Draft

Powercor Australia Ltd

Distribution determination 2011–2015

June 2010

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Shortened forms

AER	Australian Energy Regulator
AH	After hours
BH	Business hours
capex	capital expenditure
CPI	Consumer Price Index
cl/cll.	clause/clauses
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DUOS	Distribution use of system
EBSS	Efficiency benefit sharing scheme
ESCV	Essential Services Commission of Victoria
GSL	Guaranteed service level
GWh	Gigawatt hours
m	Million
MAIFI	Momentary average interruption frequency index
MWh	Megawatt hours
NDSC	Negotiated distribution services criteria
NEL	National Electricity Law
NER	National Electricity Rules
opex	operating expenditure
PTRM	Post tax revenue model
RAB	Regulatory asset base
s.	section
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
TUOS	Transmission use of system
WACC	Weighted average cost of capital

Nature and authority

Clause 6.11.1 of the National Electricity Rules (NER) requires the Australian Energy Regulator (AER) to make a distribution determination in relation to Powercor Australia Ltd (hereafter referred to as 'Powercor').

- Clause 6.2.3 states that classification forms part of a distribution determination and operates for the regulatory control period for which the distribution determination is made.

- Clause 6.2.5 (a) states that a distribution determination is to impose controls over the prices of direct control services, the revenue to be derived from direct control services or both.

- Chapter 10 states that an event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed in the NER, that is, a regulatory change event, a service standard event, a tax change event and a terrorism event).

- Clause 6.3.1 requires the AER to make a building block determination in relation to Powercor as a component of a distribution determination. Clause 6.3.2(a) states that the building block determination is to specify the following matters for a regulatory control period:

    (1) the Distribution Network Service Provider's annual revenue requirement for each regulatory year of the regulatory control period;

    (2) appropriate methods for the indexation of the regulatory asset base;

    (3) how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the Distribution Network Service Provider;

    (4) the commencement and length of the regulatory control period;

    (5) any other amounts, values or inputs on which the building block determination is based (differentiating between those contained in, or inferred from, the service provider's building block proposal and those based on the AER's own estimates or assumptions).

- Clause 6.7.3 requires the AER to make a determination specifying requirements relating to the negotiating framework forming part of a distribution determination for a Distribution Network Service Provider is to set out requirements that are to be complied with in respect of the preparation, replacement, application or operation of its negotiating framework.

- Clause 6.7.4(a) requires the AER to make a determination specifying the Negotiated Distribution Service Criteria which forms part of a distribution determination for a Distribution Network Service Provider. This determination is to set out the criteria that are to be applied:

    (1) by the providers in negotiating terms and conditions of access including:

(i) the prices that are to be charged for the provision of negotiated distribution services by the provider for the relevant regulatory control period; or

(ii) any access charges which are negotiated by the provider during that regulatory control period; and

(2) by the AER in resolving an access dispute about terms and conditions of access including:

(i) the price that is to be charged for the provision of a negotiated distribution service by the provider; or

(ii) any access charges that are to be paid to or by the provider.

- Clause 6.7.4(b) sets out that the Negotiated Distribution Service Criteria must give effect to and be consistent with the Negotiated Distribution Service Principles set out in clause 6.7.1.

- Clause 6.12.3(a) allows the AER the discretion to accept or approve, or refuse to accept, or approve, any element of a regulatory proposal.

- Clause 6.12.3(f) requires that if the AER refuses to approve an amount or value referred to in clause 6.12.1, the substitute amount or value on which the distribution determination is based must be:

(1) determined on the basis of the current regulatory proposal; and

(2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

The AER's draft distribution determination, having regard to these clauses, for Powercor is detailed below. Detailed analysis and discussion of the AER's considerations, reasoning and conclusions are set out in the AER's draft decision, released in conjunction with this draft determination. Reference to the draft decision is a reference to the AER's draft decision released with this determination on 4 June 2010, entitled *Draft decision, Victorian draft distribution determination 2011 to 2015*, 4 June 2010. Abbreviations have the meaning given to them in the draft decision.

1 Service classification determination

In accordance with clause 6.2.1 (a) and 6.12.1 (1) of the NER, the AER determines the following classification of services for Powercor for the 2011–2015 regulatory control period. The AER's considerations, reasons and decisions on service classification are also set out in the draft decision at chapter 2 and appendix B.

1.1 Direct control services (standard control services)

1.1.1 Network services

- Constructing the distribution network
- Maintaining the distribution network and connection assets
- Operating the distribution network and connection assets (for DNSP purposes)
- Designing the distribution network
- Planning the distribution network
- Emergency response
- Administrative support (for example, call centre, network billing)
- Location of underground cables

1.1.2 Connection services

- New connections requiring augmentations

1.2 Direct control services (alternative control services)

1.2.1 Fee based services

- Supply abolishment
- Fault response (not DNSP fault)
- Energisation of new connections
- Temporary disconnect / reconnect services
- Wasted attendance (not DNSP fault)
- Service truck visits
- Fault level compliance service
- Reserve feeder
- Photovoltaic installation

- Routine connections (customers below 100 amps)
- Temporary supply services

1.2.2 Quoted services

- Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets
- Supply enhancement at customer request
- Emergency recoverable works (that is, emergency works where customer is at fault and immediate action needs to be taken by the DNSP)
- Auditing of design and construction
- Specification and design enquiry fees
- Elective underground service where an existing overhead service exists
- Covering of low voltage mains for safety reasons
- Damage to overhead service cables caused by high load vehicles
- High load escorts (lifting overhead lines)
- Covering of low voltage mains for safety reasons
- Routine connections (customers above 100 amps)

1.2.3 Public lighting services

- Operation, repair, replacement and maintenance of DNSP public lighting assets

1.2.4 Metering services (fee based)

- De-energisation of existing connections
- Re-energisation of existing connections
- Meter investigation
- Special meter reading
- Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh

1.3 Negotiated services

- Alteration and relocation of DNSP public lighting assets
- New public lighting assets (that is, new lighting types not subject to a regulated charge and new public lighting at green field sites)

1.4 Unregulated services

- The installation, maintenance and provision and repair of watchman (security) lights
- Provision of possum guards

2 Control mechanisms

In accordance with clause 6.2.5, 6.12.1 (11) and 6.12.1 (12), of the NER, the AER determines the following control mechanisms to apply to Powercor's direct control services for the 2011–15 regulatory control period. The AER's considerations, reasons and decisions on control mechanisms are also set out in the draft decision at chapters 4, 19 and 20, and appendices E, F, G and O.

2.1 Standard control services

A weighted average price cap (WAPC). The WAPC formula to apply to Powercor is:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \pm (passthrough_t)$$

where a DNSP has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:

regulatory year 't' is the regulatory year in respect of which the calculation is being made;

regulatory year 't–1' is the regulatory year immediately preceding regulatory year *'t'*;

regulatory year 't–2' is the regulatory year immediately preceding regulatory year *'t–1'*;

p_t^{ij} is the proposed distribution tariff for component j of distribution tariff i in regulatory year t ;

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year t–1 for component j of distribution tariff i;

q_{t-2}^{ij} is the quantity of component j of distribution tariff i that was delivered in regulatory year t–2;

CPI_t is calculated as follows:

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year t;

divided by

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year t–1;

minus one.

X_t is the value of X for year t of the regulatory control period as determined by the AER in chapter 18 of the draft decision;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t;

L_t is the licence fee pass through adjustment to be applied in regulatory year t in accordance with appendix E.2 of the draft decision; and

Pass through$_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year t as compared to regulatory year t–1, as determined by the AER

With the side constraints formula to apply as follows:

$$\frac{\sum_{j=1}^{m} d_t^j \times q_{t-2}^j}{\sum_{j=1}^{m} d_{t-1}^j \times q_{t-2}^j} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\times(1+2\%)\pm(passthrough_t)$$

Where each tariff class 'j' has up to 'm' components, and where:

d_t^j is the proposed price for component j of the tariff class for year t

d_{t-1}^j is the price charged by the DNSP for component j of the tariff class in year t–1

q_{t-2}^j is the audited quantity of component j of the tariff class that was charged by the DNSP in year t–2

X_t is the value of X for year t of the regulatory control period as determined by the AER in chapter 18 of the draft decision. If X>0, then X will be set equal to zero for the purposes of the side constraint formula

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t

L_t is the licence fee pass through adjustment to be applied in regulatory year t

CPI_t is defined as set out in section 4.6.1 of the draft decision.

Pass through$_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year t as compared to regulatory year t–1, as determined by the AER

2.2 Alternative control services

2.2.1 Public lighting

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Powercor's public lighting services is caps on the prices of individual services in each regulatory year of the forthcoming regulatory control period, as set out in table 1 below, and price paths for the remaining regulatory years of the forthcoming regulatory control period.

Table 1 Draft determination on public lighting charges for Powercor ($, 2010)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	40.26	43.07	51.46	50.13	49.96
Sodium high pressure 150 watt	72.01	75.36	79.83	79.57	80.26
Sodium high pressure 250 watt	74.59	78.11	82.85	82.41	83.05
T5 2X14 watt	27.33	28.02	28.79	29.46	30.02
Fluorescent 20 watt	111.91	119.75	143.07	139.35	138.89
Fluorescent 40 watt	111.91	119.75	143.07	139.35	138.89
Mercury vapour 50 watt	55.96	59.87	71.54	69.68	69.44
Mercury vapour 125 watt	54.35	58.15	69.48	67.67	67.44
Mercury vapour 250 watt	56.69	59.36	62.96	62.63	63.12
Mercury vapour 400 watt	65.64	68.74	72.91	72.52	73.09
Mercury vapour 700 watt	99.20	103.89	110.19	109.61	110.46
Sodium low pressure 90 watt	97.22	101.74	107.78	107.41	108.35
Sodium low pressure 180 watt	97.22	101.74	107.78	107.41	108.35
Sodium high pressure 400 watt	99.20	103.89	110.19	109.61	110.46
Incandescent 100 watt	111.91	119.75	143.07	139.35	138.89
Incandescent 150 watt	111.91	119.75	143.07	139.35	138.89
Metal halide 250 watt	99.20	103.89	110.19	109.61	110.46
Metal halide 400 watt	99.20	103.89	110.19	109.61	110.46

Source: AER analysis.

2.2.2 Fee based alternative control services

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Powercor's fee based alternative control services is caps on the prices of individual fee based alternative control services in the first regulatory year of the forthcoming

regulatory control period, as set out in table 2 below, and price paths for the remaining regulatory years of the forthcoming regulatory control period. The AER has not approved price paths for Powercor's fee based alternative control services for 2012–15 and requests that Powercor submit proposed price paths based on the AER's approved labour and materials escalators, set out in appendix K of the draft decision.

Table 2 AER draft determination fee based alternative control services prices for Powercor ($, 2010)

Fee based services	Current price	Proposed price	AER draft decision price
Meter Accuracy Test—single phase—BH	154.65	387.31	152.48
Meter Accuracy Test—single phase—AH	–	420.19	182.66
Meter Accuracy Test—Single phase additional meter—BH	59.83	305.09	41.27
Meter Accuracy Test—multi phase—BH	229.55	479.80	168.58
Meter Accuracy Test—multi phase—AH	–	521.90	202.79
Meter Accuracy Test—Multi phase additional meter—BH	79.75	397.59	57.36
Meter Accuracy Test—CT—BH	–	465.38	216.87
Meter Accuracy Test—CT—AH	–	506.49	263.16
Meter Investigation Test—BH	–	284.47	148.79
Meter Investigation Test—AH	–	308.02	178.06
Reconnections (incl Customer Transfer)—BH	19.97	19.55	17.70
Reconnections (same day)—BH	19.97	30.86	27.98
Reconnections (incl Customer Transfer)—AH	144.97	80.91	73.48
Disconnection (includes DNP)—BH	19.97	20.68	18.73
Special reading / Customer Transfers—BH	19.97	19.55	14.37
Service Truck Visit—BH	154.73	486.05	248.05
Service Truck Visit—AH	309.73	530.69	304.40
Wasted Truck Visit—BH	129.77	302.95	114.73
Wasted Truck Visit—AH	129.77	331.61	138.88
Solar PV Conn—Single phase—BH (unit cost)	–	226.47	167.87
Solar PV Conn—Single phase—AH (unit cost)	–	240.80	191.34
New Connections—DNSP Responsible for metering, customers<100amps			
AMI Single phase—BH	176.72– 319.61	491.85	278.05

AMI Single phase—AH	336.72– 429.61	527.96	320.31
AMI Multi phase DC—BH	269.71– 349.61	624.44	377.74
AMI Multi phase DC—AH	429.70– 459.61	664.00	420.00
AMI Multi phase CT—BH	349.61– 599.71	2 033.41	1 432.50
AMI Multi phase CT—AH	759.71– 789.61	2 196.19	1 695.12
Routine New Connections—DNSP Not Responsible for metering, customers<100amps			
AMI Single phase—BH	119.72–199.61	434.20	220.39
AMI Single phase—AH	279.72–309.61	470.31	262.65
AMI Multi phase DC—BH	119.72–199.61	566.79	320.09
AMI Multi phase DC—AH	279.72–309.61	606.34	362.35
AMI Multi phase CT—BH	119.72–199.61	1 975.76	1 374.85
AMI Multi phase CT—AH	279.72–309.61	2 138.53	1 637.46
Fee based services for which the AER requires further information from Powercor to set a charge			
Reserve feeder	–	–	Further information requested
Re-test of type 5 and 6 meters	–	–	Further information requested

Note: Range of current prices for new connections is due to Powercor's renaming and grouping of these services.

2.2.3 Quoted alternative control services

In accordance with clause 6.12.1(12) of the NER, the control mechanism for Powercor's quoted alternative control services consists of caps on the applicable labour rates in the first regulatory year of the forthcoming regulatory control period, set out in table 3 below, and price paths for the labour rates for the remaining regulatory years of the forthcoming regulatory control period. The approved price path consists of the 2011 quoted services labour rate escalated by the outsourced labour escalation rate the AER approved for standard control services, set out in appendix K of the draft decision. Materials for quoted services are to be recovered at cost.

Table 3 AER draft determination quoted alternative control services prices for Powercor ($, 2010)

Quoted Services	Proposed $/hour rate	AER determination $/hour rate
Emergency recoverable works—BH	112.11	79.80
Emergency recoverable works—AH	123.28	99.75
Damage to overhead service cables caused by high load vehicles - Single Phase—BH	112.11	79.80
Damage to overhead service cables caused by high load vehicles - Multi Phase—BH	112.11	79.80
Damage to overhead service cables caused by high load vehicles - Single Phase—AH	123.28	99.75
Damage to overhead service cables caused by high load vehicles - Multi Phase—AH	123.28	99.75
High load escort—BH	112.11	79.80
High load escort—AH	123.28	99.75

3 Building block determination

3.1 Revenue requirement

In accordance with clause 6.3.2(a)(1) and 6.12.1(2) of the NER, the AER rejects Powercor's proposed annual revenue requirement for each regulatory year of forthcoming regulatory control period. In accordance with clause 6.12.1 (2) and 6.12.1 (11) of the NER, the AER's draft determination on Powercor's revenue requirements and X factors is set out in table 4 below. The AER's considerations, reasons and decision on the annual revenue requirement for Powercor are also set out in the draft decision at chapter 18.[1]

Table 4 AER draft determination on revenue requirements and X factors for Powercor ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		213.4	227.2	241.4	255.9	271.0
Regulatory depreciation		62.0	68.1	74.6	81.5	88.9
Operating expenditure		123.0	127.5	133.1	141.9	147.2
Efficiency carryover amounts		0.0	16.4	0.3	–6.8	0.0
S factor amounts		16.7	–8.0	–4.8	0.9	–32.6
Tax allowance		7.7	8.6	9.2	9.8	10.6
Annual revenue requirements		422.7	439.8	453.8	483.3	485.0
Expected revenues	426.7	413.1	434.8	458.3	481.3	502.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		8.14	0.00	0.00	0.00	0.00

Note: Positive values for X indicate real price increases under the CPI-X formula.
Source: PTRM.

3.2 Indexation of regulatory asset base

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of Powercor's regulatory asset base is the same as that used to escalate the form of control mechanism for that relevant year—that is, to apply the annual change in the *Consumer Price Index: All Groups Index for the Eight State Capitals* as published by the Australian Bureau of Statistics for the September quarter immediately preceding the start of the relevant regulatory year.

[1] The relevant inputs into this table are discussed in the draft decision as follows – chapter 10 (depreciation), chapter 11 (cost of capital), chapter 7 (opex), chapter 13 (efficiency measurement - ESCV's ECM 2006-2010), chapter 12 (corporate income tax and imputation credits), chapter 18 (overall revenue requirement and x factors), chapter 15 (service target performance incentive scheme).

3.3 Schemes

3.3.1 EBSS

In accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER, the EBSS to apply to Powercor for the forthcoming regulatory control period is the AER's *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008. The AER's considerations, reasons and conclusion on the application of the EBSS are also set out in the draft decision at chapter 14.

The excluded cost categories for Powercor are:

- debt raising costs
- self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the DMIA
- GSL payments.

These excluded costs will be recognised in addition to the adjustments set out in section 2.3.2 of the EBSS.

For the purpose of calculating carryover amounts, forecast opex will be adjusted for the actual growth in line length, the number of distribution transformers and zone substations, and customer numbers experienced over the forthcoming regulatory control period using the scale escalation method described in appendix J of the draft decision. The AER's determination on controllable opex for the EBSS is set out in table 5 below.

Table 5 AER draft determination on forecast controllable opex for EBSS purposes for Powercor($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	119.92	121.18	123.35	128.22	129.59	622.26
Adjustment for debt raising costs	–1.17	–1.22	–1.26	–1.30	–1.35	–6.30
Adjustment for self insurance	–	–	–	–	–	–
Adjustment for superannuation[a]	–	–	–	–	–	–
Adjustment for non-network alternatives[a]	–	–	–	–	–	–
Adjustment for DMIA	–0.60	–0.60	–0.60	–0.60	–0.60	–3.00
Adjustment for GSL payments	–1.18	–1.18	–1.18	–1.18	–1.18	–5.88
Forecast opex for EBSS purposes	**116.97**	**118.18**	**120.31**	**125.14**	**126.47**	**607.07**

Note: Totals may not add up due to rounding.
(a) In its regulatory proposal Powercor did not provide sufficient information to identify the amount of opex expended on non-network alternatives and superannuation in the base year. Consequently the AER has been unable to determine the level of opex included in Powercor's opex allowance for these costs. This amount will be identified in the AER's final decision.

3.3.2 DMIS

In accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER, the DMIS to apply to Powercor for the forthcoming regulatory control period is the *Demand management incentive scheme—CitiPower, Powercor, Jemena, SP AusNet and United Energy, April 2009*. The AER's considerations, reasons and conclusion on the application of the DMIS are also set out in the draft decision at chapter 17.

Part A of the DMIS (that is, the DMIA) will apply to Powercor. Part B (the forgone revenue component) will also apply to Powercor. The DMIA is capped at $3 million for the forthcoming regulatory control period and allocated to Powercor in equal annual instalments of $600 000 (real $2010) for each year of the forthcoming regulatory control period. Approval of DMIA amounts by the AER will be subject to satisfaction of the DMIA criteria in the DMIS.

3.3.3 STPIS

In accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER, the STPIS to apply to Powercor for the forthcoming regulatory control period is the AER's *Electricity distribution network service providers, Service target performance incentive scheme,* November 2009. The AER's considerations, reasons and conclusion on the application of the STPIS are also set out in the draft decision at chapter 15.

The applicable parameters are the SAIDI, SAIFI and MAIFI reliability of supply parameters and the telephone answering customer service parameter, defined as follows:

> Telephone answering: Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to calls to payment lines and automated interactive services; and calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls
>
> SAIDI: The sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).
>
> SAIFI: The total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions. [2]

As a transitional provision and in accordance with clause 2.6(c) of the STPIS, the AER will apply the definition of MAIFI as defined by the ESCV:

> The total number of momentary interruptions divided by the total number of distribution customers (where the distribution customers are network or per feeder based, as appropriate). [3]

For the reliability of supply parameters Powercor's network will be segmented into urban, long rural and short rural feeder types, with targets as set out in table 6

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[2] Defined as per the AER's *STPIS*, November 2009, pp. 22-23. SAIDI is measured by average minutes, SAIFI and MAIFI are measured by average interruptions.

[3] Momentary interruptions are defined as per *Information Specification (Service Performance) for Victorian Electricity Distributors*, 1 January 2009, p. 30

Table 6 AER draft determination performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter for Powercor

Feeder	Parameter	Powercor
Urban	SAIDI	82.47
	SAIFI	1.263
	MAIFI	1.412
Rural short	SAIDI	114.81
	SAIFI	1.565
	MAIFI	2.881
Rural long	SAIDI	233.76
	SAIFI	2.540
	MAIFI	6.535
	Telephone answering	62.62 per cent

Source: AER analysis.

In accordance with clause 2.5(a) of the STPIS the cap on revenue at risk is set at ±5 per cent. In accordance with clause 5.2(b) of the STPIS there is a cap on the revenue at risk of ±0.5 per cent for the telephone answering parameter.

The incentive rate to apply to each applicable parameter are calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of the STPIS, and are set out in table 7.

Table 7 AER draft determination on incentive rates for SAIDI, SAIFI, MAIFI and the telephone answering parameter for Powercor

Feeder	Parameter	Powercor
Urban	SAIDI	0.0577
	SAIFI	3.7592
	MAIFI	0.3007
Rural short	SAIDI	0.0323
	SAIFI	2.5761
	MAIFI	0.2061
Rural long	SAIDI	0.0280
	SAIFI	2.8058
	MAIFI	0.2245
	Telephone answering	–0.040

Source: AER analysis.

The AER will close out the ESCV's s factor scheme by applying the following methodology:

1. The DNSP's reliability performance for 2010 is estimated as the actual performance will not be known until part way through 2011.[4] The AER considers that an appropriate estimation methodology to use is the average performance over the past five years (2005–2009).
2. S”t is calculated for 2009 and 2010 in accordance with the ESCV's S factor scheme.
3. S’t for 2011 and 2012 is calculated by banking S”t in accordance with the DNSP’s stated intentions.[5] The WACC to apply in the banking calculation is the 2006–10 EDPR WACC.
4. S’t for 2013–2018 is held constant at 0.
5. St is calculated for 2010–2018 in accordance with the ESCV's S factor scheme. The AER notes that St and S't-6 become zero after 2018 and at this time the effects of the ESCV’s S factor scheme have been fully accounted for.
6. The estimates of forecast revenue are to be the approved 2010 tariff prices multiplied by the demand forecast. For the years 2016–18, forecast revenues are to be held constant at 2015 levels.

[4] The AER has included actual 2009 figures provided by the Victorian DNSPs, but has not assessed the results. The AER will undertake this assessment prior to publishing its Final Decision.

[5] Consistent with the current operation of the ESCV's S factor scheme, the Victorian DNSPs will be able to make a final decision whether or not to use the s-bank mechanism when setting tariffs for 2012.

7. The S factor is applied to the forecast revenues for 2011–18. For 2011–15, the difference between the estimates of tariff revenues, excluding and including the S factor is then factored into the building blocks.
8. The difference between the estimates of tariff revenues, excluding and including the S factor, for 2016–18 are converted to 2015 values in net present value terms and applied to the building blocks in 2015. The WACC to apply to this NPV calculation is the 2011–15 EDPR WACC.

The GSL component of the STPIS will not apply while the ESCV's GSL scheme remains in place. In the event that the ESCV's GSL scheme is withdrawn the AER will implement the GSL scheme in the AER's STPIS. The AER concludes that, pursuant to clause 6.5.6(a)(2) of the NER, it will include its forecast total GSL payments in table 8 as a line item in the opex allowance, for each year in the forthcoming regulatory period.

Table 8 AER draft determination on GSL payments for Powercor ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	5	96
Connections not made on agreed date total	51	9 570
Connections not made—1–4 day delay	45	7 120
Connections not made—5+ day delay	6	2 450
20 hours of interruptions	7 029	702 850
30 hours of interruptions	911	136 688
60 hours of interruptions	84	18 975
10 interruptions	2 153	215 300
15 interruptions	8	1 238
30 interruptions	–	–
24 momentary interruptions	2 570	64 238
36 momentary interruptions	766	26 793
Streetlights	41	408
Total		1 176 156

Source: AER analysis.

The major event day threshold is to be set at 2.8 beta from the mean. The major event day threshold is to be calculated in accordance with section 3.3 of the STPIS.

The St factor derived under the STPIS and applied to the WAPC formula for 2011 and 2012 will be zero.

3.4 Regulatory control period

In accordance with clause 6.3.2(a)(4) and 6.12.1 (2) of the NER, the regulatory control period is five years long, commencing 1 January 2011 and ceasing on 31 December 2015.

3.5 Other amounts, values or inputs

In accordance with clause 6.3.2(a)(5) and 6.12.1(10) of the NER, any other amounts, values or inputs on which Powercor's building block determination is based are as specified in below.

3.5.1 RAB roll forward

In accordance with clause 6.12.1 (6) of the NER, the total opening asset base for Powercor as at 1 January 2011 is $2204.9 million for standard control services. Table 9 illustrates the AER's forecast roll-forward of Powercor's RAB.

Table 9 The AER's considerations, reasons and decision on the RAB for Powercor are also set out in the draft decision at chapters 9 and 18AER forecast roll-forward of the RAB for Powercor ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	2204.9	2347.8	2494.1	2644.5	2800.4
Net capital expenditure	204.8	214.4	225.0	237.4	248.6
Indexation of opening RAB	56.8	60.5	64.2	68.1	72.1
Straight-line depreciation	118.7	128.5	138.8	149.6	161.0
Closing RAB	2347.8	2494.1	2644.5	2800.4	2960.1

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

3.5.2 Capital expenditure

In accordance with clause 6.12.1 (3) (i) of the NER, the AER does not accept Powercor's forecast capex for the forthcoming regulatory control period. In accordance with clause 6.12.1 (3) (ii) of the NER, the AER's considerations, reasons and decision on capex for Powercor are also set out in the draft decision at chapter 8. The AER's estimate of Powercor's total capex for the forthcoming regulatory control period is set out in table 10.[6]

[6] The relevant inputs into forecast capex are discussed in the draft decision as follows – chapter 6 (outsourcing and related party transactions), appendix N (equity raising costs)

Table 10 AER draft determination on capital expenditure for Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	209.1	212.5	215.0	218.5	222.5	**1077.5**
Direct overheads	5.1	5.2	5.3	5.4	5.5	**26.6**
Indirect overheads	22.6	23.0	23.4	23.9	24.2	**117.2**
Cost increases	11.2	14.0	15.9	18.5	19.3	**78.9**
Margins	–	–	–	–	–	**–**
Less contributions	–56.7	–57.6	–58.0	–58.9	–59.8	**–291.0**
Total net capex	**191.4**	**197.1**	**201.6**	**207.4**	**211.8**	**1009.2**

3.5.3 Cost of capital

In accordance with clause 6.12.1 (5) of the NER, the AER's determination on Powercor's WACC is set out in table 11. The AER's considerations, reasons and decision on the cost of capital for Powercor are also set out in the draft decision at chapter 11.

Table 11 AER draft determination on WACC parameters for Powercor

Parameter	Powercor
Nominal risk-free rate	5.65%
Real risk-free rate	3.00%
Expected inflation rate	2.57%
Gearing level (debt/equity)	60%
Market risk premium	6.5%
Equity beta	0.8
Debt risk premium	3.25%
Nominal pre-tax return on debt	8.90%
Nominal pre-tax return on equity	10.85%
Nominal WACC	9.68%

3.5.4 Depreciation

In accordance with clause 6.12.1 (8) of the NER, the AER does not accept Powercor's depreciation schedule. The AER's considerations, reasons and decision on

depreciation for Powercor are also set out in the draft decision at chapter 10. The AER's determination on depreciation for Powercor is set out in table 12.

Table 12 AER draft determination on regulatory depreciation for Powercor ($'m, nominal)

	2011	2012	2013	2014	2015	Total
Powercor	62.0	68.1	74.6	81.5	88.9	**375.1**

3.5.5 Operating expenditure

In accordance with clause 6.12.1 (4) (i) of the NER, the AER does not accept Powercor's forecast opex for the forthcoming regulatory control period. In accordance with clause 6.12.1 (4) (ii) of the NER, the AER's considerations, reasons and decision on opex for Powercor are also set out in the draft decision at chapter 7. The AER's estimate of Powercor's total opex is set out in table 13.[7]

Table 13 AER draft determination on operating expenditure for Powercor ($m 2010)

	2011	2012	2013	2014	2015	Total
Powercor proposed opex	**165.0**	**171.3**	**178.7**	**187.3**	**199.9**	**902.2**
AER opex build-up						
AER base year costs	115.7	115.7	115.7	115.7	115.7	578.3
AER scale escalation	0.6	1.2	1.8	2.3	2.9	8.8
AER real cost escalation	2.5	3.8	5.4	7.6	8.7	28.1
AER step changes	–1.8	–2.5	–2.5	–0.5	–0.8	–8.1
AER debt raising costs	1.2	1.2	1.3	1.3	1.3	6.3
AER self insurance	–	–	–	–	–	–
AER other[a]	1.8	1.8	1.8	1.8	1.8	8.9
AER total opex	**119.9**	**121.2**	**123.3**	**128.2**	**129.6**	**622.3**
Adjustment	**–45.1**	**–50.1**	**–55.4**	**–59.0**	**–70.3**	**–280.0**
Adjustment (per cent)	**–27.3**	**–29.3**	**–31.0**	**–31.5**	**–35.2**	**–31.0**

(a) DMIS, GSL.

[7] The relevant inputs into this table are discussed in the draft decision as follows – chapter 6 (related parties and outsourcing), appendix H (outsourcing and related parties), appendix I (benchmarking), appendix J (scale escalators), appendix K (labour and material cost escalators), appendix L (step changes), appendix M (self insurance), appendix P (debt raising costs).

3.5.6 Cost of corporate income tax

In accordance with clause 6.12.1 (7) of the NER, the AER's determination on corporate income tax liability for Powercor is set out in table 14. The AER's considerations, reasons and decision on cost of corporate income tax for Powercor are also set out in the draft decision at chapter 12.

Table 14 AER draft determination on corporate income tax liability for Powercor ($'m, nominal)

	2011	2012	2013	2014	2015
Powercor	7.7	8.6	9.2	9.8	10.6

3.5.7 Other values, amounts and inputs

In accordance with clause 6.12.1(10) of the NER, the AER has determined other values, amounts and inputs.

These other values, amounts and inputs relate to growth forecasts, the ESCV's s-factor carryover amounts, and the ESCV's efficiency carryover mechanism (ECM) carryover amounts.

The AER's considerations, reasons and decisions on growth forecasts, s-factor carryover amounts and ECM carryover amounts for Powercor are set out in the draft decision at chapters 5, 13 and 15 respectively. The AER's determinations on these additional inputs for Powercor are set out in tables 15, 16 and 17 below.

Table 15 AER draft determination on growth forecasts for Powercor

	2011	2012	2013	2014	2015
Sum of non–coincident zone substations (MW)	2 327	2 437	2 569	2 669	2 747
Energy consumption (GWh)	11 163	11 463	11 764	11 994	12 151
Customer numbers	715 541	727 610	739 714	752 719	766 214

Table 16 AER draft determination on building block amounts resulting from ESCV ECM carryover for Powercor ($'m, 2010)

	2011	2012	2013	2014	Total
Powercor	–	15.6	0.3	–6.2	**9.7**

Table 17 AER draft determination on building blocks amounts resulting from the ESCV S factor for Powercor ($'m, 2010)

	2011	2012	2013	2014	2015
Powercor	16.25	–7.57	–4.49	0.78	–28.71

4 Pass through events

In accordance with chapter 10 and clause 6.12.1 (14) of the NER, the nominated pass through events to apply to Powercor are listed below. The AER's considerations, reasons and decision on pass throughs are also set out in chapter 16 of the draft decision.

- a declared retailer of last resort event:

  A declared retailer of last resort event is the occurrence of an event whereby an existing retailer is unable to continue to supply electricity to its customers and those customers are transferred to the declared retailer of last resort, and which:

  (a) falls within no other category of pass through event; and

  (b) materially increases the costs of providing direct control services.

  For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

- insurer credit risk event:

  An event where the insolvency of the nominated insurers of the DNSP, as a result of which the DNSP:

  incurs materially higher or lower costs for insurance premiums than those allowed for in the distribution determination; or

  in respect of a claim for a risk that would have been insured by the DNSP's insurers, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.

  For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

- an insurance event:

  An event that would be covered by an insurance policy but for the amount that materially exceeds the policy limit, and as a result the DNSP must bear the amount of that excess loss. For the purposes of this pass through event, the relevant policy limit is the greater of the actual limit from time to time and the limit under the DNSP's insurance cover at the time of making this regulatory proposal. This event excludes all costs incurred beyond an insurance cap that are due to the DNSP's negligence, fault or lack of care. This also excludes all liability arising from the DNSP's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by the DNSP.

  For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

- a natural disaster event:

  Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services.

  For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

5 Negotiating framework determination

In accordance with clause 6.12.3(g) and 6.12.1(15) of the NER, the AER is satisfied that Powercor's negotiating framework adequately complies with the requirements of Part D of the NER. The AER's considerations, reasons and decision on negotiating frameworks are also set out in chapter 3 and appendix C of the draft decision.

6 Negotiated distribution services criteria determination

In accordance with clause 6.7.4 and 6.12.1 (16) of the NER, the negotiated distribution services criteria (NDSC) to apply to Powercor are set out at appendix D of the draft decision. The AER's considerations, reasons and decision the NDSC are also set out in chapter 3 draft decision.

7 Other constituent decisions

7.1 Compliance with control mechanisms

In accordance with clause 6.12.1(13) of the NER, the AER determines that compliance with the relevant control mechanisms for direct control services is to be demonstrated as follows.

7.1.1 Standard control services

Compliance with the control mechanism standard control services will be monitored as set out in appendix E of the draft decision.

7.1.2 Alternative control services

Compliance with the alternative control services control mechanisms will be demonstrated through an annual pricing proposal process.

Compliance with the control mechanism for public lighting services is to be demonstrated by Powercor through the annual pricing approval process and be consistent with this determination for the relevant regulatory year. Operation, maintenance and repair charges approved by the AER will be subject to CPI adjustment for each year of the forthcoming regulatory control period.

7.2 Procedures for assigning customers to tariff classes

In accordance with clause 6.12.1(17), the AER's draft determination on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another is set out in appendix G of the draft decision.

7.3 Depreciation for establishing the RAB as at the commencement of the following regulatory control period

In accordance with clause 6.12.1(18), the AER determines that depreciation based on actual capital expenditure will be used to determine Powercor's regulatory asset base as at the commencement of the following regulatory control period.

7.4 Recovery of TUOS charges

In accordance with clause 6.12.1 (19) of the NER, the AER's draft determination on how Powercor is to report to the AER on its recovery of TUOS charges for each regulatory year of the forthcoming regulatory control period is set out in appendix F of the draft decision.