary

Just as with the cart being pulled off set or the froth on beer, electrical power can be used inefficiently by what is called poor power factor. It is mainly caused by the use of electric motors but can be easily corrected by the connection of shunt capacitors. These capacitors are installed in a cabinet with a controller that governs how many capacitors are connected to the electricity supply at anyone time (refer Figure 3).

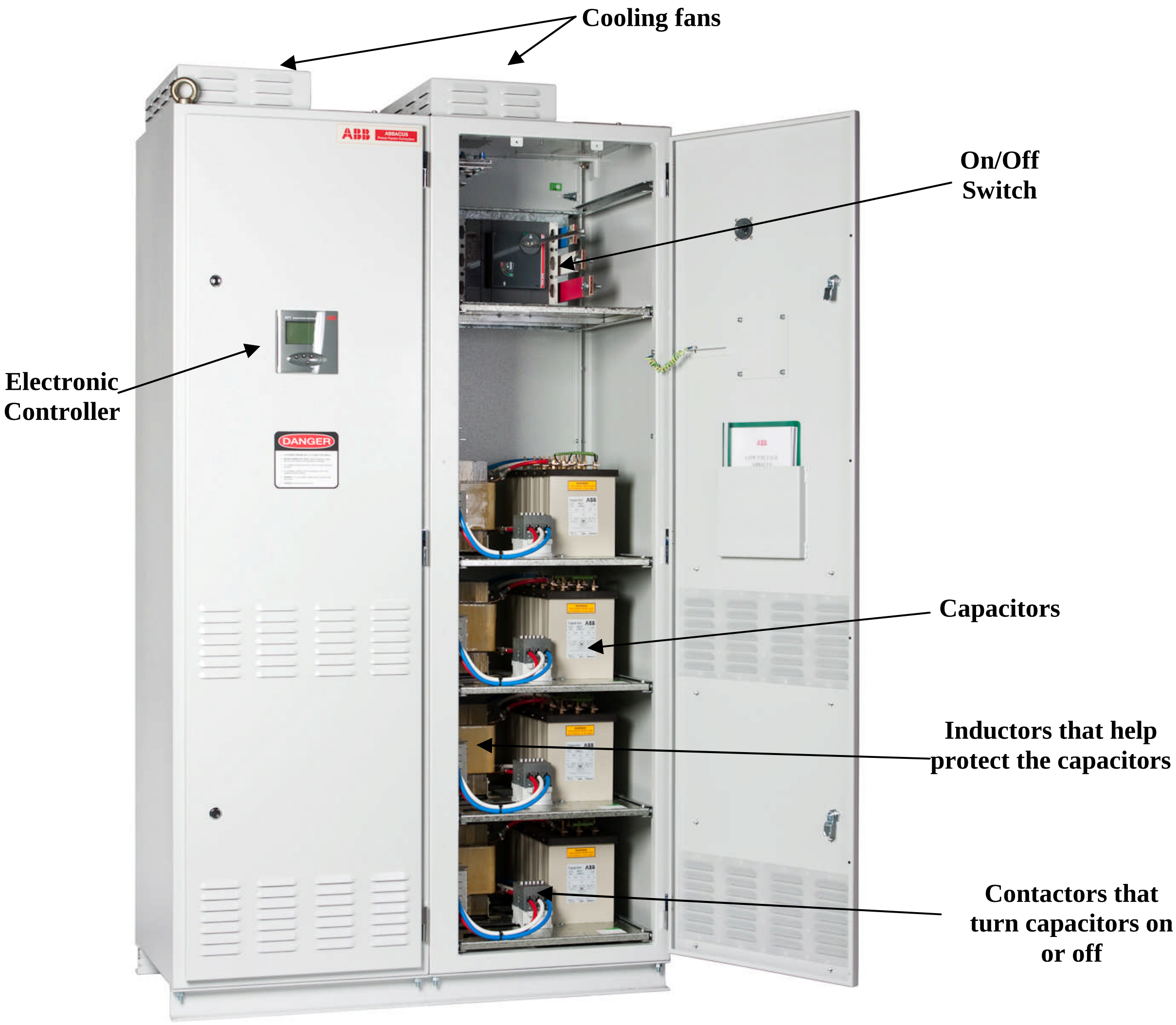

Figure 3 – Low Voltage Power Factor Correction Unit

2.2. Technical Explanation

Power factor, in an alternating current (a.c.) circuit, is the ratio of actual power in watts to the apparent power in volt-amperes.

Power factor = P/EI

If the current and volts are in phase with each other, then the power factor is at 1.0 or unity, as it is also called. However, when there is reactance in the circuit, the current and voltage are out of phase and there will be parts of each cycle where the current is negative and the voltage positive. This results in value of power that is less than the product of the current and the voltage.

There is zero power flow when the current and voltage are out of phase by 90º, as in purely inductive or capacitive circuits (reactive circuits). However, the value of power factor is normally somewhere between 0 and 1 as circuits generally contain a combination of reactance and resistance. Motors cause the current to lag the voltage and hence the power factor will also be lagging. Capacitors cause the current to lead the voltage and hence the power factor will also be leading.

The relationship between components of power flow/power factor are best shown via the power triangle (refer Figure 4). The cosine of the angle Θ equals the power factor:

Power factor = Cos Θ

Cos Θ = kW/kVA

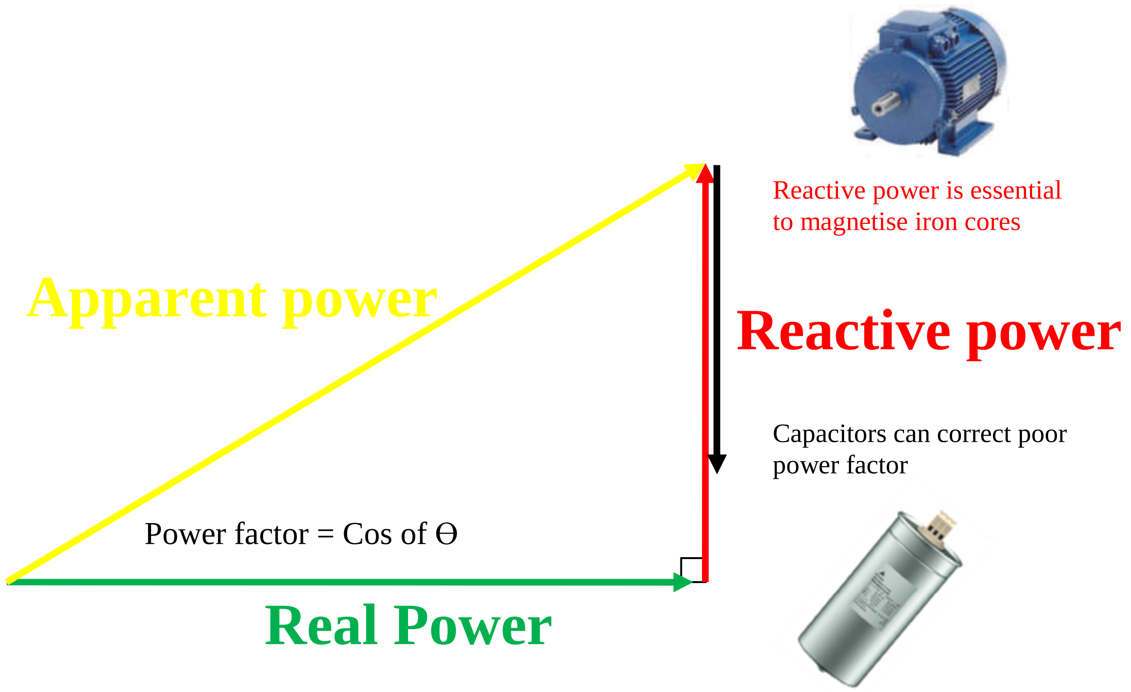

Figure 4 – Power Triangle shows the relationship between all components

It would seem from the previous explanations that reactive power is wasted power but this is not the case. Reactive power is essential for magnetising the iron or steel cores of the countless electric motors, generators, fluorescent light ballasts, transformers etc connected to the electricity network.

Reactive power can be supplied from turbo-generators at power stations either operating in normal generation mode or as synchronous condensers, from capacitor banks or static compensators at transmission nodes or zone substations, or even along feeders. However, it is not essential to supply reactive power over the electricity network at all, because all reactive power needs can be supplied at the local loads themselves by means of low voltage (LV) capacitors or statcoms. What is required in the end is an economic balance between local provision and importation over the network from more remote locations. The greatest savings in network losses comes for locating capacitors as close to loads as possible but this might not always be the most cost effective solution. The provision of local reactive power has traditionally been expressed in terms of Power Factor Correction.

3. Why Improve Power Factor?

Power factor needs to be improved as poor power factor increases line loses and greenhouse gas emissions. The current in a circuit is a factor of the apparent power and hence the larger the current, the greater will be the heating and line loses in the cables supplying the load:

$$\text{Power}_{\text{(line loses)}} = I^2/Z \qquad \text{where Z is the impedance of the cables.}$$

Correcting poor power factor will reduce the current and line losses as the current in the circuit will reduce as the apparent power approaches the real power.

Some power companies impose penalty tariffs for poor power factor in an effort to encourage power factor correction and reduce line loses. The most common method of achieving this is via a peak demand tariff where the electricity user is penalised for the peak kVA for each month. A cost-benefit-analysis of the installation of power factor correction equipment generally shows a pay back within 1-2 years.

The correction of poor power factor also improves network efficiency (and hence improves network utilisation) and releases capacity from the network that can be better utilised at any time in the future. For example:

> *A business may be looking at expanding but the mains cables to the installation and the supply transformer are fully loaded. This upgrade is generally very expensive and often difficult to carry out if the cables are underground. The correction of poor power factor may release enough capacity to negate the upgrade work.*

If this concept is applied right across Australia, then the benefits can be seen with the reduction of line loses and greenhouse gases and the release of network capacity that can defer or negate expensive network upgrades.

Following on from the formula above, system losses can be expressed in terms of real and reactive power (P & Q) instead of current (I). This makes it easier to see the effects of the injection of reactive power in the form of capacitors or static compensators (STATCOMS). The following formula details the relationship between P and Q loss components:

$$\text{Losses} = 3I^2R \qquad \text{Equation 1}$$

$$\text{But } \sqrt{3}VI\cos\Phi = P$$

$$\text{and } \sqrt{3}VI\sin\Phi = Q$$

$$P^2 + Q^2 = 3\,V^2\,I^2\,\cos^2\Phi + 3\,V^2\,I^2\,\sin^2\Phi$$

$$(\,P^2 + Q^2\,)\,/\,V^2 = 3I^2(\,\cos^2\Phi + \sin^2\Phi\,)$$

$$(\,P^2 + Q^2\,)\,/\,V^2 = 3I^2 \qquad \text{Equation 2}$$

Therefore (substituting Equation 2 into Equation 1):

$$\text{Losses} = R.\,(P^2 + Q^2\,)\,/\,V^2$$

Where R is the resistance of the particular circuit element power and V is the Voltage.

The following example shows the relationship between P and Q at 0.8 power factor:

Say	P	= 4 MW @ 0.8 PF
Then	Q	= 3 MVAr
If	R	= 1 ohm
And	V	= 11 kV

Substitute these values into: Losses = R. $(P^2 + Q^2) / V^2$

Losses $= (4^2 + 3^2) / 11^2$ MW

$= (16 + 9) / 121$ MW

= 206kW

This answer is divided between P and Q in the ratio of 16:9.

P = 132kW

Q = 74 kW

Q therefore causes 36% of total losses.

It follows then that if all of the systems above were operating at 0.8 PF then approximately one third of present losses could be saved by operating at UPF and approximately one third of carbon dioxide emissions due to those losses

4. Present State Requirements

Each state has different power factor requirements that electricity users must meet and these requirements are imposed on electricity users by a variety of differing documents. Table 1 provides a summary of these requirements across Australia on a state-by-state basis and includes penalty tariff arrangements for each state. The inconsistencies between states for limits and the application of penalty tariffs are easily seen in Table 1.

Table 1 – State-by State Power Factor and Penalty Tariff Requirements

State	Limits	Measuring Method	Requirement Imposed By	Penalty Tariff Structure
Tasmania	0.75 lagging to 0.8 leading but depends on voltage and demand	Not specified	Aurora Energy Service and Installation Rules	Moving from kW demand to kVA demand
Victoria	0.75 lagging to 0.8 leading but depends on voltage and demand	Not specified	Electricity Distribution Code	Fixed or Peak kW demand
NSW	> 0.9 lag – unity (not leading) Leading and lagging ballast requirements for fluorescent lighting	Not specified	NSW Service and Installation Rules	Peak kVA demand
ACT	>0.9 but not leading. >0.9 for discharge/fluorescent lighting	Not specified	ActewAGL Electricity Service and Installation Rules	Peak kVA demand
Queensland	>0.8 to unity – not leading unless entity agrees HV as per 5.3.5 of NER	Over any 30 minutes	Electricity Regulation 2006	kW capacity and actual demand charge
Northern Territory	<66kV: 0.9 lag – 0.9 leading 132/66kV: 0.95 lag - unity	30 minute averages unless specified	PowerWater: Power Networks – Network Connection Technical Code	Peak kVA demand
Western Australia	0.8 lagging to 0.8 leading or per connection agreement	At period of daily peak demand	WA Electrical Requirements and distributor codes and rules.	Western Power - Peak kVA demand
South Australia	0.8 lagging to 0.8 leading but depends on voltage and demand	At monthly maximum demand	ETSA Utilities Service & Installation Rules	Peak kVA demand. Some old customers on kW demand
Nationally	0.9 lagging to 0.9 leading but depends on voltage	Not specified	National Electricity Rules	N/A

5. Cost to the Community and Environment

There are 16 Distribution Network Service Providers (DNSPs) in Australia that report their Distribution Loss Factors (DLFs) to the Australian Energy Regulator (AER). Only a handful of these DNSPs have reported their total network losses in megawatthours (MWh) and these reports have been compiled in different formats. It is therefore difficult to determine the total amount of electrical losses for the whole of Australia, their cost in dollar terms to electricity customers and their cost in terms of carbon dioxide to the environment. Table 2 summarises what is known. Transmission losses have not been included in this analysis as power factor is most often improved at the transmission company substations.

Table 2 – Australian DNSP Reported Losses

DNSP	*Losses*	*Unit Cost*	*Total Cost*	*Tonnes CO2*	*Year*
Energy Australia	1,541,697 MWh	$ 40	$61,667,872	1,490,821	2006/07
Integral Energy	922,626 MWh	$ 40	$36,905,040	892,179	2006/07
United Energy	409,867 MWh	$ 40	$16,394,680	396,341	2008/09
SP Ausnet	572,148 MWh	$ 40	$22,885,920	553,267	2008/09
PowerCor	766,069 MWh	$ 40	$30,642,760	740,789	2008/09
Subtotal	**4,212,407 MWh**		**$168,496,272**	**4,073,397**	

Table 3 attempts to estimate the total losses and the cost to the community for all Australian DNSP's based on the contents of Table 2. The estimates have been apportioned using customer numbers and a similar type DNSPs from Table 2 as a basis as it was difficult to determine a more suitable methodology. The Q component of line losses has been estimated at one third of total line losses using the logic described further over in this section. It is realised that different pool coefficients (an indicator of the average emissions intensity of electricity) apply from year to year and across the differing states but this has been ignored for the purposes of this paper. However, the results and methodology used in Table 3 provides a guide to the likely line losses and cost to the community that occur each year across Australia.

Table 3 – Estimated Cost to the Community for Poor Power Factor Per Year

DNSP	*Estimated Total Losses (MWh)*	*Estimated Q Losses (MVARh)*	*Estimated Cost due to Q Losses*	*Estimated Tonnes CO2 due to Q*	*Km's of Line*	*Customer Numbers*	*Sub No's*	*Estimate Basis*
Energy Australia	1,541,697	510,000	$20,400,000	495,000	49,000	1,500,000	28,000	2006/07
Integral Energy	922,626	300,000	$12,000,000	295,000		770,000	27,800	2006/07
United Energy	409,867	135,000	$5,400,000	130,000	11,000	300,000		2008/09
SP Ausnet	572,148	190,000	$7,600,000	185,000	46,000	600,000		2008/09
PowerCor	766,069	250,000	$10,000,000	245,000	80,000	683,000		2008/09
ACTEWAGL	160,000	55,000	$2,200,000	50,000		135,000		Integral
Aurora Energy	290,000	95,000	$3,800,000	90,000		259,000		Powercor
Citipower	350,000	115,000	$4,600,000	115,000		295,000		Integral
Country Energy	980,000	325,000	$13,000,000	310,000	200,000	870,000	113,000	Powercor
Energex	1,300,000	430,000	$17,200,000	430,000	50,000	1,300,000	43,420	Energy Australia
Ergon Energy	730,000	245,000	$9,800,000	235,000	150,000	650,000	70,000	Powercor
ETSA Utilites	900,000	300,000	$12,000,000	290,000		803,000		Powercor
Horizon Power	40,000	13,000	$520,000	13,000		36,000		Powercor
PowerWater	80,000	25,000	$1,000,000	25,000		70,000		Powercor
Western Power	940,000	300,000	$12,000,000	300,000	89,700	840,000	58,000	Powercor
Estimated Total	**5,770,000**	**1,903,000**	**$76,120,000.00**	**1,858,000**				

Table 3 provides an annual saving of $76M/year and improving the power factor from 0.8 to unity equates to taking approximately 430,000 cars off the road based on an average of 4.3 tons usage per car per year [2].

The following analysis attempts to verify the accuracy of the estimated percentage of Q losses provided in Table 3.

Figure 5 details a typical daily load plot for a distribution substation, selected at random for this analysis, in an industrial section of Country Energy's Queanbeyan district. It shows the apparent power in kVA over several days.

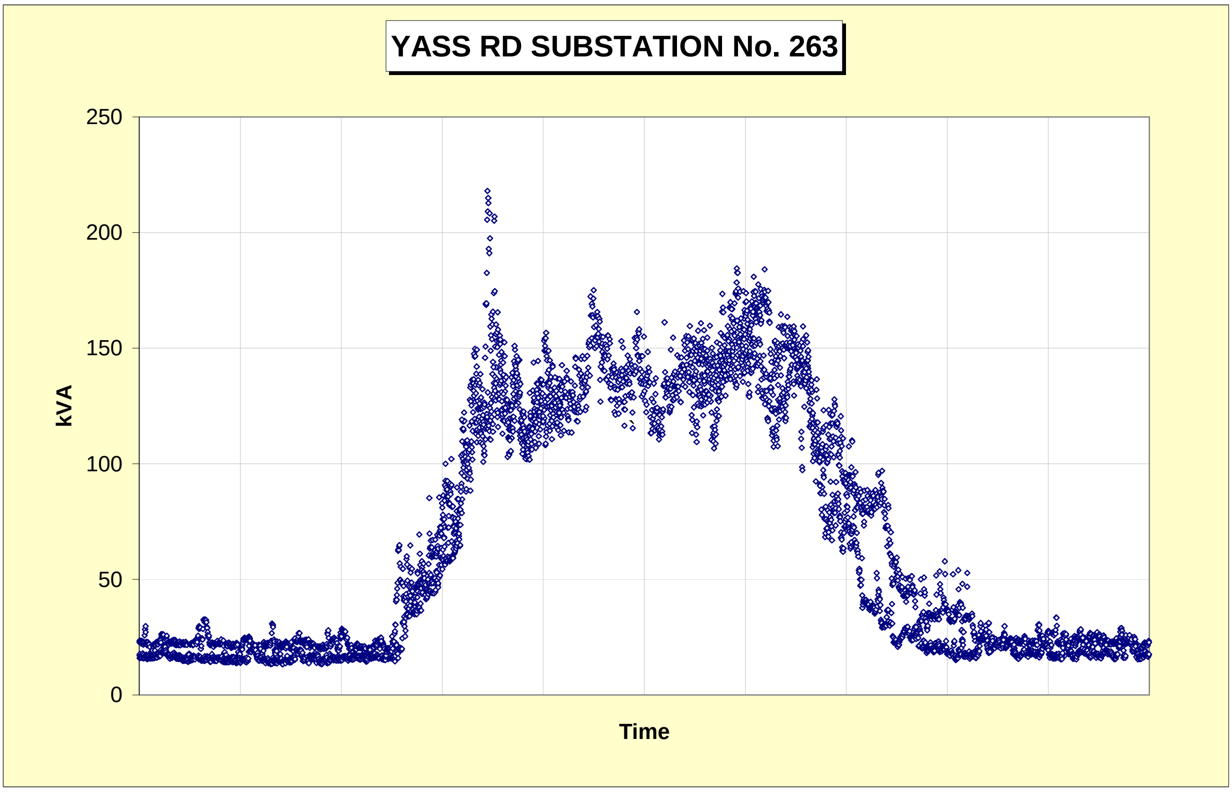

Figure 5 – Apparent power in kVA

Figures 6 and 7 chart, for the same period as Figure 5, P^2 losses in the distribution system due to the real power component and Q^2 losses due to the reactive component of the load. At full load, the losses due to P^2 average around 5kW and those due to Q^2 average around 3kW when the transformer is loaded in the middle section of the charts (power factor correction could totally eliminate this second component).

Table 3 shows Q losses at approximately 33% of total losses which is roughly confirmed by the above figures – 3/8=37%. Whilst this analysis is but one simple example, further detailed analysis has shown that up to 50% of losses are typically caused by Q in NSW but this percentage can increase, particularly in industrial areas where kVA peak demand tariffs are not in place e.g. in other Australian states. Therefore the estimate for the cost to the community in dollar and greenhouse gas terms is likely to be grossly underestimated.

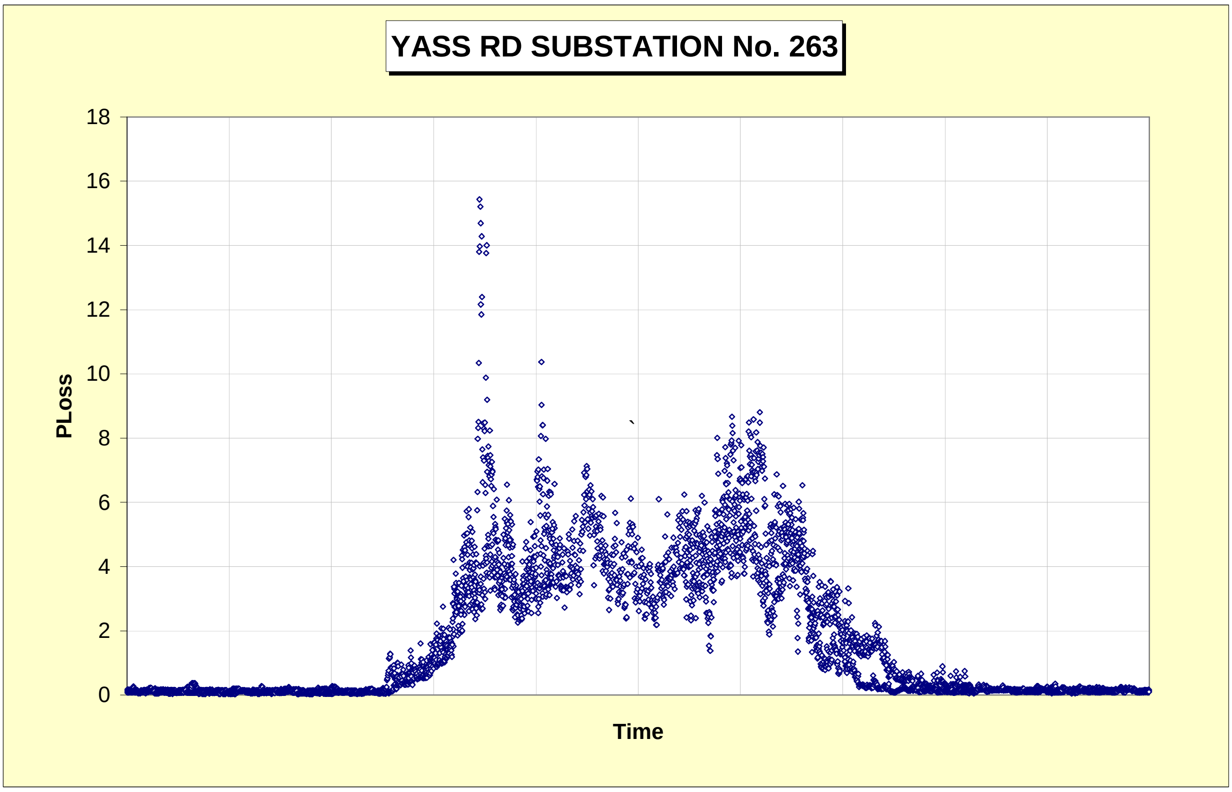

Figure 6 – kW losses due to real power flow P^2

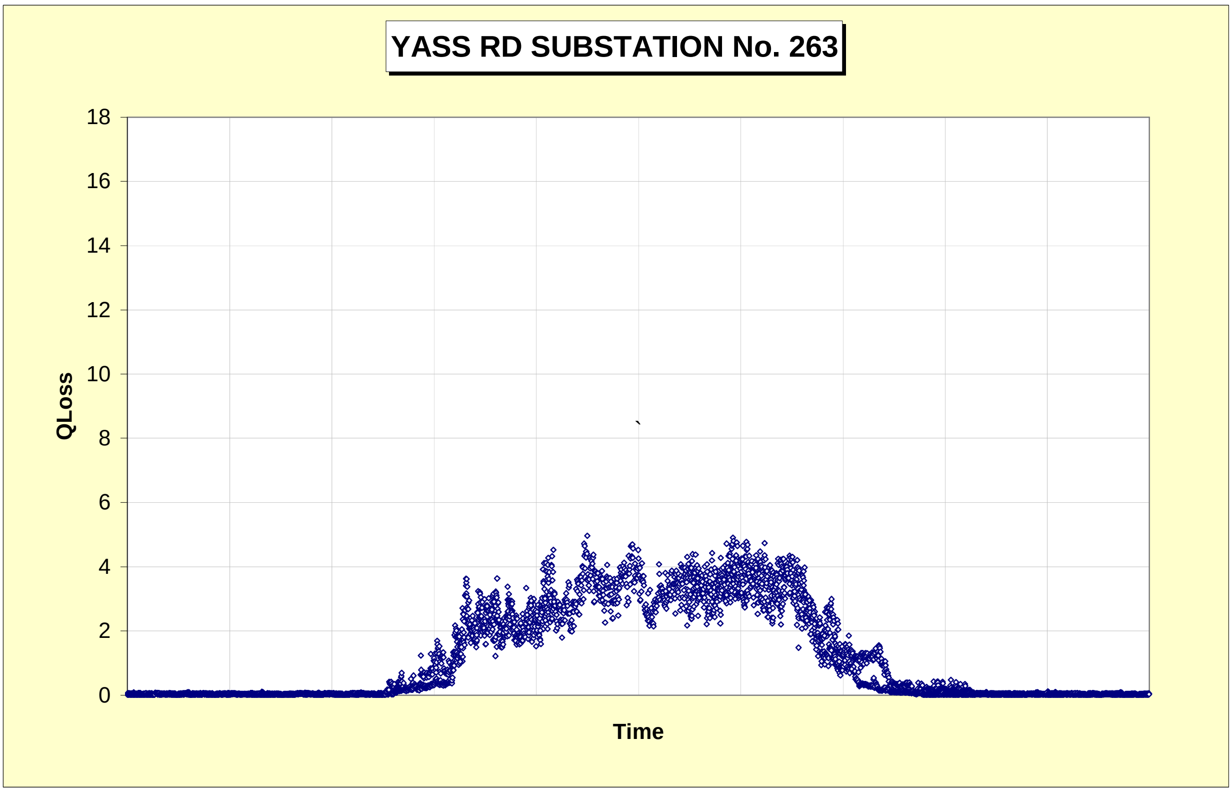

Figure 7 – kW losses due to reactive power flow Q^2

6. Recommended Limits and Tariff Structure

6.1. Limits

Power factor limits are extremely variable across Australian states as seen in Table 1 and some consistency is required if power factor limits are to remain.

It is arguable that power factor limits become obsolete if the right tariff structure is in place as the right tariff structure would dictate economic solutions to poor power factor and excessive VAr usage. Those that do not want to or can't afford to install correction equipment will then simply pay for the absorption of VArs. The issue is then simply a matter of having the right tariff structure and removing present power factor requirements from state based legislation, codes and service rules.

However, if power factor limits are to remain and a limit of 0.9 is selected as the limit, there are still 19% of total lines losses attributable to the VAr component of the load current (see Figure 8). Therefore, a higher target value may be more appropriate.

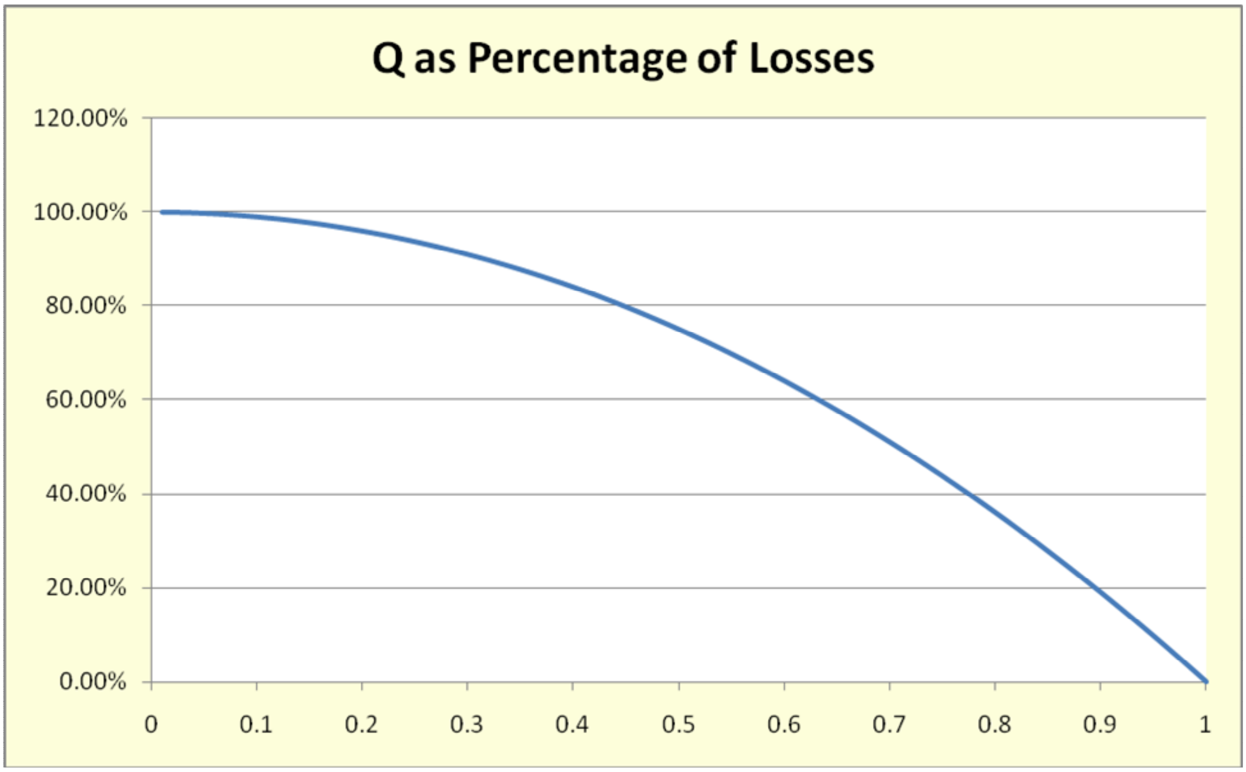

Figure 8 – Q as a Percentage of all Losses

6.2. Tariff Structure

To determine a tariff structure for the future, it is useful to consider both a peak demand and a unit rate to control power factor and the generation of VArs.

Firstly, for peak demand: Presently there are two methods of charging for peak demand i.e. kVA and kW. The kW peak demand does nothing to minimise losses and greenhouse gas emissions. Therefore it is recommended a phasing in of charging by kVA peak demand for those states that presently charge via a kW peak demand tariff. This tariff structure helps distributors provide and maintain assets and customers to cost justify the installation of power factor correction equipment.

Secondly, a peak demand tariff only assists in minimising line losses for VArs, it does not prevent these losses e.g. a large customer hits their peak demand early in the month – the business could then turn off their power factor correction equipment to minimise wear and tear. A charge for apparent power (kVAh's) instead of true power (kWh's) or additional charge on the present status quo for reactive power (kVAr) would provide an additional incentive to reduce VAr absorption from the network. Economics will then dictate to the business on whether they correct to unity power factor, to some lower value or if at all.

All measurements for kVA peak demand, kWh, kVAh or kVArh should be based on the standard 30 minute metering averages presently in place across Australia.

7. Method of Tariff Introduction

It is recommended that the tariff structure proposed by Section 6.2 be introduced after 3 years. This gives business more than enough time to budget for correction equipment and then to have it installed. A staged approach to the introduction of the tariff structure is not recommended as it would make it difficult to cost justify the installation of the equipment in the first few years and achieve little.

8. Tariff Pricing

The recommended kVAh and kVA peak demand pricing should reflect a recovery period for the customer of approximately 18 months. This makes the investment in the correction equipment very attractive for any business, they will also gain the green credits for the initiative.

9. Other Recommendations

Domestic installations have not traditionally corrected for poor power factor as they are generally not large producers of VArs and the installation of power factor correction equipment would unnecessarily complicate matters for domestic electricity customers. However, Minimum Energy Performance Standards (MEPS) could specify requirements for power factor requirements for all basic equipment, e.g. compact fluorescent lamps, when clearly this is an important aspect of their efficiency. Power factor must be taken into MEPS calculations for the resultant star ratings to be truly about efficiency of electrical equipment.

10. Summary and Conclusions

Poor power factor adds to inefficiencies and greenhouse gases and needs to be effectively managed.

Line losses are not only caused by the real power but also by the reactive power with 36% of losses caused by reactive power at 0.8 power factor.

Present requirements to control power factor across Australia are inconsistent and poorly aligned.

The cost to the community of poor power factor is estimated at approximately $76M/yr and 2M tonnes of carbon dioxide each year which equates to taking 430,000 cars off the road. These figures appear to be grossly underestimated due to the higher than expected percentage for Q of total losses (which has been noted by the analysis of energy data from various sites across Australia).

Power factor limits become obsolete with right tariff structure and those that fail to correct for poor power factor would pay additional costs.

Tariffs must dictate economic solutions to poor power factor and excessive VAr usage. A payback period for correction equipment of 18 months is recommended. The recommended tariff includes a kVA demand component and kVAh unit rate. Alternatively, the present system of charging for kWh could continue but with an additional charge for kVArh. This type of tariff structure should be phased in over 3 years to allow companies to budget and install correction equipment.

PF/VAr correction may not be the biggest green initiative but there are opportunities for a significant reduction in electricity delivery costs and greenhouse gas emission.

11. References

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12. Abbreviations

AER	Australian Energy Regulator
CO_2	Carbon Dioxide
cos	Cosine
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
E	Electric Potential
F	Phase Angle
I	Current
km	kilometres
kV	kilovolts
kVA	kilovoltamperes
kVAh	kilovoltamperehours
kVAr	kilovoltamperes reactive
kW	kilowatts
LV	Low Voltage
MEPS	Minimum Energy Performance Standards
MVAr	Megavoltamperes reactive
MVArh	Megavoltamperehours reactive
MW	Megawatts
MWh	Megawatthours
P	Real Power
PF	Power factor
Q	Reactive Power
R	Resistance
STATCOM	Static Synchronous Compensator
V	Voltage
VAr	Voltamperes reactive
Z	Impedance