Appendix D

BRW Report

Burns and Roe Worley, *Directlink, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*, May 2004

Directlink Joint Venture

(Emmlink Pty Limited & HQI Australia Pty Limited Partnership)

Directlink

Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC

5th May 2004

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
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DISCLAIMER

BRW has carried out this work to select and assess alternative projects that are intended to be used as an input to an application for conversion of the Directlink DC interconnector to a regulated asset. In conducting the work, BRW has relied upon information provided by a number of sources including The Allen Consulting Group, the Directlink Joint Venture and statements from relevant electricity industry planning and regulatory authorities and price quotations from equipment suppliers.

BRW believes that the information provided was true and correct at the time the work was carried out. BRW has verified the completeness and accuracy of the data provided to the extent this was possible within the time and budget constraints of the project. However, BRW recognises that within these constraints it was not possible to gather and assess all information available in relation to Queensland – NSW interconnector planning and the related regional power system issues. BRW has offered opinions on the relevant services to be considered in the selection and assessment of alternative projects that are intended to form the basis of the Directlink conversion application. Costs and benefits estimates have been prepared based on the available information which has been sought by BRW from utilities and suppliers during the conduct of this project. These cost estimates are considered adequate for the purposes of this conversion application.

EXECUTIVE SUMMARY

The Directlink Joint Venture wishes to make an application to the Australian Competition and Consumer Commission (ACCC) for the Directlink DC interconnector between Queensland and New South Wales to become a regulated interconnector.

Scope of this report

The Directlink owners have engaged The Allen Consulting Group (ACG) to prepare the subject application. In turn, ACG has engaged Burns and Roe Worley (BRW) to prepare a report which covers the following areas:

(i) Define in detail Directlink's network service in terms of the extent to which it:

- enables the network to satisfy Schedule 5.1 of the National Electricity Code and other network performance requirements, and
- provides inter-regional flows.

(ii) Select, cost and assess alternative projects for the purpose of applying the Regulatory Test.

(iii) Provide detailed information on the nature, purpose, timing and costs of expected network augmentations with and without each of the alternatives and calculate the network deferral benefits of the alternative projects in accordance with the Regulatory Test using discounted cash flow calculations.

This report is intended to form an important input to the ACG work of preparing the Application to the ACCC.

Directlink is a DC transmission interconnection that connects the Queensland 110 kV system at Terranora in far north-east New South Wales with the New South Wales 132 kV system at Mullumbimby, approximately 40 km south of Terranora. Directlink comprises of ABB's HVDC Light® technology with converter stations sited at Bungalora and Mullumbimby substations. Each AC/DC converter station has a nominal 3 x 60 MW rating and the DC underground link has been constructed using three parallel cable bi-polar circuits. A 110 kV AC underground cable connects Bungalora with Terranora substation.

Approach

BRW's approach is designed to align with clause 5.6.6(b)(1) of The National Electricity Code[1] (Code), which requires that an application notice must describe:

(i) the proposed *new large network asset*;

(ii) the reasons for proposing to establish the *new large network asset* (including, where applicable, the actual or potential *constraint* or inability to meet the *network* performance

[1] Clause 5.6.6(b)(1) of the National Electricity Code.

requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction*, including *load* forecasts and all assumptions used); and

(iii) all other reasonable *network* and non-network alternatives to address the identified *constraint* or inability to meet the *network* performance requirements identified in paragraph (ii) above. These alternatives include, but are not limited to, *interconnectors*, *generation* options, demand side options, *market network service* options and options involving other *transmission* and *distribution networks*;

Accordingly, BRW has prepared descriptions of:

- Directlink and the network service it can provide as a regulated transmission asset;
- Network constraints that are emerging in the Gold Coast and the far north eastern NSW areas, which in the absence of Directlink, would require TransGrid and Powerlink to undertake reliability network augmentations to meet the network performance requirements set out in Schedule 5.1 of the National Electricity Code and state codes/regulations including S34.2 of the Electricity Act (Queensland) 1994, and S6.2 of Transmission Authority No. T01/98;
- The selection and assessment of a number of alternative projects that would be "relevantly substitutable" with Directlink as a regulated asset.[2]

BRW has described Directlink's network service in terms of its real power transfer capability, its reactive power and voltage control capability, its ability to provide network support, its ability to facilitate greater inter-regional flows between the New South Wales and Queensland regions, and its ability to enhance the transient, voltage and oscillatory stability and security of the power system.

In selecting and assessing the alternative projects, BRW has carefully considered the technical feasibility, costs and benefits of each project component. BRW considered a wide range of projects including AC and DC transmission alternatives that incorporated, as technically and economically appropriate, phase shifting transformers, switched shunt capacitors, SVCs, synchronous condensers, transmission augmentations and upgrades, demand side management and new generation. In developing the alternatives, consideration has also been given to the need for the projects to secure environmental and planning approval.

BRW costed the above alternatives as if they were to be constructed under a competitively-priced all-inclusive EPC contract. BRW used data provided by equipment suppliers and NSPs, which was supplemented and verified against BRW's in-house costing data, and included an industry standard level of contingency and profit/overhead to derive a project cost based on an EPC contract price. In determining the present value of the total costs of each of the alternatives, BRW has also estimated "interest during construction" (IDC) that would be borne by the principal or the EPC contactor (which, in the later case would be included in the contract price) and the cost of "operations and maintenance" of the project.

[2] ACCC, "Decision: Murraylink Transmission Company Application for Conversion and Maximum Allowable Revenue", 1 October 2003, p. 38.

BRW then determined the extent to which Directlink and each of the alternative projects has the capability to defer reliability network augmentations in the Gold Coast and the far north eastern NSW areas up to the year 2020.

Summary of findings

The Directlink asset itself has an as-tested power transfer capability of 174.9 MW at the receiving end. Unlike an AC link, the power transfer capability of a DC link can be controlled independently of the generation scheduling in the interconnected regions and independently of the flows on other interconnectors. Nevertheless, the capability of Directlink can be limited at times by network constraints in the vicinity of Directlink. Powerlink, Country Energy and TransGrid have identified a number of emerging transmission constraints in the far north east NSW and Gold Coast areas. These network constraints also presently limit Directlink's full capability. The constraints in NSW are the thermal constraints on the 132 kV lines between Armidale and Lismore for loss of 330kV Line 89 and voltage constraints on the NSW lower north coast. An emergency tripping scheme and SVC is installed at Lismore to cater for the outage of a critical network element. The network constraints in Queensland are thermal constraints on the 110 kV lines between Mudgeeraba and Terranora and between Beenleigh and Molendinar, voltage stability in the 110 kV Gold Coast network and thermal constraints on the 275 kV lines between Swanbank and Mudgeeraba/Molendinar for loss of 275 kV line 805 or 806. An emergency tripping scheme is installed at Mudgeeraba to cater for the outage of a critical network element.

As part of its modelling, BRW has assessed that Directlink in its current form with the emergency control and tripping schemes has very little ability to defer major transmission augmentations, particularly with constraints existing in both NSW and Queensland. BRW has identified that Directlink, with post-contingent support, could defer planned major transmission augmentations by a number of years if supplemented with some power factor correction in the Gold Coast. Implementation of post-contingent support for Directlink would require some capital expenditure that is justified by the benefit of deferring other major reliability augmentations. BRW has defined an Alternative 0 project in this report to reflect this recommended enhancement to Directlink.

BRW has developed a short-list of alternative projects and considered whether they are relevantly substitutable with Directlink for the purpose of applying the Regulatory Test. These alternative projects are listed below:

0. Modified Directlink;
1. DC Link using HVDC Light® (or equivalent) technology;
2. DC link using conventional HVDC technology;
3. AC link using a phase shifting transformer;
4. AC link using a conventional auto-transformer;
5. State based AC augmentations in NSW and Queensland;
6. Demand Management and / or Embedded Generation.

Alternative 0 is Directlink with some additional capital expenditure to provide post-contingent network support services and reactive support to the Gold Coast.

Alternatives 1 and 2 are DC links with similar technical performance as Alternative 0, and BRW has found they would provide similar network deferral benefits. The major difference is in the use of different converter technologies. This results in dissimilar capital costs for each of these alternative projects. The power flows on the DC alternative projects can be controlled independently of the flows on QNI.

Alternative 3 is an AC interconnector with a limited ability to control power flows between the Queensland and NSW regions by way of a phase shifting transformer. Unlike the DC alternative projects, the flows on Alternative 3 are related to the flows on QNI to some extent. Therefore the ability to transfer power between regions with this alternative is less than the DC alternative projects because of this dependence and the complementary need to use the phase shifting transformer tapping range capability for network support.

BRW has assessed that Alternatives 0 to 3 inclusive are feasible alternative projects for the purposes of applying the Regulatory Test.

Alternative 4 has been assessed by BRW as an unsatisfactory alternative project for the purposes of applying the Regulatory Test, despite being a typical AC interconnector. Alternative 4 provides no network augmentation deferral benefits because the power flows on Alternative 4 are not directly controllable and depend on the flows on QNI. The network constraints in the Gold Coast and far north east NSW regions are exacerbated under some QNI flow scenarios.

Alternatives 2, 3 and 4 all include a part-overhead transmission line between Mullumbimby and Terranora. The nature of this coastal area on the eastern Australian seaboard is very sensitive from an environmental and public/community perception perspective. BRW has assessed that the environmental and planning approval process would be one to two years longer for these part-overhead line alternatives. A conservative one year increase in the project time frame has been allowed for by the capital and IDC costs for these alternatives. Additional time would be required should a proponent attempt to obtain community acceptance for an all overhead transmission line in this locality, with an assessed little chance of a favourable end result. As a result of the environment and social issues identified, provision has been made for some tactical undergrounding of the transmission lines in environmentally sensitive areas where, based on expert advice from URS Australia, such undergrounding would be required by planning authorities. An independent expert review by ERM has supported the need for this approach. In comparison, Alternatives 0 and 1 are required to be totally underground because of the converter requirements.

Alternative 5 consists of augmentations in each state commencing around 2006. These augmentations align very closely with the TNSP augmentation plans and reflect the state based reliability driven augmentations that would be required in each state to support load growth. Alternative 5 only includes projects which could be potentially deferred by Directlink or the other alternative projects and as such, is used as the basis for determining the first tranche of deferment benefits.

BRW has assessed that Alternative 6 is not a feasible alternative on the basis of not being of sufficient size to make any impact on the load growth. The NSPs have already included planned demand-side and embedded generation schemes in their load forecasts, therefore the underlying growth is substantially greater. Alternative 6 would need to implement additional capacity above and beyond what is already planned. BRW does not believe this is practical and has therefore recommended that Alternative 6 not be included as an alternative project for the purposes of applying the Regulatory Test.

The present value of the costs of Directlink and the alternative projects (in Jan 2005 AUD) are summarised below:

COSTS	Capital	IDC	Life-cycle O&M	Total Cost
Directlink	$161.7M	n/a	$30.8M	$192.6M
Alternative 0	$170.4M	n/a	$30.8M	$201.2M
Alternative 1	$245.2M	$13.2M	$30.8M	$289.2M
Alternative 2	$182.2M	$11.8M	$30.8M	$224.8M
Alternative 3	$74.4M	$6.8M	$28.8M	$110.0M
Alternative 5	$205.4M	$14.8M	$33.9M	$254.1M

Note: Alternative 6 was not costed by BRW. Interest during construction life-cycle O&M and ancillary service costs in this table are based on a 9% commercial discount rate. The actual interest during construction (project financing costs) for Directlink and Alternative 0 are incorporated in their actual capital costs.

The difference in cost between Alternative 0 and Directlink is the additional capital expenditure required for Directlink to provide network support.

The deferment of reliability augmentations by Directlink and each of the other Alternative projects is presented in the table below.

DEFERMENT	Planned Augmentation			
	First Tranche ------ Alternative 5 ------		Second Tranche ------ Other Projects ------	
State Year	QLD 2005/6	NSW 2006	QLD 2014/15	NSW 2014
Alternative 0	5 years	7 years	4 years	3 years
Alternative 1	5 years	7 years	4 years	3 years
Alternative 2	5 years	7 years	4 years	3 years
Alternative 3	2 years	2 years	1 year	0 years

Note: Alternative 5 is a component of the deferred projects and is therefore not included in this table. The extent to which these deferments can be realised shall depend on the availability and reliability of each alternative project. BRW has assumed identical availability and reliability levels for all of the alternative projects, at levels typically observed for overhead transmission lines.

The first tranche of projects are similar to the projects defined by the network service providers within their planning horizon. The second tranche represent those projects proposed by BRW beyond the network service providers' planning horizon up to 2020. The deferments range from 0 years up to a maximum of 7 years. These deferment periods are based on a medium economic growth 50% POE load forecast projected up to 2020.

The benefits of reliability augmentation network deferment for the alternative projects are summarised below:

BENEFITS	**Present Value Deferment Benefit**
Alternative 0	$136.5M
Alternative 1	$136.5M
Alternative 2	$136.5M
Alternative 3	$42.7M
Alternative 5	$254.1M

Note: The deferment benefit of Alternative 5 is equal to the total cost of Alternative 5 – its benefit is effectively derived from the fact that, if built, it would permanently defer itself. This is consistent with the manner in which the deferment benefits of the other projects have been determined.

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1 INTRODUCTION

1.1 Description of the Directlink Asset

Directlink is a High Voltage Direct Current (HVDC) transmission link which interconnects the Queensland and NSW power grids. Directlink connects Terranora in NSW at the Queensland end of the link with Mullumbimby in NSW. Directlink comprises three parallel HVDC links between Mullumbimby and Bungalora (4 km south-west of Terranora) and a single 110 kV AC transmission link between Bungalora and Terranora.

The HVDC link uses ABB's HVDC Light® Technology. This technology was first introduced by ABB in 1997 and it is the most advanced HVDC technology commercially available. It has a number of technical advantages compared with other HVDC technologies. The HVDC links comprise of a converter station at Mullumbimby and a second converter station at Bungalora. The HVDC cables between Mullumbimby and Bungalora, a distance of 59 kilometres, are direct buried over part of this distance and in cable trays/ducts along a railway line for most of the route. The 4 kilometre long 110 kV AC link between Bungalora and Terranora is a conventional AC underground cable. Bungalora was established due to physical space and environmental limitations at Terranora.

Directlink is one of only two transmission links between NSW and Queensland. The other link is QNI (Queensland – NSW Interconnection), a double circuit 330 kV AC transmission link connecting Dumaresq substation in NSW with Bulli Creek substation in Queensland. Directlink operates in parallel with QNI.

1.2 The Present Project Defined

The Directlink's owners, represented by the Directlink Joint Venture Management Committee, wish to make an application to the ACCC for the Directlink DC interconnector between Queensland and New South Wales to become a regulated asset and provide "prescribed services" to the National Electricity Market (NEM).

The Directlink owners have engaged The Allen Consulting Group (ACG) to prepare the subject application. In turn, ACG has engaged Burns and Roe Worley (BRW) to prepare a report which covers the following areas:

(i) Define in detail Directlink's network service in terms of the extent to which it:

- enables the network to satisfy Schedule 5.1 of The Code and other network performance requirements, and
- provides inter-regional flows.

(ii) Select, cost and assess alternative projects for the purpose of applying the Regulatory Test including providing detailed advice on the relevant environmental issues.

(iii) Provide detailed information on the nature, purpose, timing and costs of expected network augmentations with and without each of the alternative projects so that ACG may calculate the network deferral benefits of the alternative projects in accordance with the Regulatory Test using discounted cash flow calculations.

1.3 Current and Emerging Network Constraints

Load growth in the far north east NSW network is presently between 2 and 3 percent and growth on the Gold Coast presently stands at between 4 and 5 percent. Over the years, this growth has resulted in greater network utilisation. Significant constraints are now emerging in these networks which need to be addressed within the next couple of years. The load on the Gold Coast and far north coast of NSW is mainly residential and light commercial load with most of this growth being in new property development and in the use of air-conditioners. The recent hot weather in south east Queensland has highlighted the strength of air-conditioning growth in this region with record electricity demands being observed. Despite the recent summer being abnormally hot, the demands have highlighted that underlying growth is strong and consistent in the area.

The need to augment the networks in both these areas is required to be able to support the loads in the near future, providing a reliable supply at acceptable voltage levels. Over the longer term, the growth is projected to continue reasonably steadily but falling to around 3 % for the Gold Coast and remaining around 2.5 % in the far north east of NSW by the end of the decade.

The TNSPs have prudent plans in place to augment their transmission networks. BRW has independently assessed that these augmentation plans need to be implemented at some time to support growth. As part of Directlink's conversion to a regulated asset, the Directlink owners are seeking to highlight Directlink's value to the transmission network as a potential provider of network support services that would allow deferral of some of the TNSP augmentation projects. This service would then take full advantage of existing infrastructure rather than making new investments.

Further details on the network elements involved in the emerging network constraints in the region are provided in Section 4 of this report.

2 DIRECTLINK'S NETWORK SERVICE QUANTIFIED

2.1 Definition of Services Provided by Directlink

Directlink's adequacy at providing a network service can be defined in terms of its ability to:

(i) transfer active power in both directions, namely from north to south and from south to north;

(ii) generate or absorb reactive power at each end of the link and provide voltage control;

(iii) provide network support to the Gold Coast and far north coast of New South Wales using (i) and (ii);

(iv) facilitate greater inter-regional flows between the New South Wales and Queensland regions using (i); and

(v) enhance the transient, voltage and oscillatory stability and security of the interconnected power system, particularly in NSW and Queensland.[3]

2.2 Directlink Services and Schedule 5.1 of the Code

In Schedule 5.1 of the National Electricity Code (the Code), the planning, design and operating criteria that must be applied by the Network Service Providers for transmission assets are described. To test that Directlink is able to assist the TNSPs in complying with The Code, each of the relevant Code sections are discussed below in relation to Directlink's network services.

S5.1.2.3 Network Service Between Regions

Directlink provides a network service between regions by facilitating the transfer of active power between the NEM regions of Queensland and NSW. Directlink has the capability to transfer power from Queensland to NSW and vice versa subject to local network constraints and Directlink's rating. This capability can be achieved independently of the scheduled generation in each state provided surplus generation capacity or parallel AC interconnectors are available. This provides an operationally flexible service to the system, unlike any AC interconnector service. Directlink can be used to supply shortfalls of generation in one region by transferring active power from the state with surplus generation. It may also be used to reduce network overloads or control the voltages in one state by transferring active power from one region to another or generating or absorbing reactive power.

[3] BRW has not recommended that the benefits associated with system stability be submitted for inclusion in the Regulatory Test. A discussion of the enhancement of interconnected system stability and security is not provided in the main body of this report but included for information in Appendix A

The inter-regional services that Directlink is able to provide can be leveraged by the TNSPs in place of alternative network augmentations to meet the requirements of the Code.

S5.1.3 Frequency Variations

Directlink can operate successfully over the extreme range of frequency excursions which are possible on the interconnected system.

S5.1.4 Magnitude of Power Frequency Voltage

Directlink has the capability to exert active control of the power frequency voltages. In this regard it assists the power system in which it is embedded. However, Directlink is significantly better than a conventional AC interconnector in this regard because it can exert this control for a much greater range of system conditions than is the case with a conventional AC interconnector. This is a service that could be utilised to satisfy the requirements of this part of the Code.

S5.1.5 Voltage Fluctuations

As described above in respect to S5.1.4, Directlink will reduce the voltage fluctuations which would otherwise occur in the power system in which it is embedded. As a result, it is able to defer the addition of other forms of reactive control which would otherwise be needed to limit voltage fluctuations to levels which comply with Code requirements.

S5.1.6 Voltage Harmonic Distortion

Directlink uses fast switching voltage sourced converter technology with appropriately designed filters. As a consequence, it contributes little harmonic distortion and operates well within relevant Australian standards.

S5.1.7 Voltage Unbalance

Directlink converters are controlled to ensure that they do not contribute to voltage unbalance. It is possible with appropriate modifications to operate the converters so that they act to partially offset any imbalance caused by reasons external to Directlink (eg. a system fault). This could defer the need to augment the network and assist with Code compliance.

S5.1.8 Stability

Voltage stability is required to have a reserve margin. A reserve margin of 1 % of the short-circuit level is used. This equates to approximately 50 MVAr of reactive margin for the Gold Coast area. This service could be utilised to assist with Code compliance and defer augmentations necessary to achieve stability.

S5.1.9 Protection Systems and Fault Clearance Times

Protection systems are included in the converter control system design which act to shut down the link (or part thereof as Directlink is in reality three independent links) if a serious control or electrical fault occurs.

Fault clearance times are not an appropriate concept for Directlink in the same manner as the term applies to generators. In the event of an electrical fault close enough to Directlink to cause loss of a voltage reference signal, Directlink will shut down. After fault clearance (independent of the time of fault), the voltage reference signal will be re-established and Directlink may re-commence operation.

S5.1.11 Automatic Reclosure of Transmission Lines

Automatic reclosure is the means whereby supply is automatically restored following a fault on an overhead line. On overhead lines, there is a high probability of the insulation self restoring upon clearance of the fault. In the case of Directlink, the interconnector is constructed using underground cables for its entire length. The insulation in underground cables is generally not self restoring following a cable fault and for this reason, automatic reclosure is not implemented.

2.3 Directlink's Rating

Directlink is an HVDC link based on ABB's HVDC Light® technology. This technology is available in modules and this particular installation comprises three parallel 60 MW modules, giving a maximum nominal active power flow capacity of 180 MW in either direction. BRW notes that the As-Tested Rating[4] of Directlink as advised by the Directlink owners is 58.3 MW per module at the receiving end.

For the purposes of this report the As-Tested Rating has been used in all of BRW's analysis and modelling work. Losses in the converter stations at each end of Directlink at Bungalora 110 kV and Mullumbimby 132 kV, and losses in the DC cable itself results in a significant difference between sending end power and receiving end power as shown in Table 2.3(a). The differential in the sending and receiving end power has been modelled in BRW's analysis.

[4] Directlink's rating capability was tested in June 2001.

Table 2.3(a) – Directlink Active Power Ratings at Nominal Voltage[5]

	Sending End	Receiving End
Nominal Rating	180 MW (3 x 60.0 MW)	168 MW (3 x 56.0 MW)
As-Tested Rating	188 MW (3 x 62.5 MW)	175 MW (3 x 58.3 MW)

The acceptable operating voltage range when operating at the As-Tested Rating is as follows in Table 2.3(b):

Table 2.3(b) – Directlink Acceptable Voltage Range at As-Tested Rating

Directlink Flow	**Bungalora (QLD 110 kV side)**	**Mullumbimby (NSW 132 kV side)**
QLD to NSW	Above 104.55 %	Below 104.45 %
NSW to QLD	Below 104.45 %	Above 99.00 %

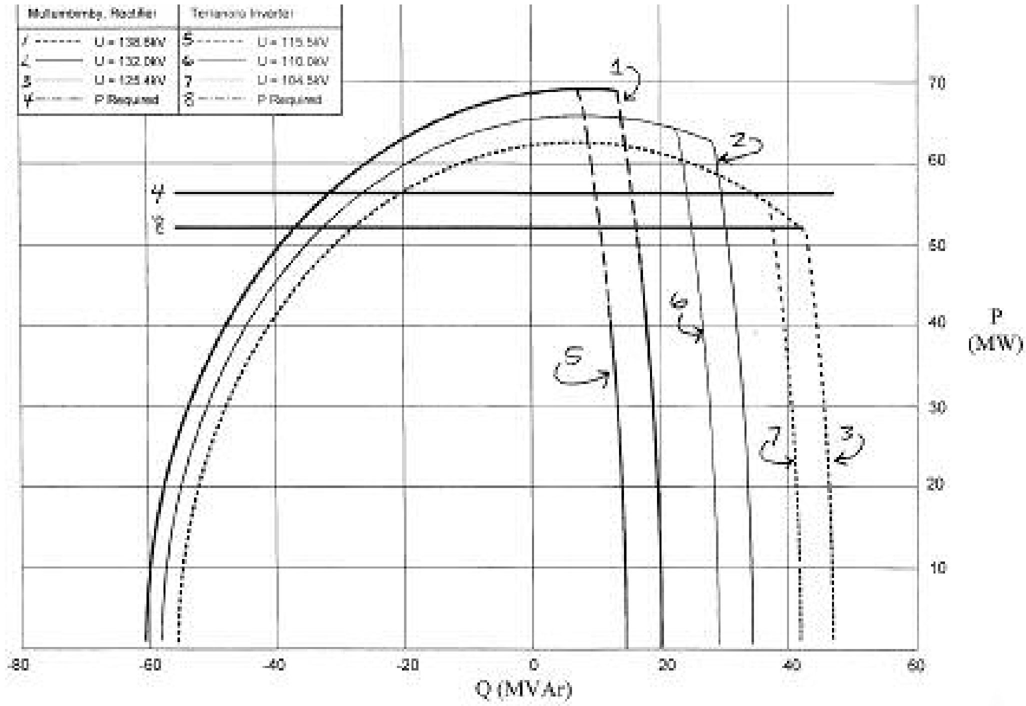
Directlink is also able to source or sink reactive power into the interconnected system as shown in Table 2.3(c).

Table 2.3(c) – Directlink Reactive Power Ratings at Nominal Voltage

	Maximum Leading	Maximum Lagging
No Load	-174 MVAr (3 x -58 MVAr)	90 MVAr (3 x 30 MVAr)
Rated Power	-75 MVAr (3 x -25 MVAr)	75 MVAr (3 x 25 MVAr)

The table above indicates that increasing the reactive power output requires a reduction in the sent-out active power capability, to remain within the rating of Directlink. The interdependency between the active and reactive power outputs over the entire operating range is accurately represented in the PQ characteristics such as that shown below:

[5] Source : Directlink Joint Venture



The active and reactive power transfers across Directlink are each controlled independently by the Directlink control systems. The HVDC Light® technology (unlike conventional HVDC) also allows the reactive power outputs at each end of the link to be controlled independently. Therefore Directlink acts to source or sink reactive power rather than to transfer reactive power.

2.4 Active Power Flow Capability

The flexibility of the HVDC Light® technology to control active power flow in any direction, independent of the generation scheduling, allows Directlink to provide a number of active power support services to the interconnected system including loss minimisation, optimisation of network utilisation for reliability gains, wholesale market support, with potential for post-contingent support, frequency control and black start capability.

Directlink's rating is only one aspect that determines the limit of Directlink's active power flow capability. The capability of Directlink can also be limited at times by network constraints in the vicinity of Directlink in both Queensland and NSW. Historical information presented by NEMMCO[6] indicates that transfer of power from Queensland to NSW is often constrained because of stability and thermal limits. As a regulated asset, Directlink could be dispatched to relieve some of these constraints, which would allow lower cost power to flow between the states. The cost saving to the market is proportional to the cost difference in power between NSW and Queensland. Relieving this constraint would cause the pool prices for the whole of the NEM to track each other more closely. These benefits are quantified in the report prepared by TransÉnergie US Ltd, which also accompanies the Directlink conversion application.

[6] Interconnector Quarterly Performance March – May 2003

Directlink provides a controlled, two-way injection capability into the Northern NSW Coastal and Queensland Gold Coast regions, subject to Directlink's rating and external network constraints defined by NEMMCO and the TNSP constraint equations and the connection agreements. The constraints on Directlink's full capability are presently voltage and thermal network constraints in both the NSW network around Lismore and the Queensland network around Mudgeeraba. In comparison, QNI constraints are predominantly stability related for imports to NSW and thermal related for imports to Queensland.

Directlink presently has a simple emergency control and tripping system implemented at remote substations to trip off Directlink in the advent of a critical network element outage. This means that Directlink is not able to actively support the network after the critical outage, particularly during periods of high demand in the Northern NSW and Gold Coast regions. A Directlink with post-contingent support implemented in its control systems that actively responds to the critical outage without tripping off would allow Directlink to be used to its full capability. The present constraints on Directlink (also impacting QNI) identified by BRW include:

For flows from NSW to Queensland, the Directlink constraints arise from:

- Voltage stability limit around Lower North Coast area of NSW
- Armidale–Lismore 132 kV thermal limits
- Tamworth-Armidale 330 kV thermal limit
- Liddell-(Muswellbrook)-Tamworth 330 kV thermal limits
- Lismore-Mullumbimby 132 kV thermal limit
- Lismore – Lismore 132 kV thermal limit
- Directlink's active power flow capability.

For flows from Queensland to NSW, the Directlink constraints arise from:

- Voltage stability limit in the Gold Coast area of Queensland (revised since the installation of Molendinar 275 kV)
- Mudgeeraba – Terranora 110 kV thermal limit
- Swanbank – Mudgeeraba / Molendinar 275 kV thermal limit
- Directlink's active power capability.

Constraint equations determining the value of the constraints are held by NEMMCO and are formulated by NEMMCO and the TNSPs. However, BRW has independently assessed the network constraints in the Gold Coast and North Eastern NSW regions by modelling and simulating the entire EHV networks between Tarong in Queensland and Liddell in NSW. This section of the network includes all of the Gold Coast and Far North

East NSW (and parts of the Lower North NSW Coast – specifically the area around Coffs Harbour) including Directlink and QNI.

2.5 Reactive Power Flow Capability and Voltage Control

One of the features which sets the ABB Light® technology ahead of other technologies is the ability to generate or absorb reactive power independently of, and concurrently with, active power flow control, within overall thermal and voltage limits.

This facility can be used to control the voltage of the AC network independently at both the sending and receiving ends of the link during normal network operations or following a network contingency. This form of voltage control is continuous, rather than occurring in discrete steps. For this reason it is a superior type of control to the switched capacitors or reactors which have been used over many decades. Its capacity to provide on-line, continuous regulation of the network voltage is similar to the control provided by a synchronous condenser or SVC. Even with the DC link cables out of service, the voltage control can still be provided at each end of the link.

The capability of Directlink's reactive support is limited by the following:

- 110 kV Bus voltage at Terranora – voltage outside acceptable limits
- 132 kV Bus voltage at Mullumbimby - voltage outside acceptable limits
- Lismore-Mullumbimby 132 kV thermal limit
- Mudgeeraba – Terranora 110 kV thermal limit
- Directlink's reactive power capability.

2.6 Network Support Capability

Directlink operates in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the NSW and Queensland NEM regions. This parallel operation means that there is some interdependency between the two interconnectors in the constraint equations. Despite this, QNI and Directlink connect into quite different parts of the transmission network. Directlink is a DC link connecting the load centres of far north eastern NSW with that of the Queensland Gold Coast at the 132 kV/110 kV level, whilst QNI is an AC link connecting the 330 kV NSW system with the 275 kV Queensland system. For these reasons, Directlink could provide its own unique network support services to the local networks, particularly if Directlink is augmented with post-contingent support control systems. These services would flow on to potential network augmentation deferments in both states for planned augmentations to the Gold Coast or far north east NSW.

2.7 Facilitation of Inter-regional Flows

Directlink enables real power transfer between the New South Wales and Queensland NEM regions to the level described above. This aspect of Directlink's network service enables better utilisation of available generation capacity throughout the NEM that creates important economic benefits in terms of lower generation costs, the deferment of new generation, reduction in the use of interruptible load, and reductions in the level of expected unserved energy.

2.8 Enhancement of Interconnected System Stability and Security

Whilst Directlink could have a beneficial impact on interconnected system stability and security, BRW has not recommended that the associated benefits be submitted for inclusion in the Regulatory Test as these benefits cannot be clearly defined at this stage. For this reason, the discussion of the enhancement of interconnected system stability and security is not provided in the main body of this report but included for information in Appendix A.

2.9 Network Augmentation Deferral Capability

The ability of Directlink to provide a network service particularly if augmented with post-contingent support, can result in deferment of planned reliability and system stability augmentations.

At present, there are a number of planned reliability augmentations proposed by the NSPs for NSW and Queensland in the 10 year planning period. BRW has identified a *second tranche* of reliability augmentations next decade, beyond the 10 year planning period, which have also been assessed. Further augmentations post 2020, have not been considered.

At present BRW has not found reference to any system stability augmentations planned for NSW and Queensland over the planning horizon.

In its present state, Directlink is not able to actively respond to critical network contingencies. Therefore its ability to provide network support to defer major reliability augmentations is limited. To provide more substantial network deferrals, BRW has assessed that implementation of post-contingent support in the Directlink control systems would be needed to allow Directlink to actively respond to critical contingencies, providing dynamic support to the network in both Queensland and NSW. The owners of Directlink have advised that the control system upgrade could be implemented in sufficient time before the planned network augmentations in 2005/6. BRW has assessed that Directlink with post-contingent support and additional reactive plant in the Gold Coast could defer major planned augmentations by a number of years.

3 DISCUSSION OF THE ALTERNATIVE PROJECTS

3.1 Basis for the Selection of Alternative Projects

The criteria that the ACCC set down in its Murraylink decision for the selection of alternative projects are as follows.[7]

> … the Commission believes that alternative projects should contain a level of similarity to the Murraylink, although they need not be technically identical. That is, an alternative project could be considered a reasonable alternative if it delivers substantial gross market benefits to all regions and or nodes.

In defining appropriate alternative projects for the application of the Regulatory Test, BRW has interpreted the ACCC's criteria and used the following measures in its selection process.

The alternative projects:

- are to be relevantly substitutable for Directlink but not necessarily equivalent;
- include all components necessary for them to be technically feasible;
- should attempt to address in part some of the existing and emerging local network constraints that Powerlink Queensland and TransGrid have recently identified[8];
- should make use of existing infrastructure and/or commercially available current technology;
- are to have real power transfer capabilities consistent with the limitations of the surrounding network infrastructure and not necessarily the same as Directlink - BRW chose the amount of real power transfer capability needed to provide the level of network support required in the Gold Coast and far north-eastern NSW;
- can provide reactive power transfer or generation capability - BRW chose the amount of reactive power capability necessary to make each alternative technically feasible. Where appropriate BRW has added the cost of additional reactive plant into the alternatives to the extent to make each alternative technically feasible. It is assumed that the TNSPs have their own reactive plant capital programs to address reactive demand growth and are not included as part of the alternative projects;
- shall use control schemes to an extent where the benefits exceed the cost of the control scheme and are technically acceptable - BRW has considered control schemes that provide post-contingent support are technically acceptable and justified. Therefore their costs and benefits have been defined for inclusion into

[7] ACCC, "Decision: Murraylink Transmission Company Application for Conversion and Maximum Allowable Revenue", 1 October 2003, pp. xiv, 52.

[8] As documented in Powerlink Queensland, "Emerging Transmission Network Limitations – Electricity Transfer to the Gold Coast and Tweed Area", August 2003 and TransGrid, "Emerging Transmission Network Limitations on the NSW Far North Coast", August 2003

the Regulatory Test. Control systems for system restart or system stability enhancement are not recommended for inclusion in the Regulatory Test;

- shall appropriately address environmental issues only to an extent that would be necessary for the alternative projects to gain environment and planning approval. BRW adopted the recommendation of URS Australia whose report on the environmental issues in the Tweed Heads and Byron Bay areas accompanies the Directlink conversion application.

3.2 Alternative 0 – Modified Directlink

3.2.1 Description of Alternative 0

Alternative 0 is the Directlink project with the addition of post-contingency network support capability and Gold Coast reactive support.

Alternative 0 consists of:

- first generation HVDC Light® technology as used for Directlink with a nominal 3x60 MW capacity to provide active and reactive power support to the Queensland Gold Coast and far north eastern NSW networks to relieve local thermal and voltage constraints, and to provide a controlled two-way interconnection between the Queensland and NSW regions. BRW notes that the actual cost of Directlink is well below the present market value of the technology and that the cost of replacing Directlink today would be substantially more. Alternative 0 includes the actual cost of Directlink rather than the current market value of the HVDC Light® technology as represented in Alternative 1.
- sites at Bungalora[9] and Mullumbimby for the converter stations.
- 150 MVAr of switched shunt capacitors distributed around the 110 kV Gold Coast network to raise the power factor at the 110 kV bulk supply points from approximately 0.92 to 0.97 and the 275 kV network supplying the Gold Coast to unity power factor estimated at around $A4.0M.
- protection and control systems to Code standards including emergency response capabilities to enable the provision of post-contingent support. Post-contingent support capability requires major control upgrades to the Directlink control equipment and the associated communications equipment estimated at around $A4.5M.
- underground cable for the entire length of the route using the existing Directlink route. Overhead line is not permitted to be used with HVDC Light® technology because of the susceptibility of the HV transistor equipment at the converter stations to lightning[10].

[9] Country Energy's Independent Planning Review into the Proposed Upgrade of the Terranora Electricity Substation has identified objections from the Terranora Residents Committee regarding further expansions to Terranora substation. Establishment of a converter station or transformer at the existing Terranora site would require a substantial increase in the size of the substation site to physically fit the plant and would substantially impact the local community. To address this issue, Bungalora is selected as a viable alternative site for the plant in the alternative projects.

[10] Mike Wyckmans of ABB confirmed to BRW on 11/3/04 that the HVDC Light® link must be completely underground.

3.2.2 Definition of Network Service Provided by Alternative 0

3.2.2.1 Active Power Flow Capability

Alternative 0 implements the HVDC Light® technology. Its ability to control active power flow in any direction, independent of the generation scheduling, allows Alternative 0 to provide a number of active power support services to the interconnected system including loss minimisation, optimisation of network utilisation for reliability gains, wholesale market support and post-contingent support.

Alternative 0 provides a controlled, two-way nominal 180 MW injection capability into the Northern NSW Coastal and Queensland Gold Coast regions and implements post-contingent support to respond to critical network contingencies and provide network support.

3.2.2.2 Reactive Power Flow Capability and Voltage Control

One of the features which set the modern transistor technology ahead of other DC technologies is the ability to generate or absorb reactive power flows independently of, and concurrently with, active power flow control, within overall thermal and voltage limits.

This facility can be used to control the voltage of the AC network at both the sending and receiving ends of the link during normal network operations or following a network contingency.

This voltage control is continuous, rather than occurring in discrete steps. For this reason it is a superior type of control to the switched capacitors or reactors which have been used over many decades. Its capacity to provide on-line, continuous regulation of the network voltage is similar to the control provided by a synchronous condenser or SVC.

3.2.2.3 Network Support Capability

Alternative 0 operates in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the NSW and Queensland NEM regions. This parallel operation means that there is some interdependency between the two interconnectors. Despite this, QNI and Alternative 0 connect into quite different parts of the transmission network. Alternative 0 is a DC link connecting the load centres of far north eastern NSW with that of the Queensland Gold Coast at the 132 kV/110 kV level, whilst QNI is an AC link connecting the 330 kV NSW system with the 275 kV Queensland system. Being implemented with post-contingent support, Alternative 0 could provide its own unique network support services to the local networks. These services would flow on to potential network augmentation deferments in both states for planned augmentations to the Gold Coast or far north east NSW.

3.2.2.4 Facilitation of Inter-regional Flows

Alternative 0 enables real power transfer between the New South Wales and Queensland regions to the level described above. This aspect of the Alternative 0 network service enables better utilisation of available generation capacity throughout the NEM that creates important economic benefits in terms of lower generation costs, the deferment of new generation, reduction in the use of interruptible load, and reductions in the level of expected unserved energy.

3.2.2.5 Deferment of Capital Investment

With the implementation of post-contingent support capability and installation of reactive plant on the Gold Coast, Alternative 0 can defer substantial network investments in both Queensland and NSW. The deferral periods are detailed in Section 4 for the entire planning horizon up to 2020.

3.2.3 Reasonable Alternative

BRW recommends that Alternative 0 be assessed as a reasonable alternative project for the purpose of applying the Regulatory Test.

3.3 Alternative 1 – Modern HVDC Light®

3.3.1 Description of Alternative 1

Alternative 1 consists of:

- modern HVDC Light® link (or equivalent) with a nominal 180 MW capacity (to match approximately the capability of the surrounding network) to provide active and reactive power support to the Queensland Gold Coast and far north eastern NSW networks to relieve local thermal and voltage constraints and to provide a controlled two-way interconnection between the Queensland and NSW regions. Second generation converter design (developed since the installation of Directlink) would be employed rather than the first generation design that was used for Directlink. At the time that Directlink was built, HVDC Light® technology was in its infancy, which necessitated the building of three converters rated at 60 MW each. If a similar project were implemented today, then second generation converter design could be exploited which would only require the use of one link rather than three links in parallel. BRW had expected that the cost of establishing a single link would be lower than three in parallel, however it is noted by BRW that the actual as-paid cost of Directlink is well below the present market value of the technology (even with inflation taken into account) and that the cost of replacing Directlink today would be substantially more. BRW has used the 2004 market value of the HVDC Light® technology in its assessment of the cost of Alternative 1. The as-paid cost of Directlink is included as Alternative 0.
- sites established at Bungalora and Mullumbimby for the converter stations.
- 150 MVAr of switched shunt capacitors distributed around the 110 kV Gold Coast network to raise the power factor at the 110 kV bulk supply points from approximately 0.92 to 0.97 and the 275 kV network supplying the Gold Coast to unity power factor.
- protection and control systems to NEC standards including dynamic active and reactive power support and emergency response capabilities including post-contingent support.
- underground cable for the entire length of the route. Overhead line cannot be used with HVDC Light® technology because of the susceptibility of the HV transistor equipment at the converter stations to lightning.

3.3.2 Definition of Network Service Provided by Alternative 1

3.3.2.1 Active Power Flow Capability

Alternative 1 implements the HVDC Light® (or equivalent) technology. Its ability to control active power flow in any direction, independent of the generation scheduling, allows Alternative 1 to provide a number of active power support services to the interconnected system including loss minimisation, optimisation of network utilisation for reliability gains, wholesale market support and post-contingent support capability.

Alternative 1 provides a controlled, two-way nominal 180 MW injection capability into the Northern NSW Coastal and Queensland Gold Coast regions and implements post-contingent support to relax the constraints that are presently imposed on Directlink.

3.3.2.2 Reactive Power Flow Capability and Voltage Control

One of the features that set the modern transistor technology of HVDC Light® ahead of other DC technologies is its capability to control and generate reactive power flows independently of, and concurrently with, active power flow control, within overall thermal and voltage limits.

This capability can be used to control the voltage of the AC network at both the sending and receiving ends of the link during normal network operations or following a network contingency.

This voltage control is continuous, rather than occurring in discrete steps. For this reason it is a superior type of control to the switched capacitors or reactors that have been used over many decades. Its capacity to provide on-line, continuous regulation of the network voltage is similar to the control provided by a synchronous condenser or SVC.

3.3.2.3 Network Support Capability

Alternative 1 operates in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the NSW and Queensland NEM regions. This parallel operation means that there is some interdependency between the two interconnectors. Despite this, QNI and Alternative 1 connect into quite different parts of the transmission network. Alternative 1 is a DC link connecting the load centres of far north eastern NSW with that of the Queensland Gold Coast at the 132 kV/110 kV level, whilst QNI is an AC link connecting the 330 kV NSW system with the 275 kV Queensland system. Being implemented with post-contingent support, Alternative 1 could provide its own unique network support services to the local networks. These services would flow on to potential network augmentation deferments in both states for planned augmentations to the Gold Coast or far north east NSW.

3.3.2.4 Facilitation of Inter-regional Flows

Alternative 1 enables real power transfer between the New South Wales and Queensland regions to the level described above. This aspect of the Alternative 1 network service enables better utilisation of available generation capacity throughout the NEM that creates important economic benefits in terms of lower generation costs, the deferment of new generation, reduction in the use of interruptible load, and reductions in the level of expected unserved energy.

3.3.2.5 Deferment of Capital Investment

With the implementation of post-contingent support capability and installation of reactive plant on the Gold Coast, Alternative 1 can defer substantial network investments in both Queensland and NSW. The deferral periods are detailed in Section 4 for the entire planning horizon up to 2020.

3.3.3 Reasonable Alternative

BRW concludes that Alternative 1 is a reasonable alternative for the purpose of applying the Regulatory Test.

3.4 Alternative 2 – Conventional HVDC

3.4.1 Description of Alternative 2

Alternative 2 consists of:

- conventional HVDC link with a 180 MW power transfer capacity to provide active power support to the Queensland Gold Coast and far north eastern NSW networks to relieve local thermal constraints and to provide a controlled two-way interconnection between the Queensland and NSW regions. This capacity is appropriately sized to be compatible with the capacity of the surrounding network.
- synchronous condenser and switched shunt capacitor installations (incorporated with the converter station filtering) on each side of the HVDC link to provide reactive power support to the Gold Coast and far north eastern NSW networks to relieve local voltage constraints. BRW has assessed that one of the present constraints in the region is voltage deviations. Installation of a conventional HVDC station without the provision of additional reactive support would be detrimental to the network and provide a lower quality service. BRW also recommends the additional reactive support (specified below) be provided with this alternative.
- sites established at Bungalora and Mullumbimby for the converter stations.
- 150 MVAr of switched shunt capacitors distributed around the 110 kV Gold Coast network to raise the power factor at the 110 kV bulk supply points from approximately 0.92 to 0.97 and the 275 kV network supplying the Gold Coast to unity power factor.
- protection and control systems to NEC standards including dynamic active and reactive power support and emergency response capabilities including post-contingent support.
- overhead line for part of the route length with the remainder undergrounded through sensitive environmental areas. The circuit route followed by Alternative 2 includes a relatively heavily populated corridor of Northern NSW. This area is well known as a popular holiday and retirement destination, and includes many areas of natural beauty. In the opinion of BRW and URS, it is not environmentally nor technically feasible to construct a line as an overhead pole mounted design for the entire route length and therefore some tactical placement of underground cable has been included with this alternative project (for further details refer to Section 5 of this report, and the accompanying URS report).

The difference between conventional HVDC and HVDC Light® is that conventional HVDC uses current commutated converters whereas HVDC Light® uses voltage source converters. The salient technical differences between the two types of technology are:

- Conventional HVDC requires generators or synchronous condensers at both ends of the link to raise fault levels and ensure current commutation. This limits its ability to operate in low fault level systems. HVDC Light® is not limited in this way.
- Conventional HVDC converters always absorb reactive power from the system at both terminals. This means that reactive support in the form of shunt capacitors (usually configured as harmonic filters) must be included in the design to at least offset the reactive load of the converters. HVDC Light® systems require minimal filtering and no additional reactive support.
- Conventional HVDC systems change their reactive power demands in accordance with their active power flow. HVDC Light® systems can control their reactive power output largely independent of the active power throughput.
- HVDC current commutated converters do not require the DC link to be implemented using underground cable because of the use of thyristor technology rather than HVDC Light® transistor technology. Underground cable has only been included to the extent that it would be required to gain environmental and planning approvals.

3.4.2 Definition of Services Provided by Alternative 2

3.4.2.1 Active Power Flow Capability

Alternative 2 implements the HVDC conventional technology. Its ability to control active power flow in any direction, independent of the generation scheduling, allows Alternative 2 to provide a number of active power support services to the interconnected system including loss minimisation, optimisation of network utilisation for reliability gains, wholesale market support and post-contingent support.

Alternative 2 provides a controlled, two-way nominal 180 MW injection capability into the Northern NSW Coastal and Queensland Gold Coast areas and implements post-contingent support to relax the constraints on the capability of Alternative 2.

3.4.2.2 Reactive Power Flow Capability and Voltage Control

In its basic design, Alternative 2 cannot be used to defer reactive plant expenditure. This alternative would cause the installation of reactive power plant to be brought forward because it is needed to offset the reactive power demands of the converter plant. For this reason additional reactive plant is included in the converter station filters to offset the reactive demands. The combination of the synchronous condensers and additional reactive capacity is used to support the Gold Coast and far North East NSW networks.

3.4.2.3 Network Support Capability

Alternative 2, like Directlink would operate in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the NSW and Queensland NEM regions. However, QNI and Alternative 2 connect into quite different parts of the transmission network. Alternative 2 is a DC link connecting the load centres of far north eastern NSW with that of the Queensland Gold Coast at the 132 kV/110 kV level, whilst QNI is an AC link connecting the 330 kV NSW system with the 275 kV Queensland system. Being implemented with post-contingent support, Alternative 2 could provide its own unique network support services to the local networks. These services would flow on to potential network augmentation deferments in both states for planned augmentations to the Gold Coast or far north east NSW.

3.4.2.4 Facilitation of Inter-regional Flows

Alternative 2 enables real power transfer between the New South Wales and Queensland regions to the level described above. This aspect of the Alternative 2 network service enables better utilisation of available generation capacity throughout the NEM that creates important economic benefits in terms of lower generation costs, the deferment of new generation, reduction in the use of interruptible load, and reductions in the level of expected unserved energy.

3.4.2.5 Deferment of Capital Investment

The reliability augmentation deferment capability of Alternative 2 is identical to Alternative 1 and Alternative 0 and better than Directlink as it is currently configured, because Alternative 2 would be designed to provide post-contingent support. Refer to Section 4 for the deferments possible during the entire planning horizon up to 2020.

3.4.3 Reasonable Alternative

BRW concludes that Alternative 2 is a reasonable alternative for the purpose of applying the Regulatory Test.

3.5 Alternative 3 – AC Link with Phase Shifting Transformer

3.5.1 Description of Alternative 3

At the time Directlink was established, it was the only transmission interconnection in existence between the NSW and Queensland regions. Being connected to the 132 kV and 110 kV parts of the system (rather than at the 330 kV and 275 kV level) and having a relatively small capacity with respect to the size of the Queensland and NSW systems, this and the Safe Harbour Provisions dictated that Directlink be established as a controllable DC link. Since the installation of Directlink, the QNI interconnection has been established between the two states in the form of a high capacity, double circuit, 330 kV AC link. Had Directlink been installed after QNI, it could have potentially been established as an AC link. As the Directlink owners are seeking regulated status post QNI commissioning, BRW has included AC options as part of its selection of alternative projects to supplement the DC alternative projects.

Alternative 3 consists of:

- 132 kV AC link including a 132 kV/110 kV phase shifting transformer comprising of three single phase units[11] with a ± 30 degree tapping range at the Queensland end. The capacity of the link would be 180 MW to provide active power support to the Queensland Gold Coast at Terranora and far north eastern NSW networks at Mullumbimby to relieve local thermal constraints and to provide a controlled, two-way interconnection between the Queensland and NSW regions. Provision has been made in Alternative 3 for a spare phase (i.e. four single phase units). Whilst a spare phase is not essential for the delivery of services by Alternative 3, BRW believes the uniqueness of such a phase shifting transformer in the Australian transmission network would require a spare to be purchased due to the long lead time for replacement (at least 12 months) with no ability to transfer another transformer to this site in the event of a failure. BRW notes that in the Murraylink case, the ACCC took issue with the provision of a spare (second) transformer. Notwithstanding this, BRW is of the view that a stronger case can be mounted for the provision of a spare phase for Directlink and considers that it would be imprudent to construct this alternative without a spare phase as the services specified could not be delivered without a phase shifting transformer. The cost of four single-phase units is lower than the cost of two three-phase units.
- site established at Bungalora for the transformer.
- 150 MVAr of switch shunted capacitors distributed around the 110 kV Gold Coast network to raise the power factor at the 110 kV bulk supply points from approximately 0.92 to 0.97 and the 275 kV transmission network supplying the Gold Coast to unity power factor. In addition to this, small switched shunt capacitor installations on each side of the AC link to provide local post-contingent

[11] Transportation issues dictate the use of single phase units.

voltage support for each side of the link[12]. BRW has assessed that one of the present constraints in the region is voltage stability. Installation of a transformer without the provision of additional reactive support would be detrimental to the network and provide a lower quality service.

- protection and control systems to NEC standards and post-contingent support capability to adjust the transformer phase angle to alleviate network constraints.
- overhead single circuit, 132 kV, AC pole line for part of the route length with the remainder undergrounded through sensitive environmental areas. The circuit route followed by Alternative 3 includes a relatively heavily populated corridor of Northern NSW. This area is well known as a popular holiday and retirement destination, and includes many areas of natural beauty. In the opinion of BRW and URS, it is neither environmentally nor technically feasible to construct a line as an overhead pole mounted design for much of the route, forcing the design to be partly underground cable.[13] The use of underground cable adds substantial cost onto Alternative 3, but its use has been kept to a minimum.
- modifications to the existing substations at each end, namely at Terranora and Mullumbimby would be required for cable connections. Upgrading of existing protection, control and communications systems would also be required.

3.5.2 Definition of Network Service Provided by Alternative 3

3.5.2.1 Active Power Flow Capability

The maximum active power flow for Alternative 3 is 180 MW, selected on the basis of being a compatible value for the capability of the surrounding network to which it is being connected. The actual maximum flow available at any particular time may be less that 180 MW and is strongly dependent on the power flows on QNI, with the marginal flows on Alternative 3 tending to follow QNI. The direction of the active power flow is selectable, though not to the same extent as Directlink or Alternatives 0, 1 and 2 because of this dependence on QNI. For example, if QNI is transferring bulk power from Queensland to NSW, then it is relatively easy to transfer 180 MW over the Alternative 3 link from Queensland to NSW within the available transformer tapping range. However, to transfer 180 MW in an opposing direction across the Alternative 3 link may not be possible in the available transformer tapping range.

This capability reduction will have only a minimal impact on interregional benefits because QNI and Alternative 3 flows would generally be dispatched in the same direction by the NEM. However flows in opposing directions may be required for network support and Alternative 3's limited capability to do this reduces its ability to defer the next tranche of network support augmentations for the Gold Coast and far north east of NSW.

[12] BRW has used switched shunt capacitors in this alternative project because an SVC cannot be economically justified for the stipulated deferment period of this alternative.

[13] Refer to Section 5 and accompanying URS report for route selection details.

Achieving total independence from QNI to release the full 180 MW capabilities would not be technically feasible as the phase angle requirement for the phase shifting transformer would be substantial. BRW has estimated that phase angles up to 75 degrees (compared to the nominated 30 degrees) would be needed to achieve this independence from QNI at QNI's present maximum capability. This would worsen if QNI's capability were increased beyond the present stability limits. BRW does not believe this range is practical and has therefore limited the tapping extent to 30 degrees. A 75 degree phase shift could introduce severe operational limitations and safety issues relating to switchgear capability, transmission line auto-reclosure problems and system stability issues.

Like the other alternative projects, Alternative 3 active power transfer capability can also be limited by the limitations of the surrounding networks.

Alternative 3 is able to provide support to QNI in the event that one of the QNI circuits should trip or be otherwise unavailable. Unlike the DC alternatives, this AC link alternative would need to be taken out of service if QNI is tripped out of service. QNI is a double circuit interconnection, therefore a double circuit outage is unlikely.

The speed of response for this alternative is relatively slow. That is, the transformer tap changing mechanism takes many seconds to change taps. This control measure is required to adjust the active power flow.

Some reduction in system losses is possible with this option in the Gold Coast and the far north eastern NSW networks by optimising the power flows between the two areas.

3.5.2.2 Reactive Power Flow Capability and Voltage Control

The inclusion of additional switched shunt capacitors on each side of the transformer for post-contingent support and switched capacitors in the Gold Coast for the provision of reactive power to support steady state voltages at each end of the link is a requirement for this alternative project.

The transient response is marginal due to the use of switched shunt capacitors to provide part of the reactive support rather than reliance on the fast control systems provided by either of the DC alternatives. An SVC included with this option would assist in replicating the performance of the DC alternatives, however BRW could not justify the additional cost of an SVC based on the marginal increase in deferment benefit an SVC could provide using a phase shifting transformer with a ± 30 degree tapping range.

3.5.2.3 Network Support Capability

Alternative 3, like Directlink would operate in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the NSW and Queensland NEM regions. However, QNI and Alternative 3 connect into quite different parts of the transmission network. Although Alternative 3 is an AC link, its ability to control power flows to a limited extent coupled with an implementation of post-contingent support, allows Alternative 3 to provide its own unique network support services to the local networks. These services would flow on to potential short term network augmentation deferments in both states for planned augmentations to the Gold Coast or far north east of NSW.

3.5.2.4 Facilitation of Inter-regional Flows

Alternative 3 enables real power transfer between the New South Wales and Queensland regions to the level described above. This aspect of the Alternative 3 network service enables better utilisation of available generation capacity throughout the NEM that creates important economic benefits in terms of lower generation costs, the deferment of new generation, reduction in the use of interruptible load, and reductions in the level of expected unserved energy.

3.5.2.5 Deferment of Capital Investment

This alternative project would be able to supply load in both the Queensland Gold Coast and the far north eastern NSW areas. BRW has assessed that this would permit the deferment of other capital investments by the utilities in these areas. Although the maximum capability of the link is 180 MW, it can be reduced substantially for certain QNI flows particularly for flows in the reverse direction of flows on QNI. For this reason the deferment benefit is substantially less than the DC alternative projects. Section 4 provides the level of deferment possible with Alternative 3 over the planning horizon up to 2020.

3.5.3 Reasonable Alternative

The ability of Alternative 3 to support the local network constraints and to transfer power between the Queensland and NSW regions is very much dependant on the flows on QNI. As such the market benefits of Alternative 3 would be substantially less than the DC alternative projects, and BRW considers that Alternative 3 would not be a suitable replacement for Directlink for the purposes of an ODRC[14] valuation.

Nevertheless, BRW concludes that Alternative 3 is a reasonable alternative for the purpose of applying the Regulatory Test.

[14] ODRC means optimised depreciated replacement cost.

3.6 Alternative 4 – AC Link with Conventional Transformer

3.6.1 Description of Alternative 4

Alternative 4 consists of:

- 250MVA rated AC link with a conventional 132 kV/110 kV auto transformer with three single phase units at the Queensland end to provide active power support to the 110 kV Gold Coast network at Terranora and the 132 kV far north eastern NSW network at Mullumbimby to provide an uncontrolled, two-way interconnection between the Queensland and NSW regions. This single circuit AC interconnection must be rated at 250 MVA if it is not to constrain the active power flows on QNI. Provision has been made in Alternative 4 for a spare phase (i.e. four single phase units). Whilst a spare phase is not essential for the delivery of services by Alternative 4, BRW believes the uniqueness of such a transformer in the Australian transmission network would require a spare to be purchased due to the long lead time for replacement (at least 9 months) with no ability to transfer another transformer to this site in the event of a failure.
- site established at Bungalora for the transformer.
- switched shunt capacitor installations on each side of the AC link to provide local voltage support on each side of the link. Installation of a transformer without the provision of additional reactive support would be detrimental to the network and provide a lower quality service[15].
- protection and control systems to NEC standards. Post-contingent support cannot be provided with this option and therefore the asset needs to be operated in pre-contingent mode. Emergency controls similar to that currently implemented on Directlink need to be included with this alternative to trip the link in the event of a critical contingency that results in network overloading.
- overhead line for part of the route length with the remainder undergrounded through sensitive environmental areas. The circuit route followed by Alternative 4 is the same as the routes for Alternatives 2 and 3 and includes, as mentioned previously for Alternatives 2 and 3, the relatively heavily populated corridor of Northern NSW. The use of underground cable adds substantial cost onto Alternative 4 but its use is kept to a minimum.
- modifications to the existing substations at each end, namely at Terranora and Mullumbimby will be required for cable connections with protection, control and communication modifications.

[15] BRW has used switched shunt capacitors in this alternative project because an SVC cannot be economically justified for the stipulated deferment period of this alternative.

3.6.2 Definition of Services Provided by Alternative 4

3.6.2.1 Active Power Flow Capability

The maximum active power flow is 250 MW selected on the basis of not restricting presently defined maximum flows on QNI. This is 70 MW more than the nominal rating of Alternative 3. The actual maximum power flow available at any particular time will generally be much less that 250 MW and is strongly dependent on the power flows on QNI. Power flows on this alternative link will follow the profile of QNI flows. BRW notes that although this alternative has a maximum transfer capacity nominally greater than Alternative 3, this additional capacity can only be utilised for maximum flows on QNI and even then may be limited by the capability of the surrounding 110 kV and 132 kV networks.

In a similar manner to Directlink, Alternative 4 is able to provide support to QNI in the event that one of the QNI circuits should trip or otherwise be unavailable.

The direction of the active power flow is not selectable, as is the case with Directlink or the DC alternatives (and to some extent Alternative 3). Rather the direction of the power flow will be dictated by the flows on QNI and the distribution of loads and system impedances in the Gold Coast and far north east NSW networks.

Minimisation of the local system losses as per Directlink in the Gold Coast and far north eastern NSW networks is not possible with this alternative project.

Unlike the DC alternatives, this AC link alternative would need to be taken out of service if both QNI circuits are tripped out of service.

BRW notes that the 250 MW capacity is larger than what the surrounding network can support under (N-1) conditions. Therefore an emergency tripping scheme shall be required to trip the link following a critical network contingency.

3.6.2.2 Reactive Power Flow Capability and Voltage Control

The inclusion of additional switched shunt capacitors on each side of the transformer for the provision of reactive power to support steady state voltages at each end of the link is a requirement for this alternative.

Transient response is inferior to Directlink due to the use of switched shunt capacitors to provide part of the reactive support.

3.6.2.3 Network Support Capability

Alternative 4, like Directlink would operate in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the NSW and Queensland NEM regions. However, QNI and Alternative 4 connect into quite different parts of the transmission network. Alternative 4 is an AC link, therefore its flows are closely related to flows on QNI. Alternative 4 has no ability to control power flows and has no ability to provide post-contingent support. For these reasons Alternative 4 provides essentially no local network support service to the local networks and under some QNI flow scenarios, violates the network constraints.

3.6.2.4 Facilitation of Inter-regional Flows

Alternative 4 enables real power transfer between the New South Wales and Queensland regions to the level described above. This aspect of the Alternative 4 network service on a regional basis enables better utilisation of available generation capacity throughout the NEM that creates important economic benefits in terms of lower generation costs, the deferment of new generation, reduction in the use of interruptible load, and reductions in the level of expected unserved energy.

3.6.2.5 Deferment of Capital Investment

This alternative is able to supply load in both the Queensland Gold Coast and the far north eastern NSW areas. However the amount of capital deferment is only available to the extent that QNI flows can be modified following a network contingency. For this reason, this alternative is not able to provide capital deferment benefit for every QNI flow scenario. Section 4 provides the level of deferment possible with this alternative project over the planning horizon to 2020.

The ability of Alternative 4 to support the local network constraints is extremely limited with the flows almost totally dependant on the flows on QNI. Under some QNI flow scenarios, network support is possible. However when all possible QNI import/export scenarios were evaluated, Alternative 4 was found to fail to provide network support in at least one scenario. As such, no network augmentation deferral benefits are possible for Alternative 4. For this reason, BRW has not included additional reactive support for the Gold Coast in the scope of this alternative project.

3.6.3 Not a Reasonable Alternative

Alternative 4 is representative of a typical AC interconnection option. However, the performance of Alternative 4 is lower in every aspect compared with the previous alternative projects and brings no network augmentation deferment benefits. Given that Alternative 4 is unable to provide adequate levels of network support, it is BRW's opinion that this project would not be a suitable replacement for Directlink for the purposes of an ODRC valuation, nor would it be a reasonable alternative for purposes of applying the Regulatory Test and has not been considered in any detail further in this report.

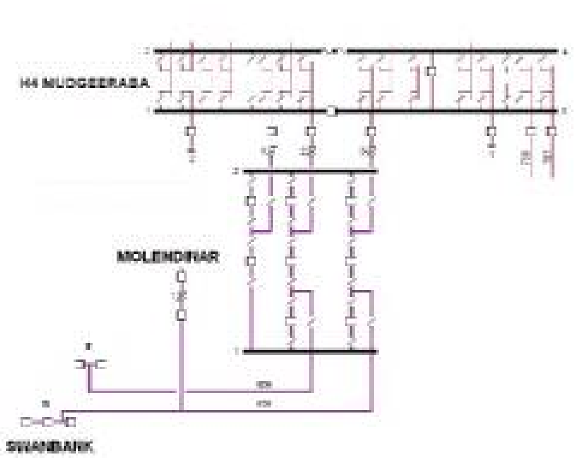
3.7 Alternative 5 – State Based AC Augmentations

3.7.1 Description of Alternative 5

Alternative 5 consists of augmentations similar to that which Powerlink and TransGrid have proposed to alleviate the network constraints that will emerge in the Gold Coast and far north coast of NSW areas in 2005 and 2006. BRW has confirmed that these projects would be required to support the respective transmission networks in the absence of Directlink providing network support. The projects may differ slightly in scope from the TNSPs proposals due to limited access BRW had to detailed TNSP scope of works, but it is expected these projects will deliver similar outcomes. BRW has identified that these projects and therefore the TNSP proposed projects, could potentially be deferred by the other alternative projects except for Alternative 4.

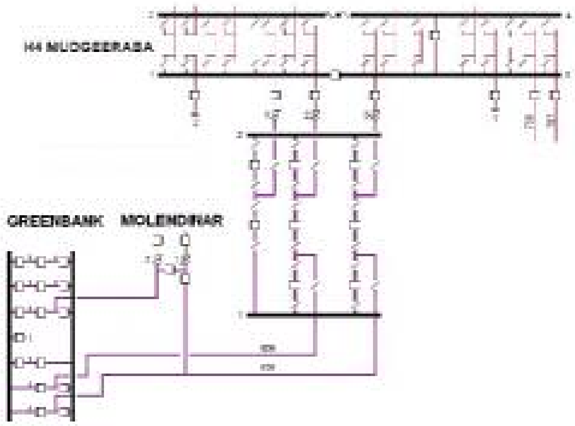
The Queensland investments for Alternative 5 consist of a new 275 kV AC line in Queensland linking a new Greenbank substation with Molendinar substation. The new line would be constructed between Greenbank and Maudsland with an existing circuit between Maudsland and Molendinar forming the remaining part of the line. The new 275kV substation would include switchgear to cut into existing 275kV lines through the site and a new 120 MVAr capacitor bank. A new 275 kV/110 kV transformer would be installed at Molendinar substation at about the same time to cater for load growth. This reliability augmentation is needed to provide active and reactive power support to the Gold Coast network to relieve the present local thermal and voltage constraints. The augmentation is required to provide continuity of supply to the Gold Coast loads ex Mudgeeraba and Molendinar following the most critical outage, namely the loss of the existing Swanbank to Mudgeeraba/Molendinar 275 kV teed line (Line 806). The Queensland augmentation has been costed on the basis that it would be a single circuit overhead transmission line using steel lattice towers with potential to be upgraded to double-circuit in the future. The teed line remains to form the second circuit into Molendinar.

Prior to QLD Alternative 5 Augmentation

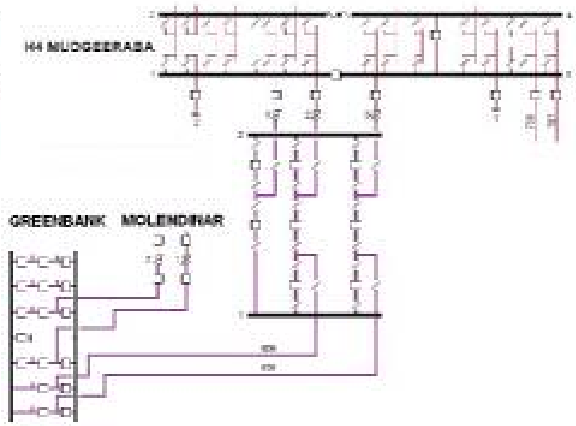


Following the QLD Alternative 5 Augmentation

i) Project Proposed by BRW

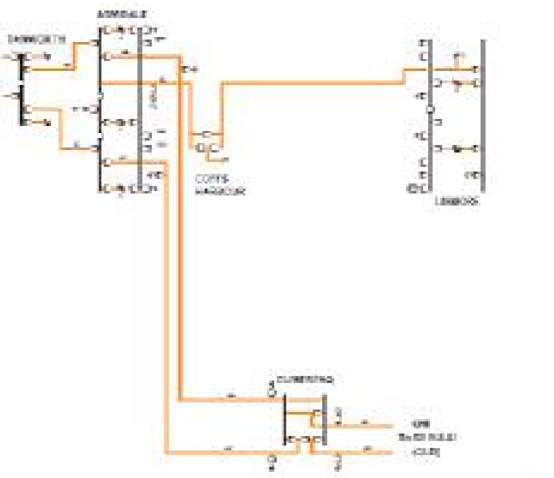


ii) Alternative Arrangement with 2nd Greenbank line

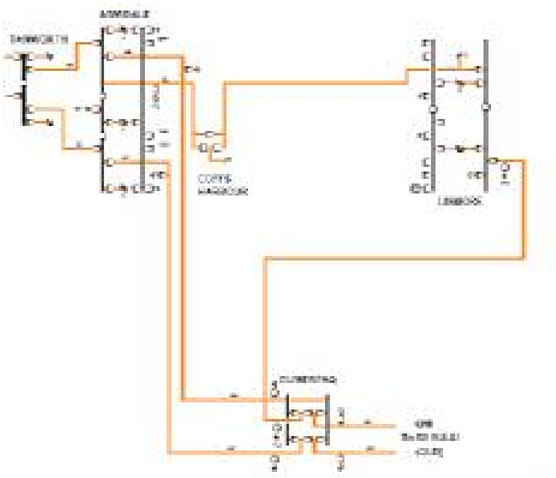


The NSW investment for Alternative 5 consists of a new 330 kV AC line in NSW linking Dumaresq substation with Lismore substation to provide active and reactive power support to the far north eastern NSW network to relieve present local thermal and voltage constraints. The new line is required to provide continuity of supply to Lismore following the most critical outage, namely the loss of the existing Armidale to Lismore 330 kV line (Line 89). The NSW augmentation has been costed on the basis that it would be a single circuit overhead transmission line using steel lattice towers. The line would follow the route of the existing 132 kV line from Lismore to Tenterfield and then continue to Dumaresq. Substation modifications and additional switchgear is required at Dumaresq and Lismore to connect the new line.

Prior to NSW Alternative 5 Augmentation



Following the NSW Alternative 5 Augmentation



For the avoidance of doubt, apart from QNI, Alternative 5 does not include an interconnector between the Queensland and New South Wales regions

BRW has assumed that the transmission lines for Alternative 5 would be constructed as overhead AC lines. In practice, total overhead construction may not be acceptable to relevant environmental and planning approval bodies. In the event that significant undergrounding would be required, there would be a significant increase the cost of Alternative 5, and, as a result, an increase the deferral benefits for Alternatives 0, 1, 2 and 3. Therefore, the deferral benefits BRW has calculated for Alternatives 0, 1, 2 and 3 are conservative.

Major upgrading of existing protection, control and communications systems would be required in both the NSW and Queensland regions for the implementation of Alternative 5. These costs have been included in the project cost.

3.7.2 Definition of Services Provided by Alternative 5

3.7.2.1 Active Power Flow Capability

As Alternative 5 contains no interconnection between the Queensland and New South Wales regions except the existing QNI, no additional active power transfer between the regions would be made possible by Alternative 5.

System losses will be reduced by the construction and use of Alternative 5.

Alternative 5 does not provide increased thermal power transfer capability between the Queensland and NSW regions on QNI.

3.7.2.2 Reactive Power Flow Capability and Voltage Control

The number of static capacitors required in this alternative for steady state voltage control at load centres for equivalence with Directlink is substantially reduced in each of the two states. This is due to the line charging and lower reactive losses from each of the new transmission assets.

3.7.2.3 Network Support Capability

Alternative 5, unlike Directlink does not provide local network support from one region to the other. Instead the local support is provided with an augmented connection between the local network and the state’s generation supplies. For this reason, augmentations are required in both states to address the local network constraints in each state individually.

3.7.2.4 Facilitation of Inter-regional Flows

The augmentation projects provide no facilitation of inter-regional flows. These are related to reliability augmentations to address local network constraints in the Gold Coast and far north eastern NSW.

3.7.2.5 Deferment of Capital Investment

Alternative 5 is an alternative which is similar to the projects proposed by the Queensland and NSW transmission system planning authorities in their capital planning for commissioning around 2005-6.

Alternative 5 may be deferred by Directlink or the other alternative projects to varying extents. On this basis, Alternative 5 is used in the set of projects that Directlink or the other alternative projects may defer when calculating the deferral benefit streams.

BRW notes that Alternative 5 is based on a totally overhead construction. In the event that undergrounding is required, significant increases in the project cost could occur and as a result, increase the deferral benefits for Directlink and the alternative projects. The deferral benefits calculated for overhead construction are therefore likely to be conservatively low.

3.7.3 Reasonable Alternative

Alternative 5 provides no increase in interconnection capability between Queensland and NSW. Alternative 5 will address present transmission network constraints in the far north eastern area of NSW and the Gold Coast.

BRW concludes that Alternative 5 is a reasonable alternative for the purpose of applying the Regulatory Test.

3.8 Alternative 6 – Embedded Generation / Demand Management

3.8.1 Description of Alternative 6

Alternative 6 consists of:

- New embedded generation in both the far north eastern NSW and Gold Coast networks to provide active and reactive power support to these networks to relieve local thermal and voltage constraints, and/or,
- Demand management in both the far north eastern NSW and Gold Coast networks to provide load relief to these networks to relieve local thermal and voltage constraints.

For the avoidance of doubt, Alternative 6 does not include an interconnector between the Queensland and New South Wales regions, apart from QNI.

Approximately 180 MW of embedded generation or demand management in addition to that presently committed would need to be installed in each of the Gold Coast and far north eastern NSW areas to alleviate the emerging network constraints in those areas. The location for this generation would be ideally suited from a system viewpoint at or near Lismore or Terranora substations in NSW and Mudgeeraba, Burleigh or Molendinar substations in Queensland.

BRW’s opinion is that, currently there are significant impediments to the implementation of demand management, and additional embedded generation in this region is unlikely.

The successful implementation of demand management is unlikely for the following reasons:

- Low numbers of large industrial or commercial customers exist in the area that would actively participate in demand side management;
- Practicalities of establishing voluntary load shedding schemes for residential and commercial customers in the area given the sheer number of customers required to form a load shedding block. 180 MW is equivalent to approximately 60,000 customers. Therefore contracting manageable numbers of customers in load shedding blocks sufficient to provide 180 MW capacity would be unlikely
- Historical lack of take-up from major customers in many areas of Australia in offering unplanned load shedding. Some distribution businesses[16] have pro-actively tried to contract demand-side management with businesses in return for network deferment benefits - but without success. Typical feedback from large businesses is that whilst planned demand reduction may be attractive, the cost of lost production and wastage of an unplanned demand reduction is not sufficiently compensated by network deferral payments.

[16] United Energy Limited (circa 2000) was one example where the feasibility of implementing demand management for network augmentation deferment had been explored and discussed with its major customers with a scheme offering network support payments.

The implementation of additional embedded generation in this region is very difficult for the following reasons:

- Limited availability of fuel sources in the region (particularly gas supply for gas powered generation). Gas turbine plant is ideal for operating at peak periods, taking advantage of potentially high pool prices, and concurrently deferring potential network augmentation. Installation of gas turbines to meet the 180 MW target is unlikely without potential major gas pipeline augmentations;
- Limited scope for increased cogeneration in the sugar industry in the Tweed and Gold Coast regions and a possible decline in sugar cane production in these regions despite the recently announced government support initiatives for the industry;
- High environmental sensitivity of the region makes it very difficult to obtain planning permits for new generation plants;
- Augmentation of the distribution networks may be required to accommodate embedded generation particularly generation plants of large size or remote locations where the network may be relatively weak. The addition of generators to a network can also increase rupture levels. Once these levels exceed the ratings of equipment in a distribution network, the network costs of adding generation could be substantial. This can impede entry of embedded generation due to the high connection costs.

Given the nature of the areas, customers with substantial amounts of load available for shedding do not exist to cover 180 MW for each state. Therefore any demand management alternative would need to be supported by embedded generation.

Load forecasts presently published by the NSPs already take into account committed and known proposed embedded generation and demand side management schemes. Alternative 6 would need to include very significant embedded generation and demand side management schemes over and above that currently envisaged by the NSPs.

3.8.2 Definition of Services Provided by Alternative 6

3.8.2.1 Active Power Flow Capability

As Alternative 6 contains no interconnection between the two Queensland and New South Wales regions except the existing QNI, no additional active power transfer between the regions would be made possible by Alternative 6.

Alternative 6 would have to have sufficient capacity of installed embedded generation in each region and sufficient contracted load shedding to alleviate the emerging network constraints in the Gold Coast and far north eastern NSW areas.

3.8.2.2 Reactive Power Flow Capability and Voltage Control

Generators of the synchronous type are able to provide localised reactive power support when required and maintain local voltage levels. Induction generators, if used, would need to be provided with power factor correction capacitors and would provide no voltage control ability.

3.8.2.3 Deferment of Capital Investment

Generators, if placed in key locations on the network, could potentially defer both the transmission and distribution system augmentations proposed by TransGrid, Powerlink, Energex and Country Energy. Such arrangements have proved to be very difficult to implement elsewhere and the difficulties could be expected to be magnified in the subject region due to both environmental sensitivities and the lack of a suitable fuel source.

3.8.3 Not a Reasonable Alternative

Alternative 6 provides no increase in interconnection capability between Queensland and NSW. Alternative 6 would address some of the present network constraints in the far north eastern area of NSW and the Gold Coast.

BRW concludes that significant impediments to the implementation of Alternative 6 render it technically and economically infeasible at this time and, therefore, Alternative 6 is not a reasonable alternative for the purpose of applying the Regulatory Test and has not been considered in further detail in this report.

4 NETWORK DEFERRALS

This section discusses the network deferments associated with reliability augmentations. System stability augmentation benefits are discussed in Appendix A. The network deferments and economic benefits of each alternative project have been provided to ACG to be included in the Regulatory Test.

4.1 Regional Load Forecasts

Table 4.1 lists the regional growth forecasts used by BRW in its modelling. Load forecasts up to 2012/13 were determined from the TNSP 2003 annual planning reviews. Load forecasts post 2012/13 were based on BRW's assessment of the projected loads. BRW has assumed linear growth at 25 MW per year for the Gold Coast and 15 MW per year for the North East of NSW post 2013.

Table 4.1 – Load Forecasts – Expected Economic Growth Scenario (50% POE).

Year	Gold Coast / Tweed MW	Growth MW	Growth %	Far NE NSW MW	Growth MW	Growth %
2005/6	687	30	4.6	560	14	2.5
2006/7	712	25	3.6	575	14	2.5
2007/8	731	19	2.7	589	14	2.5
2008/9	757	26	3.6	603	15	2.5
2009/10	779	22	2.9	619	16	2.6
20010/11	803	24	3.1	634	15	2.5
20011/12	828	25	3.1	650	15	2.4
20012/13	855	27	3.3	666	16	2.4
20013/14	*880*	*25*	*2.9*	*681*	*15*	*2.2*
20014/15	*905*	*25*	*2.8*	*696*	*15*	*2.2*
20015/16	*930*	*25*	*2.8*	*711*	*15*	*2.2*
20016/17	*955*	*25*	*2.7*	*726*	*15*	*2.1*
20017/18	*980*	*25*	*2.6*	*741*	*15*	*2.1*
20018/19	*1005*	*25*	*2.5*	*756*	*15*	*2.0*
20019/20	*1030*	*25*	*2.5*	*771*	*15*	*2.0*

Note: In the period 2006-8 the growth on the Gold Coast is lower than other years due to the transfer of load out of the Gold Coast area to the new 110 kV Coomera substation, proposed to be established for growing Energex loads north of the Gold Coast. This load is being taken off surrounding substations in the Gold Coast region. Although Coomera is outside the defined Powerlink Gold Coast area, BRW has included the new load at Coomera in the modelling. The diversity factor between regional and zone forecasts have been taken into account when allocating these forecast demands to the individual bulk supply points used in BRW's modelling. BRW has confirmed the bulk supply point demand allocation and load flow assessment with Powerlink's own 2006/7 assessment.

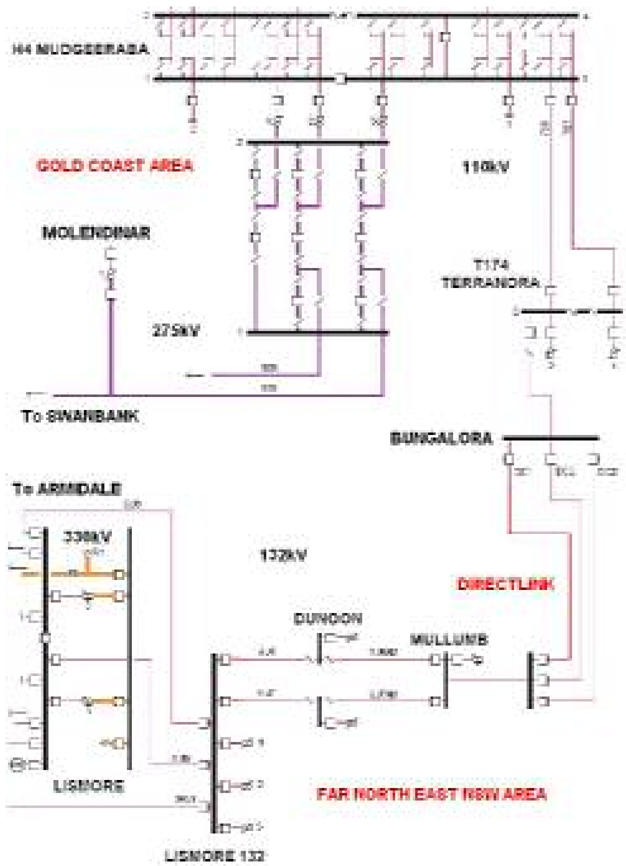
Load forecasts presently published by the NSPs already take into account committed and proposed embedded generation and demand side management schemes.

BRW has estimated load forecasts from 2013/14 as these are outside the planning horizons for the TNSPs. Load forecasts post 2013/14 are speculative, however BRW has assumed constant megawatt growth (linear growth) which is typically observed for a developed urban area and consistent with the present TNSP growth forecasts up to 2013.

The regional boundaries defining these load forecasts are as follows. Gold Coast / Tweed area load forecasts includes 110 kV load supplied from the 275 kV Mudgeeraba and Molendinar substations plus the flow on the Cades County – Molendinar 110 kV line. Far North Eastern NSW area load forecasts includes 132 kV load supplied north of and including Tamworth, and, north of and including Coffs Harbour.

4.2 System Diagram

Directlink's connection to surrounding network as at March 2004 is shown below.



4.3 Queensland Transmission Network Constraints

Powerlink and Energex have identified emerging network limitations in the Gold Coast and Tweed areas of south-east Queensland. The primary concern of the Queensland Network Service Providers is that, without corrective action, a reliable power supply may not be able to be maintained from the summer of 2005/06 in the event of an outage of one of the 275 kV transmission lines (805 or 806) between Swanbank Power Station and Powerlink's Mudgeeraba 275 kV/110 kV substation and Molendinar 275 kV/110 kV substation, coincident with the summer peak load period. Under these circumstances, it is expected that voltage stability limits will be exceeded, resulting in the need for customer load shedding to prevent voltage collapse and re-establish secure operation of the system.[17]

BRW has identified a number of network constraints in the Gold Coast area over the analysis period consistent with Powerlink's findings. In 2005/6 these include:

1. Loss of Mudgeeraba – Broadbeach 110 kV line 779 or 780 with load above the continuous rating on the other corresponding line. Loading remains within the emergency rating.
2. Loss of Swanbank – Mudgeeraba 275 kV line 805 with load above the continuous rating on lines 806 (Swanbank – Molendinar/Mudgeeraba 275 kV line), 787 and F837 (Loganlea – Beenleigh 110 kV lines), and load above the emergency rating on and on line 704 (Beenleigh – Cades County 110 kV line). Voltages to the Gold Coast are outside acceptable limits.
3. Loss of Swanbank – Mudgeeraba/Molendinar 275 kV line 806 with load above the continuous rating on lines 805, 787 and F837, and above the emergency rating on line 704. Voltages to the Gold Coast outside acceptable limits. The loss of line 806 provides the most severe condition.

Powerlink has advised BRW that the power factor of the 110 kV network (excluding existing capacitors connected at 110 kV) in 2006/7 averages at 0.92 at peak demand (i.e. 313 MVAr on a 712 MW peak load). Furthermore, Directlink is currently contracted by NEMMCO for reactive power support for the system under an ancillary services agreement utilising up to 55 MVAr of Directlink's capability until June 2005. BRW has assessed for its alternative projects that additional reactive plant installation is required. A power factor of 0.97 (i.e. 180 MVAr load) would be prudent given the voltage constraint issues that presently exist on the Gold Coast. A power factor of 0.97 at 110 kV would raise the power factor of the 275 kV network supplying the Gold Coast from 0.96 to near unity at Swanbank once the existing capacitors at 110 kV and 275 kV are taken into consideration with line losses. Therefore BRW has included an additional 150 MVAr of capacitors distributed throughout the 110 kV network of the Gold Coast in the Alternative projects to extend the deferment times and to release Directlink's reactive power capability for post-contingent support. This is estimated to cost $A4.0M. The optimum location for these banks is as follows: 50 MVAr at Broadbeach or Surfers Paradise, 50 MVAr at Southport or Molendinar, 25 MVAr at Robina, and, 25 MVAr at Nerang. These are only suggested locations, but locations towards the north end of the Gold Coast are more appropriate at either the 110kV or lower voltage levels to free up capacity on lines 779 and 780. This reactive plant would be rolled into the asset base of either Powerlink or Energex.

[17] Powerlink and Energex RFI titled "Emerging Transmission Network Limitations – Electricity Transfer to the Gold Coast and Tweed Area" – August 2003

4.4 NSW Transmission Network Constraints

TransGrid and Country Energy have carried out joint planning investigations that have identified emerging network limitations in supplying the far north coast of New South Wales from the Armidale 330 kV supply. The primary concern of the NSW Network Service Providers is that without corrective action, a reliable power supply may not be able to be maintained from winter 2006 in the event of an outage of the 330 kV transmission line (line 89) between Armidale and Lismore 330 kV/132 kV substation, coincident with the winter peak load period. Under these circumstances, it is expected that voltage regulation limits will be reached and that customers will be exposed to unacceptably low voltage conditions, particularly around the lower north coast area.[18]

BRW has identified a number of network constraints to the far north coast of NSW over the analysis period consistent with Country Energy and TransGrid's findings. These include:

1. Loss of Armidale – Coffs Harbour[19] 330 kV line 89. 132 kV lines 966 and 96C become overloaded for loss of line 89. Depressed voltages also appear on the NSW Lower North Coast.
2. Loss of Mudgeeraba – Terranora 110 kV line 757 or 758. The corresponding line becomes overloaded (considering load at Terranora only).
3. *Loss of Muswellbrook – Tamworth 330 kV Line 88*
4. *Loss of Liddell – Muswellbrook 330 kV line 83*
5. *Loss of Liddell – Tamworth 330 kV Line 84*
6. *Loss of Armidale – Tamworth 330 kV Line 85*
7. *Loss of Armidale – Tamworth 330 kV Line 86*

Note: Overloads on conditions 3 – 7 are strongly dependant on QNI flows and generally combined QNI and Directlink flows would be restricted to pre-contingent mode to avoid overload conditions. Therefore conditions 3 – 7 are not included in the BRW modelling.

BRW has noted in its modelling that there are substantial network limitations in the area adjacent to the NSW far north coast, that is, in the area of the NSW lower north coast, south of and including Coffs Harbour. TransGrid has confirmed that this constraint exists and is addressing the issue with the installation of 330 kV transformation at Coffs Harbour prior to 2005. It is BRW's opinion that Directlink would not be able to assist in any significant way to the constraints in the lower north coast and has therefore not sought to defer the installation of this transformer.

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[18] TransGrid and Country Energy document titled "Emerging Transmission Network Limitations on the NSW Far North Coast" – August 2003

[19] Presently line 89 connects Armidale with Lismore. TransGrid intend to switch Coffs Harbour into this line prior to the identified deferrals. BRW has assessed that this augmentation is required now to support voltage levels to the NSW Lower North Coast.

4.5 Methodology for Determining Deferment Periods

BRW recognises that the TNSPs have Code obligations to plan and operate their networks to achieve network performance standards such as those set down in Schedule 5.1 and under state regulations.

BRW's analysis of the networks for the far north east NSW and Gold Coast networks indicate that at present, an (N-1) approach is not presently being implemented in these networks - instead the networks are being operated with some level of risk – i.e. these networks are operated above (N-1).

A standard methodology for determining the timing and selection of network augmentations based on a network operating above (N-1) is to use a net market benefits test as a method of ranking augmentation options based on avoided energy at risk.

It would not be equitable to assess the Directlink Application on an (N-1) approach over the entire proposed deferment period, given the assets are presently operating above (N-1), in some scenarios by substantial amounts[20]. In order to assess Directlink and the alternative projects on an equal basis, BRW has taken the approach that the calculation of the deferment period be based upon adopting a risk level at the end of the deferment period no greater than that adopted by the local TNSP in the year of the planned augmentation had the augmentation not proceeded. This means that Directlink or the alternative projects, when providing network support, may be able to provide an (N-1) result at the start of the deferment period, but not necessarily at the end of the deferment period. Regardless, the level of energy at risk adopted is no greater than that adopted by the TNSPs.

For system normal operation BRW has assumed that all plant is operated within its continuous rating and that SVC equipment is operating nominally around zero output[21].

To define the risk level the TNSP is operating at in the year of the augmentation, the following calculation was performed:

[20] BRW has noted for the 2004 year, substantial overloads exist above the emergency short time rating on line 704 for loss of either line 805 or 806.

[21] BRW has assessed the system based on a comparison of 'Without the Alternative Project' against 'With the Alternative Project'. In the former case, it was assumed that Directlink does not exist at all and therefore the active power flows between the far north east of NSW and the Gold Coast are assumed to be zero and reactive power support is zero. In the latter case, the extent to which flows on the alternatives need to be scheduled will depend on acceptable voltage depression levels immediately following the most critical contingency, prior to the operation of the post contingency support, and the guaranteed speed of response of the post contingency support. BRW provides recommended levels and performance times it considers reasonable, however levels and guaranteed response times endorsed by the relevant planning authorities and NEMMCO would need to be adopted. Depending upon the levels adopted, this voltage constraint may fall below thermal constraints, particularly in later years of the deferment period. This is however not applicable if response times of the post contingent support are of the order of SVC type response times.

Calculate for the critical contingency in the year of the planned augmentation, the:

1. voltage deviations before transformer tapping;
2. voltage deviations after transformer tapping;
3. thermal overload after transformer tapping;
4. reactive reserve margin.

This calculation defined the benchmark for calculating the deferment period.

To determine the deferment period, the calculation was repeated, this time with the network support service in place. The load was increased year by year according to the expected load growth forecast. The deferment period was then limited by any one of the following constraints:

1. voltage deviations before the network support service response and before transformer tapping was limited to -30% (see below);
2. voltage deviations before transformer tapping was limited to -10% with the network support service in place;
3. voltage deviations after transformer tapping was limited to -5% with the network support service in place;
4. net thermal overload after transformer tapping was limited to the TNSP adopted risk calculated above;
5. reactive reserve margin at 1% of fault level[22].

Deferment periods were selected on the basis that flows on QNI would not need to be adjusted to cater for the critical contingency. QNI's present capability has been used in all of the BRW studies[23].

To minimise the risk of contention regarding the speed of response of the network support service, BRW recommends the support service responds within the times given in Table 4.5(a). Based on the industry standard ITIC-2000 power quality curve, this table represents "typical" electrical equipment's ride-through capability for a given voltage excursion without interruption or damage. BRW assesses that a network support service

[22] BRW notes that in years prior to the Powerlink augmentations to the Gold Coast, the reactive reserve margin to the Gold Coast is below the 1 % of fault level value. To add in the cost of additional reactive plant in later years of the deferment or to shorten the deferment period of the alternative projects in order to achieve the 1 % value would unfairly bias against Directlink or the alternative projects. Therefore BRW has assumed the cost of additional reactive plant above that specified in the alternative projects would be borne by the NSPs.

[23] TransGrid and Powerlink have prepared a report (issued through NEMMCO) that discusses options for upgrading QNI. This report dated 19th March 2004 and titled "Benefits of Upgrading the Capacity of the Queensland to NSW Interconnector", states that only marginal increases in QNI's capability are currently economic. BRW has assessed that the marginal capability increases should have negligible impact on the calculated deferment periods in this report.

that is capable of responding faster than these times will be more than adequate to satisfy any local code requirements.

Table 4.5(a) – Response times of Network Support Service to Voltage Disturbances

Voltage Depression	Maximum bound response time	Minimum bound response time
Up to 10% of nominal	60 seconds	10 seconds
Greater than 10% but less than 20%	10 seconds	0.5 seconds
Greater than 20% but less than 30%	0.5 seconds	0.02 seconds
Greater than 30%	0.02 seconds	0 seconds

It is unlikely any service could respond in time for voltage deviations greater than 30 %, therefore the deferral period is limited to the practical speed of response that the support service can deliver. In the case of a post-contingent Directlink, the Directlink owners have advised the voltage control aspect of Directlink operates in performance times similar to an SVC and therefore response times up to 0.5 seconds are achievable. Therefore BRW has assigned a limit of 30 % to the initial voltage dip using a wost case load model that assumes 65 % constant power load and 35 % constant impedance load in the final deferment year. The size of the voltage excursion depends significantly on the selection of load model. Load models based on *constant impedance* loads would give an optimistic view of the voltage excursions, whereas load models based on *constant power* loads would give a pessimistic view. BRW believes that the load model selected conservatively represents the load in the region. Table 4.5(b) shows the assumed response times for network overload conditions.

Table 4.5(b) – Response times of Network Support Service to Network Overloads

Overload	Maximum bound response time	Minimum bound response time
Above continuous rating but below emergency short time rating.	10 minutes	10 seconds
Above emergency short time rating	10 seconds	0 seconds

BRW has taken the conservative approach in its modelling in that the Gold Coast and far north east NSW loads peak at the same time.

4.6 Summary of Network Analysis Results

This section summarises the network operating conditions in NSW and Queensland at the beginning and end of the deferment periods for Alternative 0's deferral of the first tranche of projects.

Queensland Region LOSS OF LINE 806	2005/6 Without Alt 0	2005/6 With Alt 0	2010/11 With Alt 0
Voltage deviations (delta %)			
before support service operates	-22.1%[24]	-10.0%[25]	-30.0%[26]
before transformer tapping	-22.1%	-2.5%	-10.0%[27]
after transformer tapping	-13.0%	0.0%	-2.6%

[24] Load is 95% constant power, 5% constant impedance to allow load flow convergence. Load flow does not converge at 100% constant power load.

[25] Load is 95% constant power, 5% constant impedance to limit voltage dip to 10%. The difference in voltage deviation is due to the additional reactive support implemented in the Gold Coast. A 100% constant power model still gives a satisfactory result well within the 30% voltage dip limit.

[26] Load is 65% constant power, 35% constant impedance to limit voltage dip to 30%.

[27] Load is 90% constant power, 10% constant impedance to limit voltage dip to 10%. This load model was selected to gauge the load mix to give the maximum allowed voltage deviation. Using a 65% / 35% ratio as above would provide a much lower voltage dip than 10%.

Queensland Region	**2005/6**	**2005/6**	**2010/11**
LOSS OF LINE 806	**Without Alt 0**	**With Alt 0**	**With Alt 0**
Thermal overload (MW)			
support service receiving end flow	n/a	160	140
plant above continuous rating			
Line 805	153.5	0.0	110.6
Line 704	123.8	28.2	103.8
Line 787	29.2	0.0	23.5
Line F837	29.2	0.0	23.5
Line 779	0.0	10.3	21.6
Line 780	0.0	10.3	21.6
load at risk above continuous	**277.3**	**38.5**	**214.4**
plant above emergency rating			
Line 704	82.8	0.0	60.8
load at risk above emergency	**82.8**	**0.0**	**60.8**
Reactive reserve (MVAr)			
alternative 0	n/a	45	0
other	0	125	0
shortfall	*125*	*0*	*15*
net margin	**-125**	**170**	**-15**[28]

[28] Assumes no reactive plant added since 2005/6. Margin will be 1 % of fault level (i.e. 50 MVAr) if 65 MVAr of reactive plant is installed over the deferment period by the NSPs.

New South Wales Region	**2006**	**2006**	**2013**
LOSS OF LINE 89[29]	**Without Alt 0**	**With Alt 0**	**With Alt 0**
Voltage deviations (delta %)[30]			
before support service operates	0.0%[31]	0.0%	0.0%
before transformer tapping	0.0%	0.0%	0.0%
after transformer tapping	0.0%	0.0%	0.0%
Thermal overload (MW)			
support service receiving end flow	n/a	90	70
plant above continuous rating			
Line 96C	29.1	0.0	29.4
Line 966	16.3	0.0	15.8
load at risk above continuous	**45.4**	**0.0**	**45.2**
plant above emergency rating			
Line 96C	19.2	0.0	19.4
load at risk above emergency	**19.2**	**0.0**	**19.4**
Reactive reserve (MVAr)			
alternative 0	n/a	75	0
other	170	170	117
shortfall	*0*	*0*	*0*
net margin	**170**	**245**	**117**

[29] Coffs Harbour 330 kV/132 kV transformer assumed to be in service over the entire analysis period and is fully switched into Line 89 (i.e. loss of transmission line does not also result in loss of transformer). Loss of line 89 represents the section of 330kV line between Armidale and Coff's Harbour which results in the worst case condition.

[30] 100% constant power loads assumed for all NSW studies. A less conservative load model was not required.

[31] SVC at Lismore assumed to have responded.

4.7 Queensland Transmission Network Reliability Projects

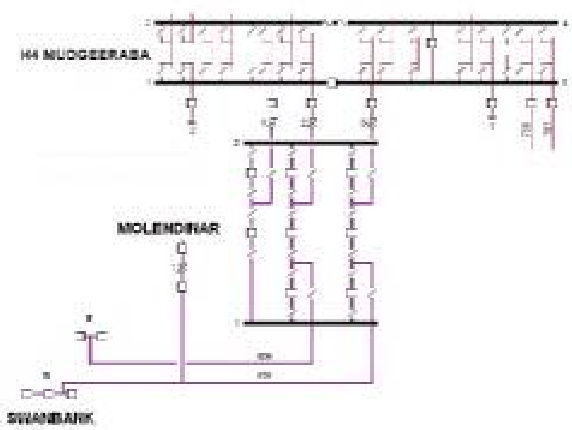
One option Powerlink is considering to address the constraints identified in the Gold Coast is the establishment of the 275 kV Greenbank substation with a 120 MVAr capacitor bank and a 275 kV new transmission line from Greenbank to Molendinar 275 kV with a 275 kV/110 kV transformer at Molendinar[32]. This is similar to the augmentation to the Gold Coast as identified in Alternative 5 with the exception that BRW has retained the 806 tee and used only a new single circuit, whereas Powerlink propose a double circuit line and removal of the 806 tee. In 2003, Powerlink established Molendinar 275 kV with a teed 275 kV line to Maudsland to connect into the existing Swanbank – Mudgeeraba 275 kV line (806) to provide additional transformation capacity into the area. This teed line is a temporary arrangement and shall be augmented with the Greenbank – Molendinar 275 kV line in 2005/6 under the Powerlink proposal.

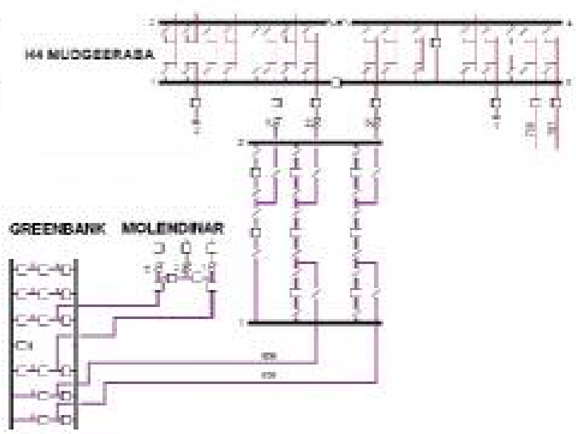
BRW has assessed that the proposed Greenbank – Molendinar 275 kV augmentation is a valid augmentation for improving supply to the Gold Coast, yet could be deferred by a number of years with Directlink providing post-contingent support and power factor correction in the Gold Coast.

BRW has identified further constraints to the Gold Coast area by 2015 beyond the existing planning horizon. This is the second tranche of augmentations to the Gold Coast. At this time the likely preferred augmentation will be a second Greenbank to Molendinar circuit (if not established earlier) with a third transformer installed at Molendinar. Additional switchgear will be required at Greenbank and Molendinar. Directlink with post-contingent support could potentially defer this augmentation.

Proposed Gold Coast QLD 275kV systems

In 2005 Following Tranche 1and 2





[32] Powerlink has advised BRW in a meeting at Powerlink's offices that the Molendinar transformer would be required at around the same time as the Greenbank augmentation. Whilst the timing of this transformer is not yet firm at the time of publication, Powerlink have advised that the variation in the timing of this transformer would be no more than one year later.

Table 4.7(a) – Queensland Project Capital Costs (not including IDC)

Project Capital Cost (in 2005 AUD)	**First tranche** 2005/06 Proposed Greenbank – Molendinar 275 kV transmission line and substation*	**Second tranche** 2014/15 Proposed Second Greenbank – Molendinar 275 kV line and transformer
BRW Estimate	$59.0M	$38.2M
TNSP Estimate	$48.9 + $6.2M [33]	Not Available

[33] Source : "Application Notice – Proposed New Large Network Asset – Gold Coast and Tweed Areas" – Powerlink and Energex, 19th April 2004. Powerlink have costed the Greenbank lines and Molendinar transformer projects separately and have not included cost of easements.

Table 4.7(b) shows the extent to which the relevant network reliability augmentations in Queensland would be deferred up until 2020 for the market development scenario driven by the medium economic load growth scenario[34].

Table 4.7(b) – Queensland Deferral Periods[35] – Medium Economic Growth Market Development Scenario

Projects	First tranche 2005/06 Proposed Greenbank – Molendinar 275 kV transmission line and substation*	Second tranche 2014/15 Proposed Second Greenbank – Molendinar 275 kV line and transformer
Base Case: Directlink with Pre-Contingent Support	Up to 1 year deferral 2006/7	0 year deferral 2014/15
Alternative 0: Directlink with Post-Contingent Support	5 year deferral 2010/11	4 year deferral 2018/19
Alternative 1: Modern HVDC Light®	5 year deferral 2010/11	4 year deferral 2018/19
Alternative 2: HVDC Conventional	5 year deferral 2010/11	4 year deferral 2018/19
Alternative 3: AC Link with Phase Shifting Transformer	2 year deferral 2007/8	1 year deferral 2015/16

* Note: Due to lead time constraints, it is unlikely Powerlink will be able to establish Greenbank and the new 275 kV line by summer 2006. The preferred option Powerlink are proposing is to contract with Directlink for one year, or alternatively, install the Double tee in Maudsland in 2005/6 then the Greenbank-Molendinar line for 2006/7 with a second transformer at Molendinar at around the same time. The proposed Directlink support or double tee project is a short term temporary option by Powerlink to defer the Greenbank-Molendinar line by one year. Given this, BRW has ignored the Double Tee project and advanced Greenbank – Molendinar by one year to represent what would have been implemented by Powerlink had sufficient lead time been available.

[34] Expected Load Forecasts for the Gold Coast (including Tweed area) were obtained from Powerlink's 2003 Annual Planning Review.

[35] The extent to which these deferments can be realised shall depend on the availability and reliability of each alternative project. BRW has assumed identical availability and reliability levels for all of the alternative projects, at levels typically observed for overhead transmission lines.

Table 4.7(c) shows the extent to which the relevant network reliability augmentations in Queensland would be deferred up until 2020 for the market development scenario driven by high economic growth. High growth rates are not published for the Gold Coast therefore BRW has calculated the high growth rates by scaling up the medium growth rates for the Gold Coast in proportion to the published Queensland high growth scenario forecasts in the NEMMCO 2003 Statement of Opportunities. The second tranche of projects needs to be brought forward to 2009/10 for a higher than expected growth scenario.

Table 4.7(c) – Queensland Deferral Periods – <u>High</u> Economic Growth Market Development Scenario

Projects	**First tranche** **2005/06 Proposed Greenbank – Molendinar 275 kV transmission line and substation***	**Second tranche** **2009/10 Proposed Second Greenbank – Molendinar 275 kV line and transformer**
Base Case: Directlink with Pre-Contingent Support	0 year deferral 2005/6	0 year deferral 2009/10
Alternative 0: Directlink with Post-Contingent Support	2 year deferral 2007/8	2 year deferral 2011/12
Alternative 1: Modern HVDC Light®	2 year deferral 2007/8	2 year deferral 2011/12
Alternative 2: HVDC Conventional	2 year deferral 2007/8	2 year deferral 2011/12
Alternative 3: AC Link with Phase Shifting Transformer	0 year deferral 2005/6	0 year deferral 2009/10

Table 4.7(d) shows the extent to which the relevant network reliability augmentations in Queensland would be deferred up until 2020 for the market development scenario driven by low economic growth. Low growth rates are not published for the Gold Coast therefore BRW has calculated the low growth rates by scaling down the medium growth rates for the Gold Coast in proportion to the published Queensland low growth scenario forecasts in the NEMMCO 2003 Statement of Opportunities. The second tranche of projects needs to be pushed out beyond the planning horizon for a lower than expected growth scenario.

Table 4.7(d) – Queensland Deferral Periods – Low Economic Growth Market Development Scenario

Projects	First tranche 2005/06 Proposed Greenbank – Molendinar 275 kV transmission line and substation*	Second tranche Not required prior to 2020
Base Case: Directlink with Pre-Contingent Support	1 year deferral 2006/7	Not applicable
Alternative 0: Directlink with Post-Contingent Support	8 year deferral 2013/14	Not applicable
Alternative 1: HVDC Light®	8 year deferral 2013/14	Not applicable
Alternative 2: HVDC Conventional	8 year deferral 2013/14	Not applicable
Alternative 3: AC Link with Phase Shifting Transformer	3 year deferral 2008/09	Not applicable

4.8 NSW Transmission Network Reliability Projects

One option TransGrid is considering in addressing the constraints in far north east NSW is the establishment of the 330 kV new transmission line from Dumaresq to Lismore. This is the NSW augmentation as defined in Alternative 5. Prior to 2006, TransGrid will establish 330 kV transformation at Coffs Harbour by cutting into the 330 kV line between Armidale and Lismore (89) with full circuit breaker switching and a corresponding upgrade of the line rating to at least 700MVA to provide voltage support to the NSW Lower North Coast. The new 330 kV line from Dumaresq to Lismore will improve security and quality of supply to the Lower and Far North Coast areas of NSW by establishing a 330 kV ring.

BRW has assessed that the proposed Dumaresq – Lismore 330 kV augmentation is a valid augmentation for improving reliability and quality of supply to the North Eastern NSW network, yet could be deferred by a number of years with Directlink providing post-contingent support.

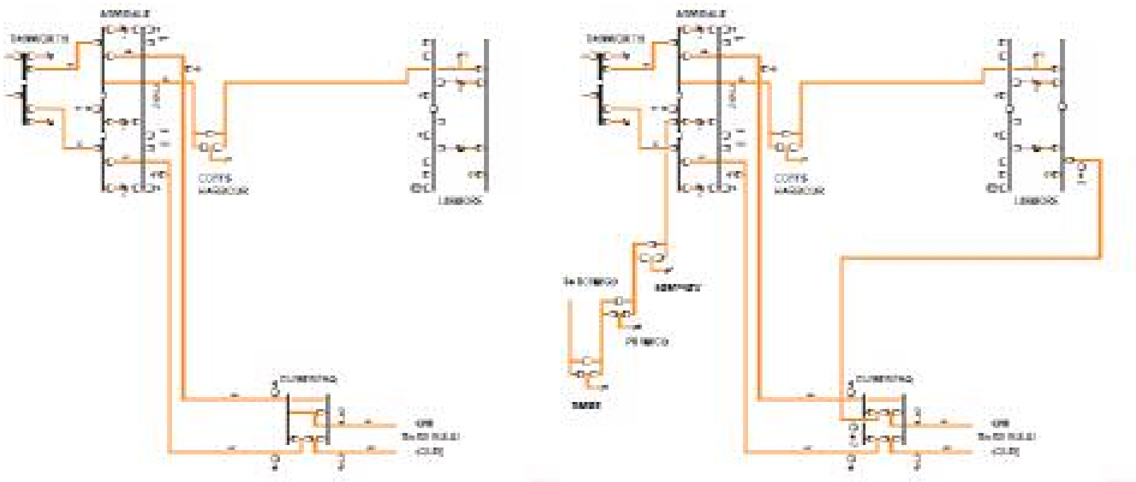
Country Energy has identified a thermal constraint on the Mudgeeraba to Terranora 110 kV lines. It is expected the lines will need to be augmented by 2007/08. A likely alternative would be the development of a second bulk supply point in the Tweed area and the construction of a third circuit from Mudgeeraba plus associated interconnection to the existing Terranora bulk supply point. Country Energy has indicated the cost of this option would be between $10M and $15M.

BRW has assessed that the proposed third circuit augmentation is a valid augmentation for improving reliability and quality of supply to the Terranora network, yet could be deferred to at least 2020 with Directlink providing post-contingent support. However, BRW has determined that this augmentation would also increase Directlink's transfer south capability and provide increased inter-regional transfer capability benefits. For this reason BRW has not sought to defer this project, hence the benefits of deferment are not included.

BRW has identified further constraints to the far north east coast area by 2014. This is the second tranche of augmentations to the far north east of NSW. At this time the likely preferred augmentation by TransGrid will be a new 330 kV line from the Tomago area to Kempsey to connect up with a planned 330 kV line from Armidale to Kempsey. Directlink with post-contingent support could potentially defer this augmentation, though this deferment period is limited by the 132 kV constraints emerging at around the same time on the lower north coast of NSW. This new 330 kV AC line in NSW will provide a third 330 kV parallel path with the existing two 330 kV Liddell – Tamworth – Armidale circuits. This line will run from the Tomago area to Kempsey and excludes the proposed section from Armidale – Kempsey which TransGrid will require for NSW lower north coast support. (BRW has assessed that this section cannot be deferred by Directlink or the other Alternatives.) 330 kV transformation will be required at Taree and Port Macquarie and 330 kV switching will be required at Taree, Port Macquarie and Kempsey.

Proposed Far North East NSW 330kV systems

In 2005 Following Tranche 1and 2[36]



[36] This also shows Transgrid's Lower North Coast Upgrade not part of Tranche 1 and 2.

Table 4.8(a) – NSW Project Capital Costs (not including IDC)

Project Capital Cost (in 2005 AUD)	First tranche 2006 Proposed Dumaresq – Lismore 330 kV transmission line	Second tranche Post 2014 Proposed Lower North Coast 330 kV line
BRW Estimate	$146.4M	$158.1M
TNSP Estimate	~ $110M	Not Available

Note: TransGrid at the time of publication had not yet formally costed the first tranche augmentation and therefore the figure here was quoted as indicative only.

Table 4.8(b) shows the extent to which the relevant network reliability augmentations in NSW would be deferred up until 2020 for the market development scenario driven by medium economic growth[37].

Table 4.8(b) – NSW Deferral Periods[38] – Medium Economic Growth Market Development Scenario

Projects	First tranche 2006 Proposed Dumaresq – Lismore 330 kV transmission line	Second tranche Post 2014 Proposed Lower North Coast 330 kV transmission line
Base Case: Directlink with Pre-Contingent Support	Up to 1 year deferral 2007	0 year deferral 2014
Alternative 0: Directlink with Post-Contingent Support	7 year deferral 2013	3 year deferral 2017
Alternative 1: HVDC Light®	7 year deferral 2013	3 year deferral 2017

[37] Medium Load Forecasts for the far North East NSW area was obtained by summation of individual substations from TransGrid's 2003 Annual Planning Review.

[38] The extent to which these deferments can be realised shall depend on the availability and reliability of each alternative project. BRW has assumed identical availability and reliability levels for all of the alternative projects, at levels typically observed for overhead transmission lines.

Alternative 2: HVDC Conventional	7 year deferral 2013	3 year deferral 2017
Alternative 3: AC Link with Phase Shifting Transformer	2 year deferral 2008	0 year deferral 2014

Table 4.8(c) shows the extent to which the relevant network reliability augmentations in NSW would be deferred up until 2020 for the market development scenario driven by high economic growth. The growth rates were determined by scaling up the expected growth rates for the north east NSW area in proportion to the published NSW high growth scenario forecasts. The second tranche of projects needs to be brought forward to 2012 for a higher than expected growth scenario.

Table 4.8(c) – NSW Deferral Periods – High Economic Growth Market Development Scenario

Projects	**First tranche** **2006 Proposed Dumaresq – Lismore 330 kV transmission line**	**Second tranche** **Post 2012 Proposed Lower North Coast 330 kV transmission line**
Base Case: Directlink with Pre-Contingent Support	0 year deferral 2006	0 year deferral 2012
Alternative 0: Directlink with Post-Contingent Support	5 year deferral 2011	2 year deferral 2014
Alternative 1: HVDC Light®	5 year deferral 2011	2 year deferral 2014
Alternative 2: HVDC Conventional	5 year deferral 2011	2 year deferral 2014
Alternative 3: AC Link with Phase Shifting Transformer	1 year deferral 2007	0 year deferral 2012

Table 4.8(d) shows the extent to which the relevant network reliability augmentations in NSW would be deferred up until 2020 for the market development scenario driven by low economic growth. The growth rates were determined by scaling down the expected growth rates for the north east NSW area in proportion to the published NSW low growth scenario forecasts. The second tranche of projects needs to be pushed back to 2015 for a lower than expected growth scenario.

Table 4.8(d) – NSW Deferral Periods – Low Economic Growth Market Development Scenario

Projects	**First tranche** **2006 Proposed Dumaresq – Lismore 330 kV transmission line**	**Second tranche** **Post 2015 Proposed Lower North Coast 330 kV transmission line**
Base Case: Directlink with Pre-Contingent Support	1 year deferral 2007	0 year deferral 2015
Alternative 0: Directlink with Post-Contingent Support	8 year deferral 2014	5 year deferral 2020
Alternative 1: HVDC Light®	8 year deferral 2014	5 year deferral 2020
Alternative 2: HVDC Conventional	8 year deferral 2014	5 year deferral 2020
Alternative 3: AC Link with Phase Shifting Transformer	2 year deferral 2008	0 year deferral 2015

4.9 Emergency Control Requirements

In the calculation of the deferral benefits, BRW has assumed that Directlink, as a regulated asset, would be operated to provide network support concurrently for both the Gold Coast and the far north eastern NSW networks to alleviate the voltage and thermal constraints for the overall region. Provided the full capability of Directlink was available for most of the time, this would allow major augmentation deferrals to occur in both NSW and Queensland, on the normal design assumption that critical contingencies do not occur coincidently in both NSW and Queensland.

Presently the network constraints that exist in the regions are manifested only for an outage of a critical item of plant, not under system normal conditions. For this reason, BRW has assumed that Directlink would be operated to provide post-contingent support to the network rather than solely as a pre-contingent support service. This would lift many of the constraints presently on Directlink's capability and would enable the full capability of Directlink to be utilised if required for most of the time.

In order to achieve this level of support, fast acting control systems would need to be implemented on Directlink to adjust the real and reactive power flows on Directlink to respond to a network contingency. It is estimated that the implementation of these controls would cost up to $A4.5M and this cost has been included in the financial analysis. This initial capital cost would be borne by the Directlink owners but would be recovered over time with an increase the regulatory value of Directlink. BRW has assumed that TransGrid's planned upgrade of the communications network to Lismore[39] is complete by the time that post-contingent support is needed and that Directlink's post-contingent functionality could leverage off the TNSP communications network to enable monitoring of remote equipment by the Directlink post-contingent control systems.

The Directlink owners have indicated a preference for implementing post-contingent support as a part of the regulatory conversion. If this is the case, then the Directlink deferment period could be identical to Alternative 0 if additional reactive plant is installed in the Gold Coast.

[39] Refer to TransGrid's 2003 annual planning review. TransGrid have indicated in discussions with BRW that the communications upgrade to Lismore will occur at the same time as the Coffs Harbour 330kV transformer installation which is planned prior to 2005.

5 SELECTION AND EVALUATION OF LINE ROUTES

5.1 Introduction

A number of the alternative projects to Directlink that have been developed by BRW include a requirement for a bipolar HVDC or single circuit 132 kV AC transmission line connection between the closest end points of the NSW and Queensland electricity transmission grids, at the Mullumbimby 132 kV and Terranora 110 kV Substations, respectively.

The extent of the environmental impact mitigation measures incorporated into a new transmission line is normally decided by the proponent or the determining body as an outcome of the environment and planning approval process. BRW recognised that predicting the outcome of a long and extensive planning and environment consultation and assessment process is very difficult and there is a significant amount of uncertainty associated with the question of what route, technology and underground line sections (if any) would need to be included in a project to obtain the required environmental and planning approvals.

To identify a transmission line route that is considered would have a reasonable probability of receiving planning approval under the NSW approval processes, and with the minimum of environmental impact mitigation measures, BRW engaged URS Australia Pty Ltd, planning and environmental specialists with considerable experience in power line and other development projects for this area and other parts of NSW.

URS was also requested to identify the associated environmental and social constraints that could be expected to impact on the construction of the line and to provide advice as to the extent to which this route and possible environmental impact mitigation measures would be acceptable to the relevant planning authorities, particularly the NSW Department of Infrastructure Planning and Natural Resources (DIPNR).

URS undertook a desk-top assessment of the relevant factors to be considered, based in large part on the application of Geographical Information System (GIS) modelling using the available data covering the key factors that could be expected to influence the selection of transmission line routes within the study area. The data sources included the DIPNR and the local Byron and Tweed Shires. The extent of work possible in this initial assessment was limited by the time frame for preparation of the regulatory conversion application.

The URS report was subsequently reviewed by ERM, another leading planning and environmental specialist currently working on a number of Country Energy and other power line development projects in NSW, to provide an independent view of the issues identified.

5.2 Description of Transmission Line

An overhead transmission line would consist of concrete poles approximately 24m in height and 250m apart, supporting three high voltage conductors and an overhead earth-wire. Most poles would have a diameter of about 0.6m at ground level. The photograph below provides typical appearance details for the most common type of pole that would be used for a 132 kV AC transmission line. A HVDC transmission line pole would have a similar appearance, but would have two, rather than three, high voltage conductors.

The transmission line would require an easement of 40m width. Most vegetation within the easement would normally be removed to prevent the build up of combustible materials. Tall trees beyond the easement that could endanger the line if they fell would also be removed. 4WD vehicle access to poles is required for line maintenance, either along the easement or using alternative routes agreed with the land owner.

5.3 Description of Study Area

The study area is characterised by a relatively narrow coastal plain, with scenically complex rolling hills, river valleys and inland mountain ranges. A number of heavily forested National Parks and Nature Reserves are located in the area, which is bordered to the west by further World Heritage Listed National Parks. Agriculture, grazing, forestry, rural living, including hobby farms, alternative lifestyles, tourism and fishing are major activities in the area, which has a sub-tropical climate and the highest rainfall of any area in NSW. The North Coast railway and Pacific Highway run through the area and link the larger population areas of Byron Bay, Mullumbimby, Murwillumbah and Tweed Heads. A network of narrow roads connects the smaller towns and rural villages. The Pacific Motorway south of Tweed Heads diverts through traffic away from Murwillumbah along the western side of the coastal plain.

5.4 Ecological Issues

Ecologically, the area has a very high biological diversity, supporting more species of birds, fish, amphibians and mammals than Kakadu National Park, with similar numbers of species only matched in Australia in wet tropical areas. The high biodiversity, combined with past vegetation clearing for human activities, resulting in habitat fragmentation and removal has resulted in an extraordinarily high number of rare, vulnerable and endangered species.

As a new overhead transmission line would involve the further removal and possible fragmentation of habitat, the constraints on detailed route selection would include a requirement for extensive and detailed biological impact investigations.

ERM has confirmed the presence of high and extremely high conservation value vegetation in the affected areas of Byron Shire, as identified in the Shire Council Draft Biodiversity Study (2003), so that more detailed impact investigations would be a firm requirement for such a development.

The Byron and Tweed Shire Local Environmental Plans (LEPs) identify a number of European heritage significance and conservation areas, including items of built and natural significance. The protection of scenic quality is a strong local community objective for both Shires and has resulted in strong opposition to a number of development proposals and protracted decision making processes, including proposals for service improvement projects and other developments required to provide for the continued population expansion in the Shires. Although the siting of a transmission line could use the topographical variations and remnant vegetation as an effective means of limiting the visual impacts to a series of relatively confined locations, this could not be expected to satisfy the owners of affected properties and sections of the wider local community.

5.5 Community Issues

Since a new overhead transmission line connection between Mullumbimby and Terranora is likely to be perceived as providing minimal direct benefit to the local communities, the level of opposition could be expected to be significantly higher than for other projects with more obvious local benefits, particularly in the vicinity of the rural residential and multiple occupancy development localities near Mullumbimby and residential developments at Terranora. Also, since the DIPNR rather than the Shires would be the decision making body, with the Shires having only a consultation role in the process, the Shire Councils could be expected to align their position more closely with the strongest voices in the community, rather than adopting a mediation stance between the moderate and more extreme views. ERM has confirmed that significant and well orchestrated opposition by vocal action groups should be anticipated for this development, requiring extended project time frames, including substantial community consultation and investigation of further alternatives, further undergrounding and other impact mitigation measures.

5.6 URS Selected Route Corridor

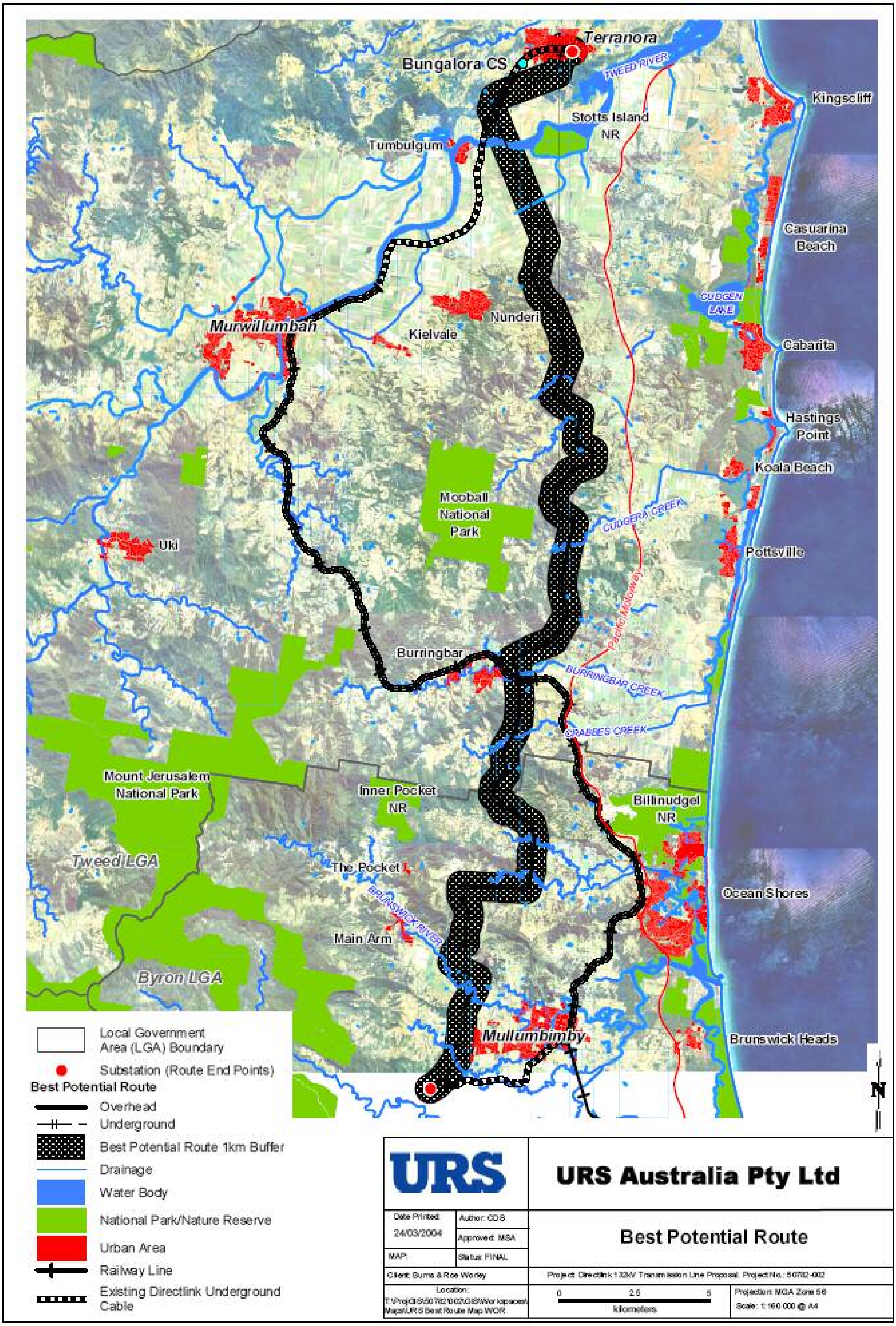
The URS assessment determined a best route that is considered to have the minimum environmental mitigation measures necessary for there to be a reasonable probability of receiving planning approval, based on the identified environmental and social constraints. URS also provided a considered view of the extent of the impact mitigation measures that would be needed to be included for acceptance by the community and the relevant planning authorities. The URS report is available on request.

Copies of the report have been forwarded to the DIPNR, Byron Shire and Tweed Shire for reference and to provide a basis for comments on the factors considered and the conclusions reached. At the time of finalising of the BRW report, only the Tweed Shire had been able to respond. The Shire confirmed that the report identified and addressed the environmental and planning issues relevant to the project and study area. The Shire also indicated that the report provided a good assessment of the issues and regulatory requirements considered significant to the project.

In determining the transmission line route corridor for the alternative projects, the principles applied by URS are summarised as follows:

- Avoid construction through World Heritage listed and other National Parks, Nature Reserves, Wetlands and Littoral (coastal) rainforests.
- Minimise clearing of remnant native vegetation and associated impacts on flora and fauna habitats.
- Avoid current and future urban development areas (by separation and undergrounding) to minimise impacts on visual amenity and lifestyle values and implement accepted power industry prudent avoidance strategies concerning community exposure to electromagnetic fields.
- Avoid identified regional and local significance European heritage sites. Any aboriginal heritage sites in the affected area are not documented.
- Locate the line to use topography and existing vegetation to limit overhead line visibility to short sections.
- Avoid areas classified as high to very high quality landscapes where possible. However, as most of the areas affected have these classifications, visual impacts cannot be avoided.
- Use underground cable in areas where multiple constraints combine to increase the sensitivity of an overhead line and no other option exists for placement of the route. For the study area, URS determined that underground cable would be required to avoid unacceptable impacts on high scenic quality protection zones identified in the Shire Local Environment Plans (escarpments near Mullumbimby and Terranora), visual amenity and lifestyle value impacts near the main urban development areas, as well as land use impacts on Tweed River valley sugar cane farming.

The best route identified by URS is shown in the following map, including the route sections where underground cable has been determined to be required. The map also shows the installed location of the existing Directlink HVDC cables.


Terranora
Bungalora CS
TWEED RIVER
Kingscliff
Stotts Island
NR
Tumbulgum
Casuarina
Beach
CUDGEN
LAKE
Murwillumbah
Nunderi
Kielvale
Cabarita
Hastings
Point
Koala Beach
Mooball
National
Park
CUDGERA CREEK
Uki
Pottsville
Pacific Motorway
Burringbar
BURRINGBAR CREEK
CRABBES CREEK
Mount Jerusalem
National Park
Inner Pocket
NR
Billinudgel
NR
Tweed LGA
The Pocket
Ocean Shores
BRUNSWICK RIVER
Main Arm
Byron LGA
Mullumbimby
Brunswick Heads
N
Local Government
Area (LGA) Boundary
Substation (Route End Points)
Best Potential Route
Overhead
Underground
Best Potential Route 1km Buffer
Drainage
Water Body
National Park/Nature Reserve
Urban Area
Railway Line
Existing Directlink Underground
Cable
URS
URS Australia Pty Ltd
Best Potential Route
Date Printed:
24/03/2004
Author: CDS
Approved: MSA
MAP:
Status: FINAL
Client: Burns & Roe Worley
Project: Directlink 132kV Transmission Line Proposal
kilometers
Projection: MGA Zone 56
Scale: 1:160 000 @ A4

5.7 Results and Conclusions

The URS findings and additional BRW and ERM comments in relation to the likely outcome of an extensive transmission line route consultation and assessment process are summarised as follows:

1. Relatively direct routes between Mullumbimby and Terranora are available within the study area that could be expected to receive planning and environmental approval from the DIPNR, subject to some constraints and inclusion of underground cable sections and other appropriate impact mitigation measures that would need to be allowed for in estimating the transmission line costs;
2. The best route would be contained within a 1 km wide corridor of approximately 47 km in length (plan view distance measurement only), of which 18 km would be required to be installed as underground cable, including 10 km at the Terranora substation end and a further 8 km at the Mullumbimby substation end.
3. An approved route would be longer than the nominated corridor, as a result of alignment changes within the corridor, as required to avoid specific localised environmental features identified by detailed on-site studies and could move outside the corridor for some locations. Additional route length is also required to allow for ground level changes not included in the plan view measurements. BRW considers that the combination of these factors could be expected to increase an actual transmission line route length by 15 % to 54 km, including 21 km of underground cable; and
4. Due to the high scenic quality of the landscapes and the high sensitivities of the local communities to visual amenity and lifestyle quality issues, significant local community opposition to an overhead line should be anticipated. This would result in an extensive and lengthy community consultation process, including a number of detailed impact mitigation studies in particular locations, including possible requirements for alignment adjustments and special vegetation plantings. Additional route length of underground cable could also be required as an end result of the consultation process, such as to avoid widespread impacts on views of particular localities or ridgelines.
5. The planning and environmental approval process would be one to two years longer for a part-overhead line route compared with a totally underground route. Additional time would be required should a proponent attempt to obtain community acceptance for an all overhead transmission line in this locality, although there would be little chance of a favourable end result.
6. With regard to threatened species and koala habitat, the proposed transmission line route would have a significant impact upon the species. As a consequence, a Species Impact Statement could be expected to be required for this route.

It is noted that the ± 80 kV DC underground cables used for the existing Directlink transmission line connection are installed largely in ducts located along the North Coast railway easement, as shown on the best route map. Since the Directlink cable route is less direct than the URS best route, the length is higher at 63 km (including

4 km of 110 kV AC cable between Terranora substation and the AC-DC Converter station at Bungalora.

Undergrounding of the 110 kV transmission line connection to Terranora substation was a requirement for Directlink due to overhead line exits congestion at the substation. The AC-DC Converter station was moved from Terranora to Bungalora because of site space limitations and local community concerns concerning the required additional infrastructure at the existing Terranora substation. The large scale and high profile residential developments with coastal views in the Terranora area have also resulted in a recent commitment by Country Energy to underground all new 66kV and 33kV subtransmission lines from the substation and the last two spans of the incoming 110 kV transmission lines. The local Terranora Action Group has also objected to recent proposals to upgrade Terranora substation, required to provide for identified electricity demand growth in the Tweed district, including a planned provision for the future installation of a 3rd substation transformer. The group seeks the relocation of the facility to another site.

Country Energy also experienced significant local opposition at the Mullumbimby end of Directlink, associated with the addition of the AC-DC converter station facilities to Mullumbimby substation and upgrading of the existing 132 kV overhead lines entering the site.

These experiences demonstrate the extent of local community sensitivities concerning above ground electricity infrastructure developments in the Byron-Tweed area and indicate that the URS findings reasonably reflect the outcome of an actual community consultation and assessment process for a transmission line connection between Mullumbimby and Terranora.

6 PROJECT COSTS

6.1 Present Value of Costs (Capital + O&M + IDC)

Table 6.1 - Present Value of the Alternative Project Costs (in Jan 2005 Dollars)

Direct Link Alternatives Cost Analysis PRESENT VALUE SUMMARY	ALTERNATIVE 0 DC INTERCONNECTION MODIFIED DIRECTLINK UNDERGROUND	ALTERNATIVE 1 DC INTERCONNECTION DC LIGHT TECHNOLOGY UNDERGROUND	ALTERNATIVE 2 DC INTERCONNECTION TRADITIONAL DC TECHNOLOGY OVERHEAD/UNDERGROUND	ALTERNATIVE 3 132kV AC INTERCONNECTION WITH PHASE SHIFTERS OVERHEAD/UNDERGROUND	ALTERNATIVE 5 QLD & NSW STATE BASED AUGMENTATIONS OVERHEAD ONLY
Component Costs (Jan 2005 dollars excl GST)	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M
PRESENT VALUE TOTAL COST	201.2	289.2	224.8	110.0	254.1
Present Value Capital Cost (including contingency)	170.4	245.2	182.2	74.4	205.4
Present Value Interest During Construction (IDC) Cost		13.2	11.8	6.8	14.8
Present Value Operations and Maintenance (O&M) Cost	30.8	30.8	30.8	28.8	33.9

Notes for Table 6.1:

1. The cost of Alternative 0 is based upon the actual capital cost of Directlink plus $4.5M for the installation of post-contingent network support capability and $4.0M for reactive plant in the Gold Coast area.
2. A contingency is included in the total estimated costs based on 10 % of the capital cost. This is included to represent a cost component that an EPC contractor would include in the price of an EPC contract given the uncertainties associated with the base costs of other components and their sources. That is, BRW has used the same approach to the pricing of an EPC contract that an EPC contractor itself would use.
3. O&M cost is the total cost over the next 40 years discounted to present values
4. IDC is an additional cost component that would be borne by the principal or an EPC contractor, depending on the payment terms of the contract. In the latter case, an IDC component would be included in the contract price. IDC has been calculated based on the following assumptions:

	Alternative 1 and 5		Alternative 2 and 3	
TIME TO IMPLEMENT	4 years		5 years	
Planning and Development	Through Years 1 and 2		Through Years 1 to 3	
Planning approval	End Year 2		End Year 3	
Easement acquisition	End Year 3		End Year 4	
Management	Years 1 through 4		Years 1 through 5	
Procurement	End Year 3	(65 % cost split)	End Year 4	(65 % cost split)
Construction	Through Year 4	(35 % cost split)	Through Year 5	(35 % cost split)

The longer implementation time used for alternatives 2 and 3 is due to the additional project development and planning approval time anticipated to establish an overhead line.

6.2 Operation and Maintenance Costs (O&M)

Table 6.2 – Summary of Operations and Maintenance Annual Expenditure (in Jan 2005 Dollars)

Direct Link Alternatives Cost Analysis O&M	ALTERNATIVE 1 DC INTERCONNECTION DC LIGHT TECHNOLOGY UNDERGROUND	ALTERNATIVE 2 DC INTERCONNECTION TRADITIONAL DC TECHNOLOGY OVERHEAD/UNDERGROUND	ALTERNATIVE 3 132kV AC INTERCONNECTION WITH PHASE SHIFTERS OVERHEAD/UNDERGROUND	ALTERNATIVE 5 QLD STATE BASED AUGMENTATIONS OVERHEAD	ALTERNATIVE 5 NSW STATE BASED AUGMENTATIONS OVERHEAD
O&M Component Costs (Jan 2005 dollars excl GST)	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M
ANNUAL TOTAL COST	2.88	2.88	2.68	1.54	1.62
General management (with assistant)	0.31	0.31	0.31	0.15	0.15
Operating management costs (1)	0.19	0.19	0.19	0.10	0.10
Operations (5)	0.61	0.61	0.61	0.31	0.31
Commercial / regulatory (1)	0.19	0.19	0.19	0.10	0.10
Financial management (with assistant)	0.21	0.21	0.21	0.11	0.11
Maintenance costs	0.36	0.36	0.29	0.29	0.36
Audit fees	0.03	0.03	0.03	0.02	0.02
Legal fees	0.05	0.05	0.05	0.02	0.02
Insurance	0.31	0.31	0.18	0.15	0.15
Energy	0.31	0.31	0.31	0.15	0.15
Communications	0.15	0.15	0.15	0.08	0.08
Corporate overheads	0.10	0.10	0.10	0.05	0.05
Other costs	0.05	0.05	0.05	0.03	0.03

Notes for Table 6.2:

1. Breakdown of Directlink's forecast O&M is based on information provided by Country Energy.
2. Maintenance costs have been pro-rata based on the complexity of the equipment.
3. Maintenance costs shown are for typical years. There will be an increase in annual costs of approximately $0.2 M over two years for some equipment replacements on a 10 year cycle.
4. Insurance costs have been pro-rata based on the capital cost of the project.
5. Debt and equity issuance costs have not been included in the forecast O&M expenditure.

6.3 Capital Costs

Table 6.3(a) – Total Capital Costs of the Alternative Projects by Component (in Jan 2005 Dollars)

Direct Link Alternatives Cost Analysis PROJECT CAPITAL			ALTERNATIVE 1 DC INTERCONNECTION DC LIGHT TECHNOLOGY UNDERGROUND	ALTERNATIVE 2 DC INTERCONNECTION TRADITIONAL DC TECHNOLOGY OVERHEAD/UNDERGROUND	ALTERNATIVE 3 132kV AC INTERCONNECTION WITH PHASE SHIFTERS OVERHEAD/UNDERGROUND	ALTERNATIVE 5 QLD STATE BASED AUGMENTATIONS OVERHEAD	ALTERNATIVE 5 NSW STATE BASED AUGMENTATIONS OVERHEAD
Project Component Costs (Jan 2005 dollars excl GST)			Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M
TOTAL COST (incl Contingency)			245.2	182.2	74.4	59.0	146.4
Contingency	%	10	22.3	16.6	6.8	5.4	13.3
PROJECT COST			222.9	165.6	67.7	53.7	133.1
Development			3.1	4.1	4.1	3.1	3.1
Approvals			5.6	6.6	6.6	5.6	5.6
Easements and Site Acquisitions			2.6	2.6	3.1	9.7	38.9
Project Management			1.3	1.3	1.3	1.3	1.3
Equipment Spares			4.1	3.0	1.0	2.5	1.7
Installed Equipment			206.3	148.1	51.6	31.5	82.6

Table 6.3(b) – Total Capital Costs of the Alternative Projects by Asset Class (in Jan 2005 Dollars)

Direct Link Alternatives Cost Analysis PROJECT CAPITAL			ALTERNATIVE 1 DC INTERCONNECTION DC LIGHT TECHNOLOGY UNDERGROUND	ALTERNATIVE 2 DC INTERCONNECTION TRADITIONAL DC TECHNOLOGY OVERHEAD/UNDERGROUND	ALTERNATIVE 3 132kV AC INTERCONNECTION WITH PHASE SHIFTERS OVERHEAD/UNDERGROUND	ALTERNATIVE 5 QLD STATE BASED AUGMENTATIONS OVERHEAD	ALTERNATIVE 5 NSW STATE BASED AUGMENTATIONS OVERHEAD
Project Component Costs (Jan 2005 dollars excl GST)			Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M
TOTAL COST (incl Contingency)			245.2	182.2	74.4	59.0	146.4
Substation			163.7	135.0	28.8	27.3	14.5
Transmission			72.5	37.0	35.0	14.9	82.9
Easements & Approvals			9.0	10.1	10.7	16.9	48.9

Notes for Tables 6.3(a) and 6.3(b):

1. A contingency is included in the total cost based on 10 % of the capital cost as explained previously.
2. Equipment spares is based on 2 % of the capital cost of the installed equipment.
3. Installed equipment costs based on the sum of the individual plant items (see Table 6.3(c)).
4. $4.5M is included for post-contingent support capability.
5. $4.0M is included for Gold Coast reactive support.
6. All other costs pro-rata based on the project complexity and easement requirements.

Table 6.3(c) – Total Capital Costs of the Alternative Projects by Equipment Type (in Jan 2005 Dollars)

Direct Link Alternatives Cost Analysis INSTALLED EQUIPMENT CAPITAL	ALTERNATIVE 1 DC INTERCONNECTION DC LIGHT TECHNOLOGY UNDERGROUND	ALTERNATIVE 2 DC INTERCONNECTION TRADITIONAL DC TECHNOLOGY OVERHEAD/UNDERGROUND	ALTERNATIVE 3 132kV AC INTERCONNECTION WITH PHASE SHIFTERS OVERHEAD/UNDERGROUND	ALTERNATIVE 5 QLD STATE BASED AUGMENTATIONS OVERHEAD	ALTERNATIVE 5 NSW STATE BASED AUGMENTATIONS OVERHEAD
Installed Equipment Costs (Jan 2005 dollars excl GST)	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M	Total Cost $M
132/110kV 200MVA Phase Shift Transformer (3 phase)					
132/110kV 200MVA Phase Shift Transformer (4x1 phase)			11.6		
132kV 50MVAr Synchronous Condenser & Transformer		4.1			
110kV 25MVAr Synchronous Condenser & Transformer		2.6			
132/110kV 200MVA Auto-Transformer (3 phase unit)					
132/110kV 200MVA Auto-Transformer (4x1 phase unit)					
132 or 110kV Switching Bay	3.7	3.7	5.5	1.2	
DC Converter station (Conventional) with Harmonic filtering and		102.0			
DC Converter station (Light)	134.7				
HVDC Underground Cable (Conventional)		19.9			
HVDC Underground Cable (Light)	57.2				
HVDC Overhead Pole Line		5.1			
132kV or 110kV AC Single Circuit Overhead Pole Line			5.1		
330kV Single Circuit Overhead Tower Line					72.4
275kV Single Circuit Overhead Tower Line				10.1	
110kV AC Underground Cable (3 x 1/c)	4.5	4.5			
132kV AC Underground Cable (3 x 1/c)			23.6		
275kV Switching Bay (breaker and half)/2				12.8	
330kV Switching bay					6.1
60MVAr 330kV Line Reactor Bank					2.0
132 or 110kV 25MVAr Capacitor Bank (excluding CB)	0.7	0.7	1.0		
132 or 110kV 50MVAr Capacitor Bank (excluding CB)	1.0	1.0	1.5		
275kV 120MVAr Capacitor Bank (excluding CB)				1.3	
275/110kV, 250 MVA Transformer				2.0	
330/132kV, 345 MVA Transformer					
New Substation Yard Establishment				1.0	
Protection and control upgrades	0.5	0.5	0.5	1.5	0.5
Emergency control systems	2.6	2.6	1.3		
Communications Upgrade	1.5	1.5	1.5	1.5	1.5

Notes for Table 6.3(c):

1. All costs include cost of purchase, delivery, installation, testing and commissioning.
2. Unit costs and quantities are provided in Table 6.3(d)

Table 6.3(d) – Installed Equipment Unit Costs and Quantities of the Alternative Projects (in Jan 2005 Dollars)

Direct Link Alternatives Cost Analysis INSTALLED EQUIPMENT QUANTITIES			ALTERNATIVE 1 DC INTERCONNECTION DC LIGHT TECHNOLOGY UNDERGROUND	ALTERNATIVE 2 DC INTERCONNECTION TRADITIONAL DC TECHNOLOGY OVERHEAD/UNDERGROUND	ALTERNATIVE 3 132kV AC INTERCONNECTION WITH PHASE SHIFTERS OVERHEAD/UNDERGROUND	ALTERNATIVE 5 QLD STATE BASED AUGMENTATIONS OVERHEAD	ALTERNATIVE 5 NSW STATE BASED AUGMENTATIONS OVERHEAD
Installed Equipment Unit Costs (Jan 2005 dollars excl GST)	Unit of Measure	Unit Cost $M	Quantity	Quantity	Quantity	Quantity	Quantity
132/110kV 200MVA Phase Shift Transformer (3 phas	no.	6.1					
132/110kV 200MVA Phase Shift Transformer (4x1 ph	no.	11.6			1		
132kV 50MVAr Synchronous Condenser & Transfor	no.	4.1		1			
110kV 25MVAr Synchronous Condenser & Transfor	no.	2.6		1			
132/110kV 200MVA Auto-Transformer (3 phase unit)	no.	1.8					
132/110kV 200MVA Auto-Transformer (4x1 phase un	no.	3.4					
132 or 110kV Switching Bay	no.	0.6	6	6	9	2	
DC Converter station (Conventional) with Harmonic	no.	51.0		2			
DC Converter station (Light)	no.	67.3	2				
HVDC Underground Cable (Conventional)	km	1.2		17.0			
HVDC Underground Cable (Light)	km	1.0	59.0				
HVDC Overhead Pole Line	km	0.2		33.0			
132kV or 110kV AC Single Circuit Overhead Pole Lin	km	0.2			33.0		
330kV Single Circuit Overhead Tower Line	km	0.3					215.0
275kV Single Circuit Overhead Tower Line	km	0.2				43.0	
110kV AC Underground Cable (3 x 1/c)	km	1.1	4.0	4.0			
132kV AC Underground Cable (3 x 1/c)	km	1.1			21.0		
275kV Switching Bay (breaker and half)/2	no.	1.3				10	
330kV Switching bay	no.	1.5					4
60MVAr 330kV Line Reactor Bank	no.	1.0					2
132 or 110kV 25MVAr Capacitor Bank (excluding CB)	no.	0.3	2	2	3		
132 or 110kV 50MVAr Capacitor Bank (excluding CB)	no.	0.5	2	2	3		
275/110kV, 250 MVA Transformer	no.	2.0				1	
330/132kV, 345 MVA Transformer	no.	3.1					
New Substation Yard Establishment	no.	1.0				1	
Protection and control upgrades	no.	0.5	1	1	1	3	1
Emergency control systems	no.	2.6	1	1	1		
Communications Upgrade	no.	1.5	1	1	1	1	1

Notes for Table 6.3(d):

1. All costs include cost of purchase, delivery, installation, testing and commissioning.
2. Unit costs in Table 6.3(d) were obtained from equipment suppliers and/or NSPs supplemented/verified against BRW's unit cost database

7 CONCLUDING REMARKS

1. BRW has identified the technical services which would be provided by Directlink as a regulated asset. These are the ability to:
   - Provide active power transfers between the participating states.
   - Select the direction of the power flow and the magnitude under wide operating conditions.
   - Provide control of reactive power flows on the interconnection independently from active power flows.
   - Provide voltage support for either end of the interconnection.
   - Provide the voltage support in a continuous rather than a “lumpy” manner.
   - Reduce system losses.
   - Provide support for QNI in the event that one or both of its circuits are lost.
   - Provide assistance in maintaining steady state equilibrium.

2. BRW has indicated the opportunity for potential enhancements[40] to Directlink that would deliver the following additional the technical services as a regulated asset. These are the ability to:
   - Defer the need for alternative capital investment.
   - Perform black-starts between states.
   - Restore supply to a network that becomes disconnected from a generation source.
   - Provide a degree of frequency control for the interconnected system.
   - Provide assistance to the interconnected system in regaining steady state equilibrium in the event that a serious system incident occurs relating to transient or oscillatory stability.

3. BRW has developed a short-list of alternative projects and considered whether they are relevantly substitutable with Directlink for the purpose of applying the Regulatory Test. These alternative projects are:
   - Alternative 0 – Directlink including post-contingent support and additional reactive plant installation in the Gold Coast area.

[40] The enhancements are at additional cost to the Directlink owners. Given that only the benefit associated with post-contingent support has been released for the Regulatory Test evaluation, BRW recommends that post-contingent support be the only enhancement implemented at this stage. System stability and black start capability enhancements could be considered in future.

- Alternative 1 – DC link using the latest HVDC Light® (or equivalent) technology with additional control functionality (including post-contingent support) and reactive plant installation on the Gold Coast. The interconnection would be totally underground.
- Alternative 2 – A conventional HVDC link using thyristor technology including post-contingent support and reactive plant installation on the Gold Coast. The interconnection would be part overhead and part underground.
- Alternative 3 – An AC link with a phase shifting transformer and post-contingent support functionality with reactive plant installation on the Gold Coast. The interconnection would be part overhead and part underground.
- Alternative 4 – An AC link with a conventional auto-transformer. The interconnection would be part overhead and part underground.
- Alternative 5 – This alternative involves the reliability augmentations of the NSW and Queensland regions to alleviate emerging network constraints due to load growth.
- Alternative 6 – This involves significant embedded generation and/or demand management schemes in the NSW and Queensland regions in addition to that already committed and proposed.

4. BRW undertook a technical evaluation of these alternatives and compared their technical performances.

5. BRW costed the above alternatives as if they were to be constructed under a competitively-priced all inclusive EPC contract. BRW used data provided by equipment suppliers and NSPs, which was supplemented and verified against BRW's in-house costing data, and an industry standard level of contingency and profit/overhead to derive a project cost based on an EPC contract price. In determining the present value of the total costs of each of the alternatives, BRW has also estimated "interest during construction" (IDC) that would be borne by the principal or the EPC contactor (in the later case an IDC component would be included in the contract price) and the cost of "operations and maintenance" of the project.

6. BRW evaluated the potential deferment periods and benefits of Directlink and each of the alternative projects using load flow models of the South East Queensland and Northern NSW networks.

8 REFERENCES

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25. "Benefits of Upgrading the Capacity of the Queensland to NSW Interconnector", TransGrid and Powerlink, 19th March 2004

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9 GLOSSARY

- AC – Alternating Current
- ACG – The Allen Consulting Group
- ACCC – Australian Competition and Consumer Commission
- BRW – Burns and Roe Worley
- Code (the) - National Electricity Code
- DC – Direct Current
- EHV – Extra high voltage (110 kV and above for the purposes of this report)
- HVDC – High Voltage Direct Current
- kV – kilo-volt
- IDC – Interest During Construction
- MW – mega-watt (a measure of active power)
- MVAr – mega-volt-ampere-reactive (a measure of reactive power)
- MVA – mega-volt-ampere (a measure of apparent power)
- NEC – National Electricity Code
- NEM – National Electricity Market
- NEMMCO – National Electricity Market Management Company
- NPV – Net Present Value
- NSP – Network Service Provider
- NSW – New South Wales
- O&M – Operations and Maintenance
- POE – Probability of Exceeding
- QLD – Queensland
- QNI – Queensland - NSW Interconnector
- SVC - Static VAr Compensator
- TNSP – Transmission Network Service Provider
- VoLL – Value of Lost Load in units of $/MWh
- VSC – Voltage Source Converter

10 APPENDIX A - INTERCONNECTED SYSTEM STABILITY

10.1 Transient Stability

The transient stability of a power system is a measure of the degree to which the power system can recover its pre-fault equilibrium following the occurrence of a fault and the clearance of the fault by the protection equipment. It is quantified by applying the hypothetical worst-case fault to the power system and determining the longest time which the worst case fault can be applied before system instability occurs.

During a fault, generators will normally accelerate because they are unable to supply all of their output power. The extent to which they accelerate is dependent on where they are relative to the location of the fault, their inertia, and what power output they were operating at prior to the fault. In general, the greater the power output prior to the fault, the greater the acceleration of the generators during a fault.

Transient stability issues arise whenever different generators on the system accelerate at different rates because this leads to a mismatch in generator frequencies when the fault is cleared.

NEMMCO has published transient stability constraint equations based on system modelling of possible system faults. The constraint equations define the amount of power that can be transferred over QNI in order that the generators in Queensland and NSW remain in synchronism after a fault.

Directlink has an impact on the transient stability constraints by regulating the flow on QNI and by impacting indirectly on other regional flows by allowing different generation dispatch patterns.

The impact on the transient stability limits is as follows:

1. By redirecting power by an amount up to Directlink's capability away from QNI, Directlink effectively increases the NSW-QLD and QLD-NSW transient stability limits by this amount.
2. By supplying power up to Directlink's rating from NSW to Queensland, Directlink effectively reduces the flow from central Queensland to south Queensland. The constraint equations indicate this can increase the QLD-NSW QNI limit by approximately 24 MW, depending on other constraints.

For power transfers in the direction of Queensland to NSW, Directlink can provide significant benefits by indirectly reducing power flows from Victoria to Snowy regions or from Snowy to NSW regions depending on the system operating conditions. Under most operating conditions, this benefit is normally in the order of a few tens of megawatts, but under unusual conditions it can raise the level of the constraint by up to 600 MW between Queensland and NSW, or not being able to transfer power across QNI at all.

10.2 Voltage Stability

Voltage stability/instability refers to the phenomenon of voltage collapse that can occur on parts of a power system after a credible contingent event, or because transmission lines are heavily loaded.

Directlink provides significant voltage stability benefits to the system. The extent of these benefits is defined by the constraint equations published by NEMMCO.

An example of a typical major benefit is the ability of Directlink to support the system voltage in the Gold Coast region following loss of a critical line.

10.3 Oscillatory Stability

Oscillatory stability is a complicated subject that is easily confused with Transient stability because of the similarity in terms, and because both subjects share several common features. However, Oscillatory stability is quite different to Transient stability, as described below.

Oscillatory stability is the capacity of an interconnected power system not to spontaneously commence under-damped internal low frequency oscillations between individual generators. That is, a power system which exhibits oscillatory stability will operate with all its generators in synchronism. It may or may not be transiently stable, depending on the fault clearance time of the worst case fault, as described earlier.

A power system which exhibits oscillatory instability may spontaneously commence under-damped oscillations between individual generators in the system. That is, a fault is not required to be applied to the network to initiate the problem. During oscillatory instability, the phase angle between affected generators will oscillate and the amplitude of the oscillations may increase to the point where the interconnected system will break up and this in turn may lead to system collapse. All of this may occur without any fault having been applied to the system.

To assess the oscillatory stability benefits of Directlink, BRW has applied the following methodology:

- A conceptual eigenvector model of the Northern NSW – Southern Queensland system was developed. This was used in conjunction with NEMMCO models available to market participants.
- An engineering assessment was made of the benefit that Directlink would contribute to the system based on these investigations.

It should be noted that because of the complex nature of this phenomenon, a detailed mathematical analysis is required in order to assess the risk posed to the system under a variety of system conditions. BRW has not attempted a full mathematical analysis for this study because of the time and resources this would require. However, a comprehensive representation of the system has been built up using data available to market participants and previous experience of such stability issues.

Systems which have shut down, at least in part, because of oscillatory stability include:

- Hong Kong- Kowloon – because of undamped oscillations with the system in China.

- Hong Kong – Kowloon – Power oscillations have been observed between Hong Kong Island and Kowloon during system tests – which required the underwater tie to be tripped between the two systems.
- Within China – several cases have been reported in which generators have been unable to generate because of oscillatory stability.
- North East coast of USA and Canada – The power blackout of the 1950's is partly attributable to oscillatory stability issues - (the more recent blackout of 2003 is still under investigation).
- In the Australian systems, power oscillations have been observed between Tarong Power station and Wivenhoe power station, and at Mungarra in Western Australia[41]. Power oscillations have also been observed on some Snowy mountain scheme Hydro generators.

The National Electricity Code requires:

> Damping of *power system* oscillations must be assessed for planning purposes according to the design criteria which states that *power system damping* is considered adequate if after the most critical *credible contingency event*, simulations calibrated against past performance indicate that the halving time of the least damped electromechanical mode of oscillation is not more than five seconds.

To assess the damping of *power system* oscillations during operation, or when analysing results of tests such as those carried out under clause S5.1.8 of the *Code*, the *Network Service Provider* must take into account statistical effects. That is the NSP must ensure that the *power system damping* operational performance criterion is complied with is that at a given operating point. This requires that real-time monitoring or available test results must show that there is less than a 10 percent probability that the halving time of the least damped mode of oscillation will exceed ten seconds, and that the average halving time of the least damped mode of oscillation is not more than five seconds.

NEMMCO have set the oscillatory stability limit for the transfer of power between Queensland to NSW at 950 MW[42], based on system studies and the availability of monitoring equipment.

The stability limit for power transfers from NSW to Queensland ranges from 630 MW to 700 MW depending on the size of the largest Queensland generator connected to the system.

The existing stability limits are somewhat arbitrary because the real system oscillatory stability limits are dependent on much more complex system conditions than are currently allowed for in the constraint equations.

[41] Reference CIGRE Report "Impact of the Interaction of Power System Controls, Status report of CIGRE TF 38.02.16"

[42] 2003 NEMMCO Statement of Opportunities

In its current state of evolution, the existing constraint equations are adequate because other constraints (e.g. thermal, voltage collapse or transient stability) are more likely to be applied before oscillatory stability constraints.

As generators and transmission lines are required to operate at higher power flow levels, the oscillatory stability limit will have to be revised downwards, possibly to the extent that it will become the major limiting constraint on transfers of power between NSW and Queensland. As this occurs it will become necessary to revise the existing constraint equations to incorporate some of the more complex issues.

Directlink can improve oscillatory stability in three distinct ways:

1. By regulating the power flow on QNI.[43]
2. By allowing a reduction in the generation dispatch levels of either Queensland or NSW [44], depending on which area is likely to experience oscillatory instability.
3. By rapidly varying the flow of power between the two states it is possible to introduce power system damping which improves oscillatory stability. Directlink can achieve this by the overt control of its power transfer, but it also provides system damping during its normal operation, without the need of additional controls.[45]

The regulation of power flow on QNI enables an additional transfer of up to the active power capability of Directlink between NSW and Queensland, assuming there is no oscillatory stability issue associated with generation dispatch.

Using Directlink to reduce generation dispatch levels can delay bringing additional units on line and defer generation projects. This has direct economic benefits to Queensland and NSW because it is more efficient to operate fewer generators at higher power levels, than to operate more generators at lower power output. The extent to which this can be achieved is directly related to Directlink's active power capability.

The system configuration of Directlink which places it in parallel with QNI means it can directly control the flow of power along QNI up to an amount equal to the active power capability of Directlink. In the event of oscillatory instability occurring between NSW and Queensland, this feature could be used to provide damping between the two states. A damping signal of a magnitude similar to Directlink's active power capability can theoretically control power oscillations that are many times this value, which is currently not a practical possibility on QNI. Directlink with appropriate controls can, for all practical purposes, prevent all possible modal oscillations between NSW and Queensland over the 10 year planning period.

[43] Increased power flows on long transmission lines generally leads to a reduction in oscillatory stability

[44] Increased generator power output generally causes a reduction in oscillatory stability

[45] Refer to ABB publication "Improvement of Subsynchronous Torsional Damping Using VSC HVDC"

10.4 Alternative Project Enhancement of System Stability

10.4.1 Alternative 0

BRW has not included control functionality to provide enhanced system stability and security in Alternative 0. With some additional capital expenditure in control and communication equipment and in backup low voltage power supplies, this functionality could be provided as a service to the NEM.

10.4.2 Alternative 1

Alternative 1 implements all of the existing Directlink control features but also includes system stability control functionality. The implementation of these additional functions are control equipment options that are provided with the HVDC Light® equipment. The incremental cost of implementing this functionality with the latest converter technology is relatively low when compared with the substantial security benefits to the interconnected network.

Alternative 1 can improve transient stability of QNI by:

- redirecting flows from QNI;
- indirectly redirecting flows between Central Queensland and Southern Queensland;
- indirectly redirecting flows between Southern NSW to Snowy regions, and between Northern Victoria to Snowy regions.

Alternative 1 can improve oscillatory stability by:

- redirecting flows from QNI;
- allowing a reduction in generation dispatch of either Queensland or NSW, depending on which regional area is more likely to experience oscillatory instability;
- varying the power flow between the two regions it is possible to introduce system damping control. Voltage source converter HVDC links achieve this to some degree without the installation of specific controls.

10.4.3 Alternative 2

Alternative 2 cannot provide support in the event of loss of generation connection to one substation nor can it provide black-start capability for loss of supply in one state.

A conventional HVDC scheme fitted with appropriate controls can be used to provide damping power to control oscillatory stability. However, there is no inherent benefit to oscillatory stability without special controls. This is in contrast to the operation of HVDC Light® which uses voltage source converters.

Alternative 2 can improve transient stability of QNI by:

- redirecting flows from QNI;

- indirectly redirecting flows between Central Queensland and Southern Queensland;
- indirectly redirecting flows between Southern NSW to Snowy regions, and between Northern Victoria to Snowy regions.

Alternative 2 can improve oscillatory stability by:

- redirecting flows from QNI;
- allowing a reduction in generation dispatch of either Queensland or NSW, depending on which regional area is more likely to experience oscillatory instability;
- varying the power flow between the two regions it is possible to introduce system damping control. Current source converter HVDC links can only achieve this via the installation of specific controls. Without specific controls, the contribution of Alternative 2 to power system damping is negative.

10.4.4 Alternative 3

Alternative 3 is able to provide power to say the Gold Coast in the event that the connection between the Gold Coast and the rest of Queensland is lost. As such, it improves the reliability of the supply to the Gold Coast and similarly to the far north eastern part of NSW.

Alternative 3 cannot respond quickly following a system incident. As noted above, the transformer tap changing mechanism and switched capacitors places significant speed constraints on its response. This response time can be minimised by using special control mechanisms, such as inverse time control, but the response is still slow, thereby limiting its effectiveness during the crucial system recovery phase following an incident.

Alternative 3 can improve transient stability of QNI by:

- redirecting flows from QNI;
- indirectly redirecting flows between Central Queensland and Southern Queensland;
- indirectly redirecting flows between Southern NSW to Snowy regions, and between Northern Victoria to Snowy regions.

Alternative 3 can improve oscillatory stability by:

- redirecting flows from QNI;
- allowing a reduction in generation dispatch of either Queensland or NSW, depending on which regional area is more likely to experience oscillatory instability.

10.4.5 Alternative 4

Alternative 4 is essentially a passive network during a system incident and cannot provide any active response to a system incident. This alternative project is able to provide power to say the Gold Coast in the event that connection to the Gold Coast from the rest of Queensland had been lost. As such, it improves the reliability of the supply to the Gold Coast and similarly to the far north eastern part of NSW. The degree of support is comparable with the support in Alternative 3.

Alternative 4 cannot directly improve transient stability of QNI, however, by redirecting flows from QNI, marginal improvement to transient stability performance may occur in some situations.

Alternative 4 cannot improve oscillatory stability except by redirecting some flow from QNI which can only be controlled via generation dispatch.

10.4.6 Alternative 5

Alternative 5 is entirely a passive network during a system incident. As such its contribution to system recovery following a system incident is negative.

Alternative 5 has a negative effect on system recovery following an incident because it permits the size of each state’s system to be increased while leaving the capability of the one interconnector (QNI) unchanged. This effectively reduces the capability of the interconnector relative to the size of the interconnected system.

Alternative 5 has a negative impact on oscillatory stability because it allows increased loading of transmission lines and generators.

With control system augmentations, Directlink may be used to modify the existing transient stability limits between NSW and Queensland. This is currently an onerous constraint on the NSW to Queensland power flow in that the transfer is limited to less than 700 MW depending on flows between Victoria/Snowy and NSW/Snowy regions. With Alternative 5, similar benefits may be obtained (subject to further study), by installing:

- Series Capacitor banks in the NSW system near Liddell power station.
- Braking resistors on the Queensland and NSW transmission systems
- Static VAr compensators (SVCs) added to both Queensland and NSW systems.

It is well documented that series capacitors can cause sub-synchronous torsional interactions between steam turbine generators, and possibly reduce the oscillatory stability limits. Therefore, BRW consider that if series capacitors were to be added in an attempt to improve transient (and some voltage) constraints they would probably require complex high speed switching arrangements to ensure that other technical issues were not inadvertently introduced. This will significantly add to the cost of this alternative project and has therefore not been included.

Braking resistors can be installed with significantly less technical risk to the system. However, this option also requires sophisticated switching devices (usually electronic), and it requires extensive engineering to optimise the required rating. The cost of these devices is similar to the cost of an SVC of similar rating.

SVCs are already installed at several locations within Queensland and NSW. However, their ability to impact on the frequency variation relating to transient stability is negligible.

Oscillatory limits are currently set to at least 700 MW for transfers from NSW to Queensland and 950 MW for transfers from Queensland to NSW. These values are not particularly well defined, and without significant study it is unclear how the limits change with different system conditions. Directlink can improve system damping with the addition of appropriate controls. In effect it can act like a generator or SVC with power system stabilizers fitted. With Alternative 5, similar benefits may be obtained (subject to further study), by installing additional SVCs, fitted with appropriate controls on the NSW and Queensland systems. The installation of series capacitors will also impact on the oscillatory limits but without significant additional study, it is unclear whether they would improve or degrade the oscillatory performance of the system.

Alternative 5 cannot improve transient and oscillatory stability of QNI or the system as a whole without fast acting reactive support.

Directlink may be dispatched as a ‘throttle’ to change the flows through QNI and the associated Queensland and NSW networks. With Alternative 5, this is not possible. To relieve thermal bottlenecks in the system, it is necessary to upgrade existing lines, or install additional lines wherever the bottlenecks occur.

In NSW, this will require upgrading long lines (e.g. Tamworth to Lismore, Muswellbrook to Tamworth etc). This is an expensive option, but it has the advantage of also increasing voltage limits operating concurrently.

Liddell being the northern most significant generator in NSW, requires that the entire network between Liddell/Bayswater and the Queensland Border must be significantly upgraded to greatly increase transfer capacity from NSW to Queensland.

Voltage limits can often be treated separately by the installation of switched reactive power shunts, such as reactors and capacitor banks. However, this will have minimal effect on thermal constraints. It should be seen as a means of deferring the upgrade of transmission links, not as an alternative.

To determine the best location for reactive support is a complex task but it is clear that existing problem areas exist on the North Coast of NSW, and the Gold Coast region of Queensland. Capacitor banks must be added in both regions to ensure that the voltage will not collapse because of single contingency events such as the loss of a transmission link.

10.4.7 Alternative 6

Only synchronous generators are able to provide dynamic support to system disturbances.

Alternative 6 may be able to improve the transient stability of QNI by reducing the requirement for flows across the link. However, under many system conditions, additional generation – particularly if it has different characteristics to existing generation – will exacerbate both transient and oscillatory stability. For the case for embedded generation, which usually consists of smaller units located near load centres, the generators will normally have significantly different characteristics to existing base load generation. Transient stability will be exacerbated by machines that have different inertia and speed of response to the system typical generation.

For Alternative 6 oscillatory stability will be exacerbated by machines that are situated close to load centres when the main source of generation is located remote from load centres.

10.5 Benefits of Interconnected System Stability Augmentations

BRW has not identified any published system stability augmentations proposed in the 10 year planning period by NEMMCO or the TNSPs. These services are usually procured from generators, for example, under ancillary services. As such, the deferral of such projects cannot be defined by BRW. However, BRW firmly believes the presence of Directlink in the interconnected system could have a substantial positive benefit on the stability and security of the system, particularly for the networks of NSW and Queensland. In order to gauge the size of these benefits, BRW has performed an assessment of the avoided risk that Directlink could bring regarding system stability issues. BRW has calculated these benefits, not to include in the Regulatory Test, but rather to assist in highlighting to the ACCC the potential significance of Directlink as playing a major role in assisting with system stability issues. BRW has not included costs which may be required to augment Directlink to provide these system stability services.

Four possible events are considered which are all low probability events but involve high consequential losses[46]. These types of event can be caused by oscillatory stability, transient stability or a combination of both.

a. Loss of the QLD – NSW interconnection. Whilst this has not yet occurred at the time of writing, inter-regional links have been lost elsewhere in the NEM, specifically:

   - Loss of the SA – VIC interconnection in December 1999
   - Loss of VIC/SA – NSW interconnection on 15 January 2001

   The financial losses for these types of events are loss of market competitiveness due to loss of inter-regional power flows, and possible loss of supply to some consumers in one state or another. For costing purposes, loss of supply was not considered for this event. It is assumed that typical market prices occur and cost of unserved energy is the market price multiplied by typical link loading of QNI.

b. Loss of the Queensland system or part thereof – this is considered more likely than the loss of the NSW system because the Queensland system is more prone to instability, and many of the generators of Queensland are located near QNI. The nearest recent equivalent event in the NEM was the loss of power to South Australia in 1999. For costing purposes a four day outage is assumed at typical loss of state load, multiplied by the VoLL rates of $10,000 per MWh.

c. Loss of NSW system or part thereof – this is a low likelihood event but it is not without precedent. BRW consider that a more likely scenario is the loss of the Northern NSW system or equipment damaging brownouts in this area. For

[46] Note: The loss of power to North East America and Canada can be considered a low probability event - it has occurred twice within a period of fifty years.

costing purposes a four day outage is assumed at typical loss of state load, multiplied by the VoLL rates of $10,000 per MWh.

d. Loss of Queensland and NSW system or part thereof – although this type of event is likely to cause the most disruption, it is probably not much less likely than the loss of Queensland or NSW separately. For costing purposes a four day outage is assumed at typical loss of both state loads, multiplied by the VoLL rates of $10,000 per MWh.

Table 10.5(a) – Summary of possible system costs per event

Event	Estimated Cost of Unserved Energy
Loss of QLD – NSW interconnection	400 MW x $20 MW/h x 24 h = $192,000
Loss of QLD system or part thereof	6000 MW x $ 10,000 MW/h x 96 h = $ 5,760 Million
Loss of NSW system or part thereof	8000 MW x $10,000 MW/h x 96 h = $ 7,680 Million
Loss of QLD and NSW systems or part thereof	$ 13,440 Million

Note: Estimates are in Feb-2004 Australian Dollars, and assume system loads are typical 2004 loads. As the system grows the cost of unserved energy will be correspondingly greater.

The probabilities applied to each event were based on engineering assessments. In arriving at the probabilities, BRW considered the cost of one major event in the periods indicated. In practice, it is more likely to have a larger number of smaller events but these are considered to be adequately catered for in the estimates presented below. The indicative value of the system stability benefits are given in Table 10.5(b) and are presented relative to Alternative 5.

Table 10.5(b) Indicative Value of System Stability to the Market

Alternative	Average Annual cost due to system failure partly due to stability reasons	Estimated annual benefit relative to Alternative 5
Alternative 0	$ 614.4 M	$1,274M
Alternative 1	$ 614.4 M	$1,274M
Alternative 2	$ 614.4 M	$1,274M
Alternative 3	$ 891.5 M	$997M
Alternative 4	$ 1,440 M	$448M
Alternative 5	$ 1,888 M	$0M
Alternative 6	$ 2,240 M	- $352M