Western Power Networks

Price Publication - Part E

Support Services Prices for the South West Interconnected System 1 July 2005 – 31 December 2005

WESTERN POWER NETWORKS
PRICING PUBLICATIONS

PART A REVENUE PAPER

PART B PRICING PAPER

PART C PRICE SCHEDULES

C1 STANDARD NETWORK TARIFFS AND PRICES
FOR THE SOUTH WEST INTERCONNECTED NETWORK
2005/2006

C2 TRANSITION NETWORK TARIFFS AND PRICES
FOR THE SOUTH WEST INTERCONNECTED NETWORK
2005/2006

C3 STANDARD NETWORK TARIFFS AND PRICES
FOR THE NORTH WEST INTERCONNECTED NETWORK
2005/2006

C4 TRANSITION NETWORK TARIFFS AND PRICES
FOR THE NORTH WEST INTERCONNECTED NETWORK
2005/2006

C5 NETWORK TARIFFS AND PRICES
FOR REGIONAL NETWORKS
2005/2006

C6 MISCELLANEOUS NETWORK PRICES
2005/2006

PART D NETWORK PRICE APPLICATION GUIDE

**PART E SUPPORT SERVICES PRICES
FOR THE SOUTH WEST INTERCONNECTED SYSTEM
1 July 2005 – 31 December 2005
(Spinning Reserve, Standby, Balancing Energy, Top Up & Spill Energy and Intermittency services)**

PURPOSE OF THIS DOCUMENT

This document provides the methodology and prices for ***"support services"*** required in conjunction with network access arrangements in the South West Interconnected System for the second half of the 2005 calendar year.

These services include ***spinning reserve (regulation and contingency), standby, balancing energy, top-up & spill energy*** and ***intermittency***.

CONTENTS

Summary of Charges

Application of Charges

This paper gives the support charges relating to access to the Western Power SWIS. The detail of each price and charge can be found in the appropriate section, but a summary of the charges and how they relate to users is given below.

User Type	Regulation	Contingency	Standby	Intermittency
Dispatchable Generator	No	Yes	No	No
Intermittent Generator	Yes	Yes	No	Yes
Load	Yes	No	Yes	No

A dispatchable generator is one for which the output can be controlled to a defined level.

An intermittent generator is one for which the output is determined by its fuel supply. Included in this class are wind and solar generators.

Goods and Services Tax

For clarity, all calculations that explain how the price for a service is determined are expressed exclusive of GST. All actual service prices will have the GST component clearly indicated.

Charges and Prices effective 1 July 2005

The *Regulation Prices* for Intermittent Generators are

For generators >= 10MW installed capacity, based on their installed capacity

$2,066 + $207 GST /MW/year.

note that this price may change from 1 January 2006 to around $8,000 +$800 GST /MW/year

For generators >= 5MW and <10MW installed capacity, based on their installed capacity

$689 + $69 GST /MW/year.

note that this price may change from 1 January 2006 to around $2,666 + $267 GST /MW/year

For generators < 5 MW installed capacity, based on their output

0.025 cents + 0.002 cents GST /kWh

The *Regulation Price* for Loads, based on consumption. is

0.025 cents + 0.002 cents GST /kWh

The *Contingency prices* for dispatchable generators based on installed capacity and running hours and intermittent generators based on installed capacity, capacity factor and running hours are:

GENERATOR UNIT MAXIMUM NET OUTPUT (MW)	PRICE ($/h)
<10	**0.00 + 0.00 GST**
10 - 45	**8.34 + 0.83 GST**
46 - 65	**24.75 + 2.47 GST**
66 - 125	**92.50 + 9.25 GST**
126 - 200	**177.76 + 17.78 GST**
200 - 330	**268.57 + 26.86 GST**
>330	**POA**

The *Intermittency Prices* for intermittent generators are

For generators >= 10MW installed capacity, based on their installed capacity:

$1,870 + $187 GST /MW/year.

For generators >=5MW and < 10MW installed capacity, based on their installed capacity:

$623 + $62 GST/MW/year.

For generators < 5 MW installed capacity:

nil

The *Excess Standby Generation Fee* is

$20 + $2 GST /kW/excess demand period

The *Standby Price* for loads offered by Western Power is dependent on the difference between the capacity required to support the standby reservation and the capacity provided by generation. This is a simple version of capacity mechanisms used in electricity markets. The election of the standby reservation is the election of the access user and is generally but not necessarily equal to the peak demand of the load.

The generation capacity required to support the standby generation is 120% of the standby capacity reservation.

The capacity provided by the generator is a function of its availability. For a dispatchable generator it is assumed equal to 96% of the installed capacity. For an intermittent generator it is the output of the generator during times of system peak demand. For new intermittent generators a default of 23% of the installed capacity is assumed unless the proponent can demonstrate that the reliable capacity provided by their intermittent generator is more than this assumed value.

The difference is charged at

$**67.47 /kW/year**

The Standby Capacity Price is expressed in $/kW for the Standby Generation Reservation. Each situation will be considered for its particular circumstance, especially for intermittent generators.

Note a minimum of $16.19 + $1.62 GST /kW/year applies to the Standby Capacity Price.

Users should refer to the example calculations in the body of the report to assess the Standby Capacity Price.

Payments effective 1 July 2005

Payments are made to contracted Interruptible Loads as they are used to supply support services in the SWIS

The payment is based on the interruptible load's average on-peak demand and is

$85,000 + $8,500 GST /MW/year

ANCILLARY SERVICES - METHODOLOGY AND SERVICE PRICES

1. INTRODUCTION

1.1 Nomenclature Changes

The terms Regulation and Contingency have been introduced to more accurately reflect the service being provided.

The Regulation service is required to control frequency variations caused by load and intermittent generator fluctuations.

The Contingency service is required to control frequency variations caused by the unforeseen trip of a generator.

The terms Stage 1 and Stage 2 spinning reserve are no longer used

1.2 Introduction

Ancillary Services comprises two components:

- Regulation
- Contingency

Regulation

Load demand changes are uncontrollable by their nature and arise from customers changing their consumptions to meet their needs. Intermittent generator output changes occur due to changes in their fuel supply and their conversion process. The major generation types in this class are wind and solar powered generators.

Changes in demand and output cause a change to the system frequency which must be corrected by adjusting the outputs of controllable generators to return the frequency to within acceptable limits.

The generator outputs that can be controlled are those of partially loaded generators that are synchronised to the system and can change outputs in response to either automatic or manual frequency control signals. It should be noted that this function can not be performed by interruptible loads.

The SWIS currently requires a Regulation service of +/- 25,200 kW to ensure the frequency is maintained within acceptable limits for the majority of the time. This service is designed to compensate for 99.9% of load/intermittent generator demand/output variations over a short time frame. Specifically it is measured as the variance of one minute average readings about a 30 minute rolling average.

It should be noted that the capacity of intermittent generators expected to be operating in 2004/05 is minimal, however as more intermittent generators are connected to the SWIS the Regulation service requirement is likely to increase.

Contingency

Occasionally controllable generators do not behave in a controlled manner. These are generally

- Trips, where a generator will disconnect automatically to protect itself due to a failure within the generator or in response to abnormal system conditions.

- Failure-to-start, where a generator can not be started and synchronised at the required time due to an internal failure of the generator

In some case intermittent generators may also trip to protect themselves, causing a rapid reduction in generation output.

Such events cause a fall in the system frequency that must be arrested by increasing the output of reserve generators for a failure to start event or increasing the output of reserve generators and/or disconnecting interruptible loads for a trip event. Interruptible loads are loads contracted to be shutdown without notice upon a fall in system frequency.

The system currently requires a Contingency service of 70% of the output of the largest generating unit on the system. This is therefore dependent on the output of Collie and is generally 210 MW from morning to midnight and 140 MW for the remainder.

A portion of the first part of the Contingency service is automatically supplied from the generators providing the Regulation service.

1.3 Capital Costs of Providing Regulation

The capital cost of providing Regulation is based on the need to install suitable generation capacity to provide this service. It should be noted that the capacity cost is incurred to provide the service in the raise direction. The service in the lower direction is met by generation capacity installed to meet load needs. The cost is based on the annualised capital cost of installing open cycle gas turbines with the parameters listed in Table E1.

Table E1 Open Cycle Gas Turbine Costs

Frame 9 GT @	$583 per kW
O&M cost	$2.92 per kW / year
Economic life	15 years
Cost of capital	7% nominal after tax
Escalation rate	2.5% per year
Annual Cost	67.47 $/kW/year

The capital cost in $/kW is effectively the capital cost in the 2003/04 Price

Publication escalated by 2.5%

The capital cost of Regulation is the quantity multiplied by the rate

C_{REGCAP} $= Q_{REGCAP} \times C_{CREGCAP}$
$= 25{,}200 \times 67.47$
$= \$1{,}700{,}000$

C_{REGCAP} is the Annual Capital Cost of Regulation (in $)

Q_{REGCAP} is the Regulation Quantity (in kW)

$C_{CREGCAP}$ is the Annual Capital Cost of Regulation (in $/kW)

1.4 Operating Costs of Providing Regulation and Contingency and allocation between Regulation and Contingency

The major operating costs associated with providing Regulation are

- *Energy cost of deloading generating units*

  When a generating unit deloads to provide Regulation and Contingency services it runs at a sub-optimal point on its operating curve, resulting in a reduction in conversion efficiency.

- *Energy cost of out of merit generation*

  Providing Regulation and Contingency services incurs additional energy costs because generating plant lower in the merit order must be dispatched.

- *Interruptible load costs*

  A portion of the Contingency service is supplied by interruptible load. The cost of providing interruptible load is equivalent to the cost that otherwise would have been provided by partially loaded generators providing the same service.

The forecast annual operating cost of providing 140/210 MW of spinning reserve in 2004/05, based on the additional fuel consumed for a 1% reduction in system efficiency is $17,461,000, calculated as follows:

CSR140/210	$= SL \times (1/E_{with\ SR} - 1/E_{without\ SR}) \times FP \times Conv$
	$= 12,780 \times (1/0.31 – 1/0.32) \times 3,760 \times 3.6$
	= $17,461,000

where:

CSR140/210	is the annual operating cost (in $) of extra fuel consumed in providing 140 MW and 210 MW of spinning reserve taken as a 1% reduction in system efficiency.
SL	is the forecast system customer load for 2004/05 (12,780 GWh)
E_{withSR}	is the system efficiency if spinning reserve is provided (31%)
$E_{withoutSR}$	is the system efficiency if no spinning reserve is provided (32%)
FP	is the delivered fuel price ($3,760/TJ)
Conv	is the energy conversion between GWh and TJ (3.6)

The incremental costs of providing spinning reserve are:

AVE-OP	= CSR140/210 / (140 x H140 +210 x H210)
	= $17,461,000 / (140 x 2,760 + 210 x 6,000)
	= $10.61/MW.hour

CSR45	= AVE-OP x 45 x8760
	= $4,181,000

CSR140	= AVE-OP x 95 x 8760
	= $8,826,000

CSR210	= AVE-OP x 70 x H210
	= $4,454,000

where:

CSR45	is the total annual cost (in $) of providing an initial 45 MW of spinning reserve.
CSR140	is the total annual cost (in $) of providing an additional 95 MW of spinning reserve.
CSR210	is the total annual cost (in $) of providing an additional 70 MW of spinning reserve.

H140 is the forecast operating hours at 140 MW of spinning reserve in 2004/05

H210 is the forecast operating hours above 140 MW of spinning reserve in 2004/05

The operating cost of the first 45 MW is allocated across the Regulation and Contingency services as follows:

C_{REGOPG} = 25.2 / (25.2 + 45) x CSR45
= 1,501,000

C_{CONT45} = 45 /(25.2 + 45) x CSR45
= 2,680,000

1.5 Regulation Service Total Costs and Allocation between Loads and Intermittent Generators

The total cost of providing Regulation for 2004/2005 is:

C_{REGTOT} = C_{REGCAP} + C_{REGOPG}
= 1,700,000 + 1,501,000
= 3,201,000

where:

C_{REGTOT} is the total annual cost (in $) of providing Regulation

C_{REGCAP} is the annual capital cost (in $) of providing Regulation.

C_{REGOPG} is the annual operating cost (in $) of providing Regulation.

The cost allocation between loads and intermittent generators is based on the variations in demand and output over a short time frame. Specifically it is measured as the variance of 1 minute average readings about a 30 minute rolling average. The fluctuations are assumed to be independent and so the total variation squared is equal to the sum of the individual variances

Q_{REGTOT} $=\sqrt{(Q_{REGLOAD}^2 + Q_{REGINTGEN}^2)}$
$=\sqrt{(25,000^2 + 3,000^2)}$
=25,200

Where

Q_{REGTOT} is the total regulation quantity (in kW)

$Q_{REGLOAD}$ is the regulation quantity for loads (in kW)

$Q_{REGINTGEN}$ is the regulation quantity for intermittent generators (in kW)

The cost of the Regulation service is apportioned between loads and intermittent generators based on the quantity of each Regulation service compared to the total Regulation Service requirement

$$C_{REGLOAD} = Q_{REGLOAD}^2/(Q_{REGLOAD}^2 + Q_{REGINTGEN}^2) * C_{REGTOT}$$

$$= 25{,}000^2/(25{,}000^2 + 3{,}000^2) \text{ x } \$3{,}201{,}000$$

$$= 3{,}156{,}000$$

$$C_{REGINTGEN} = Q_{REGINTGEN}^2/(Q_{REGLOAD}^2 + Q_{REGINTGEN}^2) * C_{REGTOT}$$

$$= 3{,}000^2/(25{,}000^2 + 3{,}000^2) * \$3{,}201{,}000$$

$$= 45{,}000$$

Where

$C_{REGLOAD}$ is the cost of regulation allocated to loads (in $)

$C_{REGINTGEN}$ is the cost of regulation allocated to intermittent generators (in $)

1.6 Regulation Prices to Loads And Intermittent Generators

The Regulation cost for loads (in cents/kWh) is the total annual cost to loads as a function of the total system customer consumption.

$$P_{REGLOAD} = C_{REGLOAD} / SL$$
$$= 3{,}156{,}000 \text{ x } 100 /(12{,}780 \text{ x } 1{,}000{,}000)$$
$$\mathbf{= 0.025 \text{ cents} + .002 \text{ cents GST /kWh}}$$

where:

$P_{REGLOAD}$ is the Regulation Price (in cents/kWh) to loads

$C_{REGLOAD}$ is the Regulation Cost (in $) to loads.

SL is the total system customer load (in GWh)

Loads are therefore charged for Regulation based on their individual contract maximum demands. This charge is not explicit, but is included in the Network Tariffs.

The Regulation price for intermittent generators (in \$/MW) is the total annual cost as a function of the total system intermittent generation declared sentout capacity (DSOC).

$P_{REGINTGEN}$ = $C_{REGINTGEN}$ / $DSOC_{TOT}$
= 45,000/22
= **\$2,066 + \$207 GST /MW/year**

where:

$P_{REGINTGEN}$ is the Regulation Price (in \$/MW) to intermittent generators.

$C_{REGINTGEN}$ is the Regulation Cost (in \$) to intermittent generators.

$DSOC_{TOT}$ is the total system intermittent declared sentout capacity (in MW)

For intermittent generators with an installed capacity of less than 10MW a concession is made. Their Regulation Prices are

For installed capacity >= 5 MW and < 10 MW, one third of the standard price

\$689 + \$69 GST /MW/year

For installed capacity < 5 MW the same as the regulation price for loads that is

0.025 cents + 0.002 cents GST /kWh

1.7 Contingency Service Total Costs and Allocation between Levels of Contingency

The total costs of providing Contingency for 2004/2005 is:

C_{CONTOT} = C_{CONT45} + CSR140 + CSR210
= 2,680,000 + 8,826,000 + 4,454,000
= 15,960,000

where:

C_{CONTOT} is the total annual cost (in \$) of providing Contingency

C_{CONT45} is the annual operating cost (in \$) of proving the first 45MW of Contingency

CSR140 is the annual operating cost (in \$) of providing the next 95MW Contingency.

CSR210 is the annual operating cost (in \$) of providing the next 70MW Contingency

It should be noted that there is no capital cost associated with the Contingency service.

1.8 Contingency Cost Allocation and Prices to Generators

Generator spinning reserve prices are shown in Table G2 below (at the end of this section), derived using the following methodology.

The spinning reserve prices for generators (in $/hour) are a function of the incremental costs to provide spinning reserve to each MW block of generation, and the total estimated running hours for generators in each of the blocks. The sizes of these blocks are based on typical groupings of generator unit maximum net MW outputs. Refer to Table G1 below for details.

Note that the total size of Block 2 is the sum of the two sub- blocks: Block 2210 and Block 2140, ie 126 MW – 200 MW, equalling 75 MW.

The incremental cost for each of the generation blocks is calculated in Table E2 below:

TABLE E2

Block Number	Block Size (MW)	Block Range (MW)	Incremental Cost Calculation ($)	Incremental Load ($)
1	100	201 – 300	(10/70) x CSR210	IC_1
2_{210}	60	141 – 200	(60/70) x CSR210	IC_{2210}
2_{140}	15	126 – 140	(15/95) x CSR140	IC_{2140}
3	60	66 – 125	(60/95) x CSR140	IC_3
4	20	46 – 65	(20/95) x CSR140	IC_4
5	45	0 - 45	C_{CONT45}	IC_5

where:

C_{SRG} $= IC_1 + IC_{2210} + IC_{2140} + IC_3 + IC_4 + IC_5$, and

IC_j is the incremental cost (in $) of providing spinning reserve to generating units in block j, for j = 1,3,4 & 5.

IC_{2140} is the incremental cost (in $) of providing 140MW of spinning reserve to generating units in Block 2.

IC_{2210} is the incremental cost (in $) of providing 210MW of spinning reserve to generating units in Block 2.

Note that Blocks 3 to 5 are covered by the incremental costs of providing up to 140MW of spinning reserve, and Block 1 is covered by the incremental cost of providing 210MW of spinning reserve. However, generators in Block 2 are partially covered by the incremental costs of providing 140MW and partially covered by the incremental cost of providing 210MW of spinning reserve. Hence the need to divide Block 2 into two sub-blocks to equitably recover the costs associated with both levels of spinning reserve coverage.

The principle used to determine generator spinning reserve prices ensures that generator users are only charged for the level of spinning reserve that they create a need for. The larger the generating unit the greater the spinning reserve price. Therefore, calculated first is the individual price element for each of the blocks as a function of the incremental block costs and generator running times, as follows:

$SRP_{Block\ 1} = IC_1 / RT_1$

$SRP_{Block\ 2_{210}} = IC_{2_{210}} / (RT_1 + RT_{2_{210}})$

$SRP_{Block\ 2_{140}} = IC_{2_{140}} / (RT_1 + RT_{2_{140}} + RT_{2_{210}})$

$SRP_{Block\ 3} = IC_3 / (RT_1 + RT_{2_{140}} + RT_{2_{210}} + RT_3)$

$SRP_{Block\ 4} = IC_4 / (RT_1 + RT_{2_{140}} + RT_{2_{210}} + RT_3 + RT_4)$

$SRP_{Block\ 5} = IC_5 / (RT_1 + RT_{2_{140}} + RT_{2_{210}} + RT_3 + RT_4 + RT_5)$

where:

$SRP_{Block\ j}$ is the spinning reserve price element (in \$/hour) applicable to block j, for j = 1,3,4 & 5; and 2_{210} & 2_{140}

RT_j is the total annual running time (in hours) for all generator units in block j, for j = 1,3,4 & 5

$RT_{2_{140}}$ is the running time (in hours) during which those generators in block 2 are covered by 140MW of spinning reserve.

$RT_{2_{210}}$ is the running time (in hours) during which those generators in block 2 are covered by 210MW of spinning reserve.

Based on the principle of charging generators for all those levels of spinning reserve that they create a need for, the smallest generators in block 5 will only be charged at the rate calculated for their particular block. However the rate or price for a larger generator, up to those included in block 1, will be determined by adding the rate for its particular block to the progressive sum of the rates for all subordinate blocks.

The total spinning reserve prices for each of the generator blocks are, therefore, calculated as follows:

$SRP_{Gen1} = SRP_{Block\ 1} + SRP_{Block\ 2_{210}} + SRP_{Block\ 2_{140}} + SRP_{Block\ 3} + SRP_{Block\ 4} + SRP_{Block\ 5}$

$SRP_{Gen2_{210}} = SRP_{Block\ 2_{210}} + SRP_{Block\ 2_{140}} + SRP_{Block\ 3} + SRP_{Block\ 4} + SRP_{Block\ 5}$

$SRP_{Gen2140}$ = $SRP_{Block\ 2140}$ + $SRP_{Block\ 3}$ + $SRP_{Block\ 4}$ + $SRP_{Block\ 5}$

SRP_{Gen3} = $SRP_{Block\ 3}$ + $SRP_{Block\ 4}$ + $SRP_{Block\ 5}$

SRP_{Gen4} = $SRP_{Block\ 4}$ + $SRP_{Block\ 5}$

SRP_{Gen5} = $SRP_{Block\ 5}$

The price for generators in Block 2 is simplified by averaging its two (140/210) component prices as follows:

SRP_{Gen2} = $[(SRP_{Gen2140} \times RT_{2140}) + (SRP_{Gen2210} \times RT_{2210})] / [RT_{2140} + RT_{2210}]$

where:

SRP_{Genj} is the total spinning reserve price (in $/hour) for a generating unit in block j, for j = 1, 3, 4 and 5.

$SRP_{Gen2210}$ is the component spinning reserve price (in $/hour) associated with providing those generators in block 2 with 210MW of spinning reserve.

$SRP_{Gen2140}$ is the component spinning reserve price (in $/hour) associated with providing those generators in block 2 with 140MW of spinning reserve.

The resulting generator spinning reserve prices are provided below in Table E3. Note that the smaller, <10 MW, generators in the first group are not charged for spinning reserve.

Table E3 Contingency Prices for different generator sizes:

GENERATOR UNIT MAXIMUM NET OUTPUT (MW)	PRICE ($/h)
<10	0.00 + 0.00 GST
10 - 45	8.34 + 0.83 GST
46 - 65	24.75 + 2.47 GST
66 - 125	92.50 + 9.25 GST
126 - 200	177.76 + 17.78 GST
200 - 330	268.57 + 26.86 GST
>330	POA

POA is price on application

Newer intermittent generators tend to be installed in large groups of small generators (<3 MW each). However sometimes it is necessary to shutdown all the generators simultaneously, as a consequence of which it is necessary to base the price for the contingency service on the aggregate capacity. On the other hand wind generators operate below full output for most of the time and the contingency service charge is based on the average of output.

Simultaneous shutdown for a wind farm may occur from protection from high wind conditions, generator shutdown due to voltage dips and wind farm disconnection due to loss of a radial network connection.

In cases the where shutdown can demonstrated to take place gradually over 15 minutes or more, the contingency service charge may be waived.

1.9 Interruptible Load Prices

Interruptible load is used for the Contingency service. It can be provided by both Western Power and independent Users.

If a proposal to provide interruptible load satisfies a number of technical and commercial criteria, the supplier will be paid the Interruptible Load Price (ILP), calculated below, for providing this service.

The purchase price for interruptible load (in \$/MW) is the average operating cost per MW of Contingency service. This price is calculated as follows:

C_{CONTOT} = \$15,960,000

$Q_{CONTAVE}$ = $[(140MW \times H_{140}) + (210MW \times H_{210})] / [H_{140} + H_{210}]$
= $[(140 \times 2{,}760) + (210 \times 6{,}000)] / [2{,}760 + 6{,}000]$
= 188MW

$P_{INTLOAD}$ = C_{CONTOT} / Q_{CONAVE}
= \$15,960,000 / 188
= **\$85,000 + \$8,500 GST /MW/year**

note: price is rounded for convenience

where:

$P_{INTLOAD}$ is the annual interruptible load purchase price (in \$/MW) paid for supply of the interruptible load service.

C_{CONTOT} is the operating cost (in \$) of providing Contingency service

$Q_{CONTAVE}$ is the average quantity of Contingency reserve by weighting the number of hours of Contingency reserve at 140MW and 210MW (in MW)

The interruptible load payment is based on the Interruptible Load Price multiplied by the quantity of interruptible load provided during the on-peak hours (0800 hours to 2200 hours on weekdays).

Note: Supply Of Interruptible Load

Western Power's Network Business currently performs the function of procuring interruptible load from Load Customers and/or Retailers (including both independent Retailers and Western Power Retail) and on-selling it as an integral component of the spinning reserve service to all generator users.

Currently the system can accept no more than 80 MW of interruptible load. From time to time customers' interruptible load contracts will expire. At that time, Western Power Networks will procure additional interruptible load to meet system needs.

The customer and/or their new retailer would then be entitled to receive the Interruptible Load payment.

2. STANDBY GENERATION CAPACITY - METHODOLOGY AND SERVICE PRICES

2.1 Introduction

As a condition of access Independent Power Producers (IPP) are required to make standby arrangements. This can be in the form of contractual arrangements with other IPPs with spare generation or with Western Power. An option for an IPP would be to contract with associated load for curtailment thereby avoiding the need to contract for standby.

2.2 Methodology Change

Previous standby prices were based on the provision of 30 days of standby for both maintenance and unplanned outages. The introduction of Top-Up and Spill provides for the exchange of energy during maintenance of a generator. Standby services are now provided for only unplanned outages. Additionally the installation of intermittent generators has led to a review of the standby pricing methodology. The option to change between energy balancing and Top-Up and Spill makes the retention of the 30 day scheme, although desirable, no longer valid.

2.3 Standby Conditions

Western Power may offer to supply standby capacity on the following basis:

Standby capacity is applicable to supply loads resulting from failures of generators of less than 100 MW Declared Sent Out Capacity (DSOC) for each single SWIS connection point. It must be noted that for cases above 100 MW the Standby capacity for the whole DSOC must be separately negotiated, not just that part above 100MW. A 100 MW threshold is imposed as this is a significant part of the standby capacity and also needs special consideration in terms of accessing the required fuel to supply a shortfall of this size.

Should the standby capacity usage exceed a contracted Standby Generation Reservation quantity, an excess fee will be charged.

The supply reliability of loads covered by standby will be equal to that of other customers supplied by the system at the time.

2.4 Standby Charges

There are two standby charges that may apply:

- Standby Capacity charge; and
- Excess Standby Generation Capacity charge.

Standby Capacity charge will apply on an annual basis and will be charged according to the Standby Generation Reservation quantity multiplied by the Standby Price for the year. The Standby Generation Reservation amount is at the discretion of the IPP, however it is often set as the total CMD of the IPP loads plus a reserve margin minus the firm capacity of the IPP generators. This philosophy is based on the need for a Retailer to balance "Capacity Credits". The Capacity Credit cost is determined by annual cost of an open cycle gas turbine as given in Table E1. The 2004/05 Capacity Credit Cost (CCC) is $67.47/kW/year.

The reserve margin is 20% (as per GSR for the first Reserve Capacity Auction – Reserve Margin above 10% POE is 304 MW, a Reserve Margin of 9% (= 304/3528). In addition the 10% POE load above the 50% POE load gives a reserve margin of 10% 3528/3218. Hence Capacity above normal peak is 109% times 110%= 120%)
For a dispatchable generator the firm capacity is calculated as:

DSOC x (1 - FOR)

Where FOR is the forced outage rate. In the absence of FOR performance a value of 4% shall be used.

For an intermittent generator the firm capacity is calculated as

DSOC x SPPF

Where SPPF is the System Peak Performance Factor. It is the measured percentage output the intermittent generator has during system peak demand. In the absence data on SPPF performance a value of 23% shall be used. This is based on the firm capacity attributed to the system intermittent generators in the 2004 Generation Status Review

The Standby Capacity Charge for a dispatchable generator is

STCC = ((DSOC x (1-FOR)) – (SGR x (1 + Reserve Margin))) x CCC

Where:

STCC (in $) is the Standby Capacity Charge

DSOC (in kW) is the Declared Sentout Capacity

FOR is the Forced Outage Rate

SGR (in kW) is the Standby Generation Reservation

Reserve Margin is 20%

CCC (in $/kW) is the Capacity Credit Cost ($67.47/kW/year)

The Standby Capacity Charge for an intermittent generator is

STCC = ((DSOC x (SPPF)) – (SGR x (1 + Reserve Margin))) x CCC

Where:

STCC (in $) is the Standby Capacity Charge

DSOC (in kW) is the Declared Sentout Capacity

SPPF is the System Peak Performance Factor

SGR (in kW) is the Standby Generation Reservation

Reserve Margin is 20%

CCC (in $/kW) is the Capacity Credit Cost ($67.47/kW/year)

The Standby Capacity Price is Standby Capacity Credit Cost/Standby Generation Reservation

SCP = STCC/SGR

Where:

SCP (in $/kW) is the Standby Capacity Price

Note a minimum of $16.19 + $1.62 GST /kW/year applies to the Standby Capacity Price.

The annual Standby Capacity Charge, excluding energy charges, are calculated as follows:

SCC = SCP x SGR

where:

SCC (in $) is the Standby Capacity Charge;

SCP (in $/kW) is the Standby Capacity Price;

SGR (in kW) is the Standby Generation Reservation for the group of connections in respect of the standby generation capacity agreement.

Example Calculations

An IPP has a contracted load with a demand at system peak of 10,000 kW and a contracted Dispatchable generator with an installed capacity of 10,000 kW.

The IPP elects to have a Standby Generation Reservation of 10,000 kW.

The Load gives rise to an obligation to purchase 10,000 x (1 + 20%) = 12,000 kW of "capacity credits"

The Generator gives rise to the ability to supply 10,000 x (1 – 4%) = 9,600 kW of "capacity credits"

The IPP needs to purchase 12,000 –9,600 kW = 2,400 kW of capacity credits

The Capacity Credit cost is 2,400 kW x $67.47/kW/year = $161,928

The annual Standby Capacity price from Western Power is 161,928/10000 = $16.19/kW and the annual Standby Capacity charge is $161,928

An IPP has a contracted load with a demand at system peak of 10,000 kW and a contracted Intermittent generator with an installed capacity of 30,000 kW.

The IPP elects to have a Standby Generation Reservation of 10,000 kW.

The Load gives rise to an obligation to purchase 10,000 x (1 + 20%) = 12,000 kW of "capacity credits"

The Generator gives rise to the ability to supply 30,000 x 23% = 6,900 kW of "capacity credits"

The IPP needs to purchase 12,000 –6,900 kW = 5,100 kW of capacity credits

The Capacity Credit cost is 5,100 kW x $67.47/kW/year = $344,097

The annual Standby Capacity price from Western Power is 344,097/10,000 = $34.41/kW and the annual Standby Capacity charge is $344,097.

The annual standby price for an intermittent generator will vary according to the SPPF, the level of contracted load and the installed capacity of the generator.

Excess Standby Generation Charge will apply where demand exceeds the agreed Standby Generation Reservation in addition to energy charges for the energy usage. This is known as an excess demand and occurs when the loss factor adjusted demand exit rate is greater than the sum of the loss factor adjusted demand entry rate and standby generation reservation in any half-hour.

An excess demand period of 336 half hours (one week) in duration is initiated by the occurrence of an excess demand.

The charge payable will be calculated based on the maximum excess demand occurring during each excess demand period.

This charge is detailed in regulation 23 of the Electricity Transmission Regulations 1996 and regulation 25 of the Electricity Distribution Regulations 1997. A summary is given below

ESCC = Ei x ESGF

where:

ESCC (in $) is the Excess Standby Generation Capacity Charge;

Ei (in kW) is the highest excess demand for any half hour falling within the excess demand period;

ESGF (in $/kW) is the excess standby generation capacity fee

The ESGF for 2004/05 is $20 +$2 GST /kW/excess demand period

3. ENERGY BALANCING SERVICE PRICES

Balancing energy is used to settle mismatches between entry and exit points. An Independent Power Producer (IPP) may elect to be on the Energy Balancing Scheme for this purpose. Alternatively an IPP may elect to be on the Top-up and Spill scheme (refer section 4) for this purpose.

A description of the "Energy Balancing Scheme" is published on Western Power's web site at:

http://www.westernpower.com.au/html/networks/network_access/balancing_prices/network_balancing_prices_description.html

The scheme consist of 2 sets of prices

- Half hour prices
- Monthly prices

Half hour prices

These are half hourly buy and sell prices for settlement of energy outside a defined permitted tolerance on a half hourly basis.

Monthly average prices

These are buy and sell prices for settlement of energy within the balancing tolerance on a monthly basis.

The prices are published on Western Power's web site at:

http://www.westernpower.com.au/html/networks/network_access/balancing_prices/network_balancing_prices_weekly.html

4. TOP UP AND SPILL ENERGY SERVICE PRICES

Top up and spill energy is used to settle mismatches between entry and exit points. An IPP may elect to be on the Top Up and Spill Scheme for this purpose. Alternatively an IPP may elect to be on the Energy Balancing scheme (refer section 3) for this purpose.

Additionally the Top Up and Spill scheme allows trading of energy with Western Power

A description of the "Top Up and Spill Scheme" is published on Western Power's web site at:

http://www.westernpower.com.au/html/networks/network_access/balancing_prices/TUAS_balancing_prices_description.html

The scheme consist of 2 sets of prices

- Balancing prices
- Trading prices

Balancing prices

These are half hourly buy and sell prices for settlement of energy inside a defined permitted tolerance on a half hourly basis.

Trading prices

These are buy and sell prices for settlement of energy based on an IPP specified nomination in advance.

The prices are published on Western Power's web site at:

http://www.westernpower.com.au/html/networks/network_access/spill_prices/index.html

5. INTERMITTENCY SERVICE PRICES

5.1 Introduction

The output of an Intermittent generators can not be accurately predicted over the medium term, that is one day in advance. TUAS energy pricing is based on marginal or nominated energy interchanges with Western Power based movements in the fuel costs incurred. Additional costs in the form of generator startup costs are also incurred whilst maintaining generation equal to demand in a system where a large part of the load is comprised of intermittent generators. The intermittency charge together with the TUAS energy prices recovers the non-capital costs of the TUAS regime. The regime is provided on an economically cost neutral basis to Western Power.

5.2 Methodology

Western Power uses a spreadsheet based model to approximate the extra generator movements that will occur with a large percentage of intermittent generators placed on the SWIS. The extra number of starts multiplied by the start costs give the extra costs to be recovered by the intermittency charge.

5.3 Charges and Prices

Intermittency charge will apply on an annual basis and will be charged according to the Declared Sentout Capacity quantity multiplied by the Intermittency Price for the year.

The annual Intermittency Charge, is calculated as follows:

ICC = ICP x DSOC

where:

ICC (in $) is the Intermittency Capacity Charge;

ICP (in $/MW) is the Intermittency Capacity Price;

DSOC (in MW) is the Declared Sentout Capacity.

The ICP for 2004/05 is $1,870 + $187 GST /MW/year.

For intermittent generators with an installed capacity of less than 10MW a concession is made. Their Intermittency Prices are

For installed capacity >= 5 MW and < 10 MW, one third of the standard Intermittency price

$623 +$62 GST /MW/year

For installed capacity < 5 MW

0.000 cents + 0.000 cents GST /kWh