A non-technical introduction to the ANEMMarket model of the Australian National Electricity Market (NEM)

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Abstract

In this paper, we provide an accessible introduction to our agent-based ANEMMarket simulation model of the Australian National Electricity Market. This model has been purpose built to assess the impacts of emissions trading schemes, carbon taxes and the introduction of significant new suppliers of electricity generated from low or zero carbon emitting generators. We provide an illustrative example that involves the simulation of the impacts of a range of carbon prices on the dispatch of power from different types of generators in different regional locations. From these we compute the resultant carbon reduction effects. However, these remain only illustrative simulations because they do not include a range of operative constraints that exist in reality.

1. Introduction

The ANEMMarket model is an agent based modelling framework developed for modelling the Australian National Electricity Market (NEM) is a modified and extended version of the óAgent-Based Modelling of Electricity System (AMES)ô model for the USA developed by Sun and Tesfatsion (2007a, 2007b).[1] The Australian model is called the ó.

The heuristic framework underpinning the development of the USA model by Sun and Tesfatsion was the Wholesale Power Market Platform (WPMP) which was adopted by the USA Federal Energy Regulatory Commission in April 2003. The WPMP was a complicated market design that was recommended for common adoption by all USA wholesale power markets. As such, it could be viewed as a template for operations of wholesale power markets by Independent System Operators (ISOôs) using óLocational Marginal Pricingô to price energy by the location of its injection into or withdrawal from the transmission grid (Sun and Tesfatsion (2007b, p.2)).

The WPMP market design had a high degree of complexity which led to difficulty in undertaking economic and physical reliability studies of the design using standard statistical and analytical tools (Sun and Tesfatsion (2007b, p.3)). This overriding degree of complexity suggested the applicability of the emerging powerful computational tools associated with the analysis of complexity based upon Agent-based Computational Economics (ACE) as developed, for example, in Sun and Tesfatsion (2007b).[2]

ACE is a computational study of economic processes modelled as a dynamic system of interacting agents. Thus, both the óAMESô and óANEMMarketô modelling frameworks were developed with the intension of modelling strategic trading interactions over time in a wholesale power market that was organized in accordance with core WPMP features and that operated over realistically rendered transmission grid structures (Sun and Tesfatsion (2007b, p.3)). In ACE, strategic behaviour is often modelled by adaptive learning built around reinforced learning or emergent learning and knowledge creation from genetic algorithms.

The wholesale market of the NEM is a real time óenergy onlyô market, and the market for ancillary services is treated as a separate and distinct market. Therefore, a DC OPF algorithm was used to determine optimal dispatch of generation plant and wholesale prices within the agent based model. In principle, formulation of DC OPF problems require detailed structural information about the transmission grid as well as supply offer and demand bid information from market participants.

In order to formulate the DC OPF problem, it was necessary to modify the structure of the óAMESô model in important ways in order to capture the key differences existing between the wholesale markets in Australia and the USA. The most important structural difference related to the institutional structure of the market in Australia which differed fundamentally from that in the USA. Specifically, in Australia, a

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[1] Comprehensive information including documentation and Java code relating to the óAMESô model can be found at: http://www.econ.iastate.edu/tesfatsi/AMESMarketHome.htm.

[2] Useful information and computational resources related to ACE modelling can be found at: http://www.econ.iastate.edu/tesfatsi/ace.htm.

óGross Poolô market structure was implemented whereas a óNet Poolô market structure was implemented widely in the USA. This meant that the spot market and potential role of the óday aheadô market had fundamentally different operational, procedural and legal meanings in the context of wholesale market operations in both countries.

In Australia, the spot market is the principal market in which transactions to sell and buy electrical power are made with resulting financial settlements that reflect spot market outcomes. Moreover, while day ahead bidding by generators frequently occurs and forms an important part of pre-dispatch forecasts released by the national ISO (i.e. AEMO) prior to current spot market operations, this bidding does not constitute a formal legally binding market operation with implied financial settlement protocols. The day ahead bidding helps AEMO determine and inform market participants of the óstate-of-playô with respect to the balancing of supply with demand in relation to prospective spot market operations but generators can leave their day ahead bids unchanged or change them just prior to dispatch within the operation of the spot market itself (AEMO (2009, pp. 9-13)). As such, the day ahead bidding facilitates spot market operations but does not constitute, in and of itself, a formal óday aheadô market operation with binding legal and financial implications for participants. Because of the gross pool structure underpinning the Australian market, the spot market is the key binding market legally and financially. As such, the onus for ensuring supply matches demand ultimately rests with generators who are legally required to exactly follow dispatch instructions issued by AEMO in order to match the supply of power with the demand for power in a real time setting. Because of the marked possibility of considerable spot price volatility, hedging by wholesale market participants is crucial for their long term financial viability. In section 2, we discuss how these characteristics were implemented in the óANEMMarketô program.

2. The Principal features of the ANEMMarket Model Framework.

The ANEMMarket wholesale power market framework is programmed in Java using RepastJ, a Java-based toolkit designed specifically for agent base modelling in the social sciences.[3] The ANEMMarket framework currently incorporates in stylized form several core elements of the WPMP market design that can be associated with key features of the Australian National Electricity Market. Specifically, the elements of the WPMP market design that have been incorporated into the ANEMMarket framework are:

- The ANEMMarket wholesale power market operates over an AC transmission grid for DMax successive days, with each day D consisting of 24 successive hours H = 00, 01, é .., 23;
- The wholesale power market includes an Independent System Operator (ISO) and a collection of energy traders consisting of Load-Serving Entities (LSEôs) and generators distributed across the nodes of the transmission grid;[4]

[3] RepastJ documentation and downloads can be sourced from the following web address: http://repast.sourceforge.net/repast_3/download.html. A useful introduction to JAVA based programming using the RepastJ package is also located at: http://www.econ.iastate.edu/tesfatsi/repastsg.htm.

[4] A node in the grid is a point on the transmission grid where power is injected or withdrawn.

- The ANEMMarket ISO undertakes the daily operation of the transmission grid within a one-settlement system consisting of the Real-Time Market which is settled by means of óLocational Marginal Pricingô;
- For each hour of day D, the ANEMMarket ISO determines power commitments and Locational Marginal Prices (LMPôs) for the Spot Market based on generators supply offers and LSE demand bids submitted prior to the start of day D;
- The ANEMMarket ISO produces and posts an hourly commitment schedule for generators and LSEôs that is used to settle financially binding contracts on the basis of the dayôs LMPôs for a particular hour; and
- Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMPôs associated with nodal price variation within an hour when branch congestion is triggered by ISO dispatch instructions to generators.[5]

The organization charged with the primary responsibility of maintaining the security of this power system, and often with system operation responsibilities is the Independent System Operator (ISO). The ISO is an independent organization and is assumed to have no conflicts of interest in carrying out these responsibilities.

A Load Serving Entity (LSE) is an electric utility that has an obligation, either under local law, license or long-term contract, to provide electrical power to end-use consumers (residential or commercial) or possibly to other LSEôs with end-use consumers. The LSEôs are assumed to aggregate individual end-use consumer demands into óload blocksô for bulk buying at the wholesale level. Generators are assumed to produce and sell electrical power in bulk at the wholesale level.

2.1 Transmission Grid Characteristics.

The following assumptions were made in developing the ANEMMarket transmission grid. The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network with $N \geq 1$ branches and $K \geq 2$ nodes. The transmission grid is assumed to be óconnectedô to the extent that it has no isolated components: each pair of nodes *k* and *m* is connected by a linked branch path consisting of one or more branches.[6] We do not assume complete connectivity, however, implying that node pairs are not necessarily connected directly to each other through a single branch.

In common with the design features outlined in Sun and Tesfatsion (2007a, p. 5), we make the following additional assumptions:

- The reactance on each branch is assumed to be a total branch reactance, and not a per mile reactance;[7]

[5] It should be noted that óLocational Marginal Pricingô is the pricing of electrical power according to the location of its withdrawal from, or injection into, a transmission grid. The locational marginal price (LMP) at any particular node can be considered the least cost of meeting demand at that node for an additional unit [megawatt (MW)] of power.

[6] If two nodes are directly connected to each other, it is assumed to be at most by one branch thereby ruling out explicit consideration of branch groups.

[7] This means that the branch length is already taken into account.

- All transformer phase angle shifts are assumed to be 0;
- All transformer tap ratios are assumed to be 1;
- All line-charging capacitances are assumed to be 0; and
- Temperature is assumed to remain constant over time ï permitting us to use a constant value for the reactance on each branch.

Base apparent power S_0 is assumed to be measured in three-phase MVAôs, and base voltage V_0 in line-to-line KVôs. These quantities are used to derive per unit normalisations in the DC OPF solution and also to facilitate conversion between SI and PU unit conventions as required. Real power must be balanced across the entire grid, meaning that aggregate real power withdrawal plus aggregate transmission losses must equal aggregate real power injection.

The key transmission data required for the transmission grid within the model relate to an assumed base voltage value (in KVôs) and base apparent power (in MVAôs)[8], branch connection and direction of flow information as well as the maximum thermal rating of each transmission line (in MWôs), together with an estimate of its (SI) reactance value (in ohms).

In accordance with the WPMP power design, the transmission grid has a commercial network consisting of ópricing locationsô for the purchase and sale of electricity power.[9] We assume that the set of pricing locations coincides with the set of transmission grid nodes.

2.1 The LSE Agents.

The LSE agents purchase bulk power in the wholesale power market each day in order to service customer demand (load) in a downstream retail market ï thus, they link the wholesale power market and the downstream retail market. LSEôs purchase power only from generators because they are assumed to not engage in production or sale activities in the wholesale power market. In principle, at each node there can be zero, one or more LSEôs.

For simplicity, it is assumed that downstream retail demands serviced by the LSEôs exhibit negligible price sensitivity and hence reduces to daily supplied load profiles. In addition, LSEôs are modelled as passive entities who submit daily load profiles (i.e. demand bids) to the ISO without strategic considerations (Sun and Tesfatsion (2007b, p. 11)). The revenue (and profit) received by LSEôs for servicing these load obligations are regulated to be a simple ódollar mark-upô based retail tariff that is independent of the wholesale cost level. Therefore, in the current set-up, LSEôs have no incentive to submit price-sensitive demand bids into the market.[10] Therefore, we

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[8] Base apparent power is set to 100 MVA, an internationally recognized value for this variable. Thermal ratings of transmission lines and SI reactance values were supplied by the QLD, NSW and TAS transmission companies Powerlink, Transgrid, and Transend. For VIC and SA, the authors used values based on the average óPU-valuesô associated with comparable branches in the three above states.

[9] A pricing location is a location at which market transactions are settled using publicly available LMPôs.

[10] For example, in Queensland, the state government regulates retail tariffs that are payable by most residential customers. Prior to July 2009, this amount equated to 14.4c/KWh (excl GST) which, in turn, translated into a retail tariff of $144/MWh.

assume that just prior to the beginning of each day D each LSE submits a daily load profile to the ISO for day D, and this daily load profile represents the real power demand (in MWôs) that the LSE has to service in its downstream retail market for each of the 24 successive hours.[11]

The estimates of real power flow and injection/take-off at pre-specified transmission grid nodes as well as spot prices at each node obtained from the DC OPF solution constitute óquantityô and ópriceô variables that are used to calculate respective generator and LSE revenues and costs associated with wholesale market (spot market) transactions and assessments of the need for hedge cover.

2.3. Generator Agents.

The ANEMMarket agents are electric power generating units, and each generator is configured with a production technology. In principle, zero, one or more generators can be located at each node in the transmission grid. It is assumed further that generators can sell power only to LSEôs and not to each other.

With regard to production technology, it is assumed that generators have variable and fixed costs of production, but do not incur other costs such as no-load, start-up, or shutdown costs. At this stage, we also assume that they do not face ramping constraints (Sun and Tesfatsion (2007b, p. 11)).

For each generator, technology attributes are assumed, and these attributes refer to the feasible production interval[12], total cost function, total variable cost function, fixed costs [pro-rated to a $(\$/h)$ basis] and a marginal cost function. Variable costs of each generator are modelled as a quadratic function of hourly real energy produced by each generator on an óenergy generatedô basis. The marginal cost function is calculated as the partial derivative of the quadratic variable cost function with respect to hourly energy produced, yielding a marginal cost function that is linear in hourly real energy production of each generator (Sun and Tesfatsion (2007b, p. 12)).[13]

The variable cost concept underpinning each generatorôs variable cost as well as the system-wide variable cost incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. The fuel, VO&M and carbon emissions/cost parameterisation of the variable cost (and marginal cost) functions is derived from data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation units.

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[11] The regional load data for QLD and NSW was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by AEMO for the óQLD1ô and óNSW1ô markets. Time series data relating to the AEMO óQLD1ô and óNSW1ô data can be found at: http://www.aemo.com.au/data/price_demand.html. For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand contained in the annual planning reports published by the respective transmission companies Transend (TAS), Vencorp (VIC) and ElectraNet (SA). These regional load shares were then multiplied by the óTAS1ô, óVIC1ô and óSA1ô state load time series published by AEMO in order to derive the regional load profiles for TAS, VIC and SA that are used in the model.

[12] The feasible production interval refers to the minimum and maximum thermal (MW) rating of each generator. This is defined in terms of both óenergy sent outô and óenergy generatedô concepts.

[13] The intercept of the marginal cost function is the linear coefficient of the variable cost function and its slope is given by the quadratic coefficient of the variable cost function.

Over the medium to long term, generators need to cover fixed operating costs while also making contributions to debt servicing and producing acceptable returns to shareholders. We determine the debt and equity charge component of fixed costs as an amortised costs derived from an overnight capital cost expressed as a per kilowatt (kW) capacity charge across some period of time, typically a year, in order to count these fixed costs against the generator‟s installed capacity. The amortising formula used is conventional with the cost of debt and return to equity being combined in terms of a discount rate termed the Weighted Average Cost of Capital (WACC). As such, the debt and equity charges are assumed to be amortised over the assumed lifespan of the generation asset at a discount rate given by the WACC value that is also assumed for purposes of analysis (see Stoft (2002)). The amortising formula will produce a dollar per annum figure that represents the debt and equity charges which must be met and which, for modelling purpose, are then pro-rated to a $(\$/h)$ value.

The second component is Fixed Operation and Maintenance (FO&M) charges which are assumed to be some per annum dollar amount that will grow over time at the inflation rate assumed for cost components (i.e. at full CPI). This per annum value is also pro-rated to a $(\$/h)$ basis. Thus, the total fixed cost for each generator is defined as the sum of the FO&M and debt and equity charge and is defined on a $(\$/h)$ basis.

2.4 Passive Hedging

Both theory and observation suggest that financial settlements based on „Gross Pool‟ spot market operations expose market participants to the possibility of extreme volatility in spot prices encompassing price spike behaviour (typically of short duration) on the one hand and sustained periods of low spot prices on the other. These impacts can pose significant danger to the bottom line of both LSE‟s and generators respectively, requiring both types of agents to have long hedge cover positions in order to protect their long term financial viability.

A key decision for both sets off agents is when to activate long cover in order to protect their bottom lines from the consequences of consistently high (low) spot prices – a key determinant of „excessively‟ high costs („excessively‟ low revenues) faced by LSE‟s and generators that could potentially pose problems for their continued market solvency. The protection adopted in the model is in the form of a „collar‟ instrument between LSE‟s and generators which is activated whenever spot prices rise above a ceiling price (for LSE‟s) or falls below a price floor (for generators) subsequently inducing the activation of long cover for the threatened agent.[14]

It is assumed that both LSE‟s and generators have to pay a (small) fee (per MWh of energy demanded or supplied) for this long cover (irrespective of whether long cover is actually activated). This payment constitutes a partial profit transfer back to generators (LSE‟s) on the part of LSE‟s (generators) seeking long cover. Thus, the small fee acts like a conventional premium payment in options theory.

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[14] If the price floor applicable to generators is set equal to the generators long run marginal (i.e. „levelised‟) cost, then generator long run revenue recovery can be implemented through the implementation of hedge cover.

If the spot price is greater than the price floor applicable to generator long cover and below the price ceiling applicable for LSE long cover, than no long cover is activated by either generators or LSEôs although the fee payable for the long cover is still paid by both types of agents.

2.5 DC OPF Solution

The standard AC Optimal Power Flow (OPF) problem involves the minimization of total variable generation costs subject to nonlinear balance, branch flow, and production constraints for real and reactive power. In practice, AC OPF problems are typically approximated by a more tractable DC OPF problem that focuses exclusively on real power constraints in linearized form.[15]

The standard DC OPF problem in per unit *(pu)* form can be represented as a *strictly convex quadratic programming (SCQP) problem*, that is, as the minimization of a positive definite quadratic form subject to linear constraints. The solution of this standard DC OPF problem as a SCQP problem directly provides solution values for real power injections. However, solution values for locational marginal prices (LMPôs), voltage angles, and real power branch flows have to be recovered indirectly by additional manipulations of solution values (Tesfatsion and Sun (2007a, Sections 3.2)).

Tesfatsion and Sun (2007a, Sections 3.3) demonstrate that the standard DC OPF problem can be augmented, while still retaining a SCQP form, so that solution values for LMPôs, voltage angles, and voltage angle differences can be directly recovered along with solution values for real power injections and branch flows. However, in its standard form, voltage angle substitution eliminates the nodal balance constraints and hence the ability to directly generate solution values for LMPôs, which are the shadow prices for the nodal balance constraints. Therefore, the óaugmentationô requires an implementation of an alternative version of the standard DC OPF problem that makes use of Lagrangian augmentation. This augmented DC OPF problem can directly generate solution values for LMPôs, voltage angles, and voltage angle differences as well as real power injections and branch flows while retaining the numerically desirable SCQP form, [see Tesfatsion and Sun (2007a, Sections 3.4)].

The augmented SCQP problem can be solved using QuadProgJ, a SCQP solver developed by Sun and Tesfatsion [see Sun and Tesfatsion (2007a, Section 6)]. The program platform QuadProgJ implements the dual active-set SCQP algorithm developed by Goldfarb and Idnani (1983) and is programmed in Java. The advantage of the SCQP formulation is its highly desirable properties from the standpoint of stable numerical solution properties. [16]

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[15] Sun and Tesfatsion (2007a, pp. 40-42) formally demonstrate how the conventional AC OPF power flow equations can be derived from Ohmôs law and how the DC OPF problem can be formally derived from the AC OPF power flow equations, [see Sun and Tesfatsion (2007a, pp. 8-10)].

[16] The SCQP algorithm has two potential limitations. The first is the requirement that the QP objective function be a strictly convex function. The second is that the JAVA code implementing the algorithm does not incorporate sparse matrix techniques, and as a consequence, is not designed for large-scale problems for which speed and efficiency of computation become critical limiting factors.

The augmented SCQP problem involves the minimization of a positive definite quadratic form subject to a set of linear constraints in the form of equality and inequality constraints. The objective functions involve quadratic and linear variable cost coefficients and bus admittance coefficients. The solution values are the real power injections and branch flows associated with the energy production levels (on an 'energy sent out' basis) for each generator and voltage angles for each node.[17]

The equality constraint is a nodal balance condition which requires that at each node, power take-off (by LSE's located at that node) equals power injection (by generators located at that node) and net power transfers from other nodes connected to the node in question via 'connected' transmission grid branches. The imposition of this constraint across all nodes in the transmission grid will ensure that real power will be balanced across the entire grid by ensuring that aggregate real power withdrawal plus aggregate transmission losses equal aggregate real power injection. Furthermore, on a node by node basis, the shadow price associated with this constraint give the LMP (i.e. regional or nodal wholesale spot price) associated with that node.

The inequality constraints ensure that real power transfers on connected transmission branches remain within permitted thermal limits and the power produced by each generator (on an 'energy sent out' basis) remains within permitted lower and upper thermal limits. The algorithm has also been extended to include an aggregate carbon emissions constraint. This is an inequality constraint requiring that aggregate (i.e. system wide) carbon emissions remain below some pre-specified target value. If this constraint is violated, it will typically produce a contemporaneous price spike that represents the cost of the emission constraint violation.

3. An illustrative application of the ANEMMarket Model

To demonstrate the type of analysis that can undertaken by the ANEMMarket model, we present some preliminary simulation results of the impacts of several carbon price scenarios for regional load profiles on 23/1/2007, which was a day that contained a number of hourly peak demand periods for the Sydney node.

The transmission grid used involved combining the existing QLD, NSW, VIC, SA and TAS modules - see Figures 1-5. The state module linking was via the following Interconnectors: QNI and Directlink Interconnectors linking QLD and NSW; Murray-Dederang Interconnector linking NSW and VIC; Heywood and MurrayLink Interconnectors linking VIC and SA; and the Basslink Interconnector linking VIC and TAS. It should also be noted that the HVDC Interconnectors Directlink, Murraylink and Basslink are modelled as 'quasi AC' links – that is, power flows are determined by assumed reactance and thermal rating values for each of the above-mentioned HVDC branches.

The solution algorithm that was utilised in the simulations involved applying the 'competitive equilibrium' solution. This meant that all generators submitted their true marginal cost coefficients and no strategic bidding was possible. This type of scenario allowed assessment of the true cost of generation and dispatch by ruling our cost inflation over their true marginal costs associated with the exploitation of market

[17] One voltage angle is eliminated by setting its value equal to zero. This is a normalisation condition so solution values are actually determined for voltage angles of 'K-1' nodes.

power associated with strategic bidding. Because the dispatch algorithm employed marginal cost pricing, the competitive equilibrium solution would lead to the discovery of the lowest overall configuration of Locational Marginal Pricesô (LMP) consistent with the nodal location of generators and thermal and other constraints on the transmission network connecting the regional nodes. As such, this strategy permitted an investigation of the true cost and ómarket operatorô determined dispatch response of different fuel based generation technologies in response to how their true marginal costs changed with carbon price increases.

In this section, it is assumed that all thermal generators are available to supply power during the day. As such, this modelling scenario is an óas ifô scenario. In particular, we did not try to emulate actual generator bidding patterns for the particular day in question. Our objective, instead, is to investigate how the true cost of power supply changed for the various carbon price scenarios considered, and how the resulting changes in the relative cost of supply influenced dispatch patterns, transmission congestion, regional prices and carbon emission levels when compared to a óBusiness-As-Usualô (BAU) scenario involving the absence of a carbon price signal.

While all thermal generators were assumed to be available to supply power, certain assumptions were imposed in relation to the availability of hydro generation units. In particular, the following hydro generation units were assumed to be available to supply power during the following hourly time intervals:

Far North QLD (all hydro generation units): 07:00 ï 21:00;
Wivenhoe (units 1 and 2)[18]: 09:00 ï 18:00;
Shaolhaven Scheme (Kangaroo Valley unit 1): 07:00 ï 12:00 and 17:00 ï 20:00;
Shaolhaven Scheme (Bendeela unit 1): 09:00 ï 11:00 and 17:00 ï 19:00;
Snowy Mountains Hydro Scheme:

- Blowering: 09:00 ï 12:00 and 16:00 ï 19:00;
- Tumut 1 (unit 1) and Tumut 2 (unit 1): 07:00 ï 21:00;
- Tumut 3 (unit 1): 07:00 ï 21:00;
- Tumut 3 (unit 2): 10:00 ï 19:00;
- Guthega (unit 1): 10:00 ï 19:00;
- Murray 1 (unit 1 and unit 2): 07:00 ï 21:00;
- Murray 1 (unit 3): 11:00 ï 17:00;
- Murray 2 (unit 1): 07:00 ï 21:00; and
- Murray 2 (unit 2): 10:00 ï 19:00.

Combined Southern Hydro/Victorian Fleet:

- Hume (unit 1): 11:00 ï 17:00;
- Dartmouth: 07:00 ï 11:00 and 17:00 ï 21:00;
- McKay Creek (unit 1): 11:00 ï 17:00;

[18] For pump-storage hydro units such as Wivenhoe and the Shoalhaven Scheme units, the pump mode was activated in the model by setting up a pseudo LSE located at the Morton North and Wollongong nodes, respectively. In the case of Wivenhoe, each unit can generate power for up to 10 hours and then has to implement pump action for 14 hours in a 24 hour period. This was implemented by having each hydro unit act as a pseudo LSE and demand (i.e. purchase) 240MW of power per hour over a fourteen hour period in the 24 hour period. The combined load requirements for pump actions of all Wivenhoe and Shoalhaven hydro units were combined into a single load block for each respective pseudo LSE. For the Shoalhaven scheme, the pump action requirements matched the generation patterns. In both cases, pump actions occur in off-peak periods, e.g. at night, when the price (cost to hydro units) of electricity should be lower.

- West Kiewa (unit 1): 11:00 ï 17:00;
- Clover (unit 1): 11:00 ï 17:00; and
- Eildon (unit 1): 07:00 ï 11:00 and 17:00 ï 21:00.

The following Tasmanian hydro generation units are assumed to offer power over the complete 24 hour period: Rowallan, Fisher, Lemonthyme, Wilmot, Cethana, John Butters, Tribute, Reece (unit 1), Trevallyn (units 1-2), Poatina (units 1-5), Liapootah (unit 1), Wayatinah (unit 1), Catagunya (unit 1), Repulse, Butlers Gorge, Lake Echo, Tungatinah (units 1-3), Tarraleah (units 1-3), Meadowbank and Gordon (units 1-3). Additionally, the following hydro generation units are assumed to be available to supply power for the following periods of time:

- Devils Gate: 07:00 ï 21:00;
- Paloona: 06:00 ï 21:00;
- Mackintosh: 07:00 ï 21:00;
- Bastyan: 07:00 ï 21:00;
- Reece (unit 2): 07:00 ï 21:00;
- Trevallyn (unit 3): 07:00 ï 21:00;
- Liapootah (unit 2): 01:00 ï 21:00;
- Wayatinah (unit 2): 01:00 ï 19:00;
- Catagunya (unit 2): 07:00 ï 11:00 and 17:00 ï 20:00;
- Cluny: 08:00 ï 20:00;
- Tungatinah (unit 4): 10:00 ï 20:00;
- Tarraleah (unit 4): 06:00 ï 22:00; and
- Tarraleah (unit 5): 07:00 ï 12:00 and 16:00 ï 21:00.

The dispatch of the thermal plant was optimised around the above assumed availability patterns for the specified hydro generation units. For modelling purposes, all other hydro generation units were assumed to not be available to supply power. It should be noted that the availability of ómainlandô hydro generation plant to supply power effectively ensures that they would be dispatched at their full thermal (MW) rating because their marginal costs are low in comparison to other competing thermal plant and, importantly, do not change as carbon prices increase. Moreover, because we assumed a social (environmental) water cost of $1/ML in deriving the marginal cost of hydro plant, hydro plant that require less water to produce a MW of power will be less costly than generators that have to use more water to produce a MW of power. This social cost consideration will be especially relevant to the dispatch of hydro plant in Tasmania with óleast costô hydro plant typically being those units which have the highest head such as Poatina, for example.

In many respects, hydro plant exhibits many of the characteristics of peak plant including very fast start-up capabilities. However, notwithstanding this consideration, many of the Tasmanian hydro units, in particular, are expected to meet baseload or intermediate production duties. In particular, Rowallan, Butlers Gorge, Meadowbank, Lake Echo, Tarraleah, Poatina and Gordon are typically expected to operate as baseload generation plant. Furthermore, Trevallyn, Tungatinah, and most of the generators located at the Sheffield, Farrell and Liapootah nodes are expected to meet intermediate duties and possibly switch to baseload production duties if required.

In general, two fuel substitution effects were evident in the scenarios considered in response to increases in the carbon price. The first was a general substitution of gas fired generation for coal fired generation as the carbon price was increased. The second substitution was the substitution of newer coal fired plant for older coal fired plant. This reflected the fact that the newer plant had better thermal and lower emission intensities than older coal plant. These broad trends can be discerned from inspection of the following tables. These tables display the average dispatch levels as a percentage of total portfolio capacity (in terms of energy generated) over the 24 hour period for various carbon price scenarios considered.

Table 1a. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of QLD and NSW Gas Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007							
SCENARIO	Townsville	Barcaldine	Roma	Braemar	Swanbank E	Smithfield	Tallawara
$0/tC02 BAU	0.00	0.00	2.19	24.32	52.92	25.67	27.76
$10/tC02	0.00	0.00	2.19	24.33	52.94	26.00	30.01
$20/tC02	0.00	0.00	2.19	24.33	57.30	26.12	39.98
$30/tC02	2.70	0.00	2.19	24.33	79.32	40.82	77.53
$50/tC02	100.00	0.00	2.19	60.27	100.00	100.00	100.00
$70/tC02	100.00	100.00	1.56	100.00	100.00	100.00	100.00
$100/tC02	100.00	100.00	0.00	100.00	100.00	100.00	100.00

Table 1b. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of NSW and VIC Gas Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007							
SCENARIO	Uranquinty	Valley Power	Jeeralang A	Jeeralang B	Bairnsdale	Somerton	Newport
$0/tC02 BAU	0.00	0.00	0.00	0.00	19.40	19.26	7.63
$10/tC02	0.00	0.00	0.00	0.00	19.41	19.78	7.40
$20/tC02	0.00	0.00	0.00	0.00	22.87	21.11	7.81
$30/tC02	0.00	0.00	0.00	0.00	22.87	25.00	9.71
$50/tC02	0.05	0.00	39.0	31.49	100.00	94.65	18.31
$70/tC02	26.02	0.00	99.57	96.08	100.00	100.00	55.77
$100/tC02	68.01	34.45	100.00	100.00	100.00	100.00	88.31

Table 1c. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of VIC and SA Gas Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007							
SCENARIO	Laverton Nt	Ladbroke Gr	Pelican Pnt	Quarantine	New Osbourne	Torrens Is A	Torrens Is B
$0/tC02 BAU	1.95	60.77	46.58	12.87	43.61	0.00	5.51
$10/tC02	1.36	65.49	65.52	14.08	66.73	0.00	5.45
$20/tC02	1.04	46.68	70.74	15.79	71.50	0.00	5.79
$30/tC02	2.13	95.02	100.0	22.05	100.00	0.00	8.33
$50/tC02	4.77	100.00	100.00	44.24	100.00	0.00	14.74
$70/tC02	34.57	100.00	100.00	100.00	100.00	0.00	51.89
$100/tC02	81.65	100.00	100.00	100.00	100.00	38.92	96.06

Table 1d. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of SA and TAS Gas Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007					
SCENARIO	**Dry Ck**	**Mintaro**	**Hallett**	**Bell Bay**	**Bell Bay 3**
$0/tC02 BAU	0.00	0.00	0.00	0.00	0.00
$10/tC02	0.00	0.00	0.00	0.00	0.00
$20/tC02	0.00	0.00	0.00	0.00	0.00
$30/tC02	0.00	0.00	0.00	0.00	0.00
$50/tC02	0.00	0.00	0.00	18.03	0.00
$70/tC02	0.00	0.00	35.88	63.18	0.00
$100/tC02	0.00	0.00	100.00	68.59	0.00

Tables 1a-1d display the results for gas fired thermal portfolios. Inspection of these tables indicates that the dispatch patterns did not change much for carbon prices in the range of $0/tC02 to $20/tC02. The slightly larger percentages for Swanbank E, Ladbroke Grove, Pelican Point, and New Osborne reflects the fact that, in relative terms, both the ólandedô gas prices are cheaper and the thermal properties of these plants are better when compared to other competing gas plant.

In the carbon price range of $30/tC02 to $50/tC02, the relative cost of gas fired plant is approaching or has become less than the relative cost of most of the black coal fired plant fleet commissioned between 1965 and 1995. In QLD and NSW, this leads to the full dispatch of Townsville (Yabulu), Swanbank E, Smithfield and Tallawara gas portfolios and the Braemar portfolio to a less extent ï see Table 1a. The lower dispatch percentages for Braemar reflect the fact that it is located at the same node as Kogan Creek and Millmerran coal fired portfolios which are amongst the cheapest and most thermally and carbon efficient coal fired plant in Australia. In VIC and SA, the increased competitiveness of gas fired generation led to high levels or full dispatch of Bairnsdale, Somerton, Ladbroke Grove, Pelican Point and New Osborne reflecting the relatively cheaper cost of gas and better thermal properties of the plant when compared to other competing gas plant located in these states.

At a carbon price of $100/tC02, all gas portfolios apart from Uranquinty, Valley Power, Torrens Island A and Bell Bay are either fully dispatched or dispatched at a high percentage level of their total portfolio capacity.[19] The results for Uranquinty reflect the fact that it is located at the same node (Tumut) as a significant proportion of the Snowy Mountain hydro generation plant which is dispatched at very lower marginal cost which does not change as carbon prices are increased. Therefore, some of this hydro generation plant dispatch would be potentially displacing dispatch that might have emerged for Uranquinty as the price of carbon increased. The other results primarily reflect the fact that these gas plants face more expensive gas prices and/or are less thermally efficient than other competing gas plant.

[19] We have ignored Roma, Dry Creek, Mintaro and Bell Bay Three (Tamar Valley) which were either not dispatched or dispatched at very low levels in all carbon price scenarios considered.

The key result to emerge from the results cited in Table 1a-1d is that a carbon price in the range of $50/tC02 to $70/tC02 seems to be needed to induce significant substitution of gas fired generation for existing coal fired generation. This observation is further supported when consideration is taken into account of the must run minimum stable operating capacity required for many of these gas plants. As a broad rule of thumb, this could be regarded as being around 50% of total operating capacity. As such, only percentages in excess of 50% in Tables 1a-1d would constitute viable daily operating capacity rates for many of the gas plant listed in these tables.[20] Only Swanbank E, Tallawarra, Ladbroke Grove, Pelican Point and New Osborne achieve this effective minimum operating capacity percentage rate at a carbon price of $30/tC02. It is also evident from inspection of Tables 1a-1d that higher carbon prices in the range of $50/tC02-$70/tC02 seem to be required to achieve viable minimum stable operating percentage rates for most of the gas fleet.

The dispatch results for black coal fired plant commissioned between 1965 and 1976 (in QLD and NSW) are displayed in Table 2. Inspection of this table generally demonstrates the substitution of other generation sources for the óldô coal fired fleet where alternative sources of supply exist within the nodal structure of the transmission grid. First, it should be noted that the Collinsville fleet is never dispatched ï the cheaper and more carbon efficient hydro generation plant in the Far North Queensland Node and well as ónewerô coal fleet in the Central West Queensland Node effectively displace it as a viable source of supply. There is a slight reduction in the percentage dispatch of the Gladstone Fleet but its nodal position in servicing the sizeable industrial load associated with the Gladstone regional area and the absence of alternative competing generators at this node ensures its continued dispatch at significant levels. The same nodal positioning argument also applies to Wallerawang especially given the reduction in output from Liddle and Munmorah (at higher carbon price levels).

The other coal fired generation portfolios listed in Table 2 display significant reduction in their percentage dispatch figures. This would principally reflect substitution of gas for these coal fired generators as well as substitution from newer cheaper coal fired plant. For Swanbank B, the key driver would be displacement by Swanbank E as carbon prices make Swanbank E more competitive relative to the coal fired Swanbank B portfolio. For the Liddle and Munmorah portfolios, they key sources of displacement are substitution of cheaper and more thermally efficient coal fired dispatch (particularly from Bayswater) plus the export of cheaper power sourced from the South West Queensland node as well as the increased dispatch of the Smithfield and Tallawara gas portfolios (as the carbon price is increased).

[20] Some care needs to be exercised with the interpretation of the capacity percentages which are taken as the average hourly dispatch level over the complete 24 hour period. This follows because most gas plant would not be expected to run over a 24 hour period. Thus, if the averaging was performed only during daylight hours, for example, these percentages might increase. Fortunately, the ócheaperô gas plant tends to be plant that is capable of running for 24 hours to meet intermediate production duties ï these plant include Townsville, Braemar, Swanbank E, Smithfield, Tallawarra, Bairndales, Somerton, Ladbroke Grove, Pelican Point and New Osborne.

Table 2. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of 'Old Vintage' Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007						
SCENARIO	Collinsville	Gladstone	Swanbank B	Liddle	Munmorah	Wallerawang
$0/tC02 BAU	0.00	75.20	62.50	78.50	64.25	44.34
$10/tC02	0.00	75.19	62.50	55.96	62.50	47.02
$20/tC02	0.00	75.14	59.12	42.98	41.75	56.24
$30/tC02	0.00	71.73	54.72	29.39	31.29	60.21
$50/tC02	0.00	68.00	31.65	8.92	69.28	77.66
$70/tC02	0.00	64.12	31.65	1.70	64.68	77.66
$100/tC02	0.00	64.19	31.66	2.45	44.60	76.36

In Table 3, the average daily percentage dispatch patterns for black coal fired plant commissioned in QLD and NSW between 1977 and 1995 are displayed. The only portfolio displaying a significant reduction in average dispatch levels is the Callide B portfolio which would reflect displacement by the Townsville gas portfolio for carbon prices in excess of $30/tC02.[21] The contribution of the Bayswater portfolio increases as it displaces the older, less thermally and carbon efficient coal fired Liddle portfolio.

Table 3. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of 'Medium Vintage' Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007							
SCENARIO	**Stanwell**	**Callide B**	**Tarong**	**Bayswater**	**Eraring**	**Vales Point**	**Mt Piper**
$0/tC02 BAU	98.96	84.97	100.00	59.78	87.78	100.00	70.24
$10/tC02	100.00	82.91	100.00	78.91	83.79	100.00	80.82
$20/tC02	100.00	83.18	100.00	88.05	82.32	99.98	89.96
$30/tC02	100.00	83.16	100.00	95.46	91.84	100.00	100.00
$50/tC02	100.00	66.48	100.00	99.87	95.40	100.00	100.00
$70/tC02	100.00	57.61	100.00	99.87	95.88	100.00	100.00
$100/tC02	100.00	58.00	100.00	99.85	95.92	100.00	100.00

In Table 4, the average daily percentage dispatch patterns for black coal fired plant commissioned after 1995 in QLD and NSW are displayed. The only portfolio displaying a significant reduction in average daily dispatch is the Redbank portfolio. This displacement reflects the high carbon emission intensity of the tailing (i.e. coal waste) fuel source which induces it to be totally displaced for carbon prices of $20/tC02 or higher. This would reflect partial displacement by cheaper power supplied from the South West Queensland node and cheaper power being supplied from the more carbon efficient Bayswater coal fired generators. All other generators are dispatched fully reflecting their superior thermal, fuel cost and emission intensities factors when compared with other existing coal fired plant, even in the presence of significantly rising carbon prices. Finally, it is interesting to note that all of the newer,

[21] The fuel cost and emissions intensity of Callide B is slightly higher and thermal efficiency slightly lower than the corresponding results for Stanwell which is the key reason why the Callide B Portfolio is both dispatched less intensively and displaced more extensively than the Stanwell Portfolio.

cheapest, most thermally and carbon efficient black coal plant are located in Queensland.

Table 4. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of 'Latest Vintage' Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007					
SCENARIO	**Callide C**	**Tarong North**	**Kogan CK**	**Millmerran**	**Redbank**
$0/tC02 BAU	100.00	100.00	100.00	100.00	100.00
$10/tC02	100.00	100.00	100.00	100.00	20.83
$20/tC02	100.00	100.00	100.00	100.00	0.00
$30/tC02	100.00	100.00	100.00	100.00	0.00
$50/tC02	100.00	100.00	100.00	100.00	0.00
$70/tC02	100.00	100.00	100.00	100.00	0.00
$100/tC02	100.00	100.00	100.00	100.00	0.00

The dispatch results for the brown coal fired generators commissioned in VIC are displayed in Table 5. Inspection of this table generally demonstrates the substitution of other generation sources for the Victorian brown coal fired generation fleet in an environment of rising carbon prices. First, it should be noted that the only portfolio that remains relatively intact is the Loy Yang A portfolio at a carbon price of $100/tC02. This reflects the ǒfavourableô price of coal (when compared particularly to Loy Yang B, Energy Brix and Anglesea), thermal efficiency properties and emission intensity factor when compared, more generally, with the other competing brown coal portfolios located in Victoria. Hazelwood has the worst thermal and emission intensity factors, followed by Yallourn with these factors principally producing the dispatch patterns observed in Table 5 for these portfolios. The dispatch patterns associated with Energy Brix is primarily influenced by the high relative cost of brown coal confronting this particular portfolio.

Overall, the key outcome to emerge from the results cited in Table 5 is that carbon prices in the range of $30/tC02 to $50/tC02 seems to be needed to begin producing significant carbon price induced reductions in the levels of power produced by brown coal fired plant in Victoria with the portfolios most affected initially being Energy Brix, Hazelwood and Yallourn. Carbon prices around $100/tC02 seem to be needed to produce significant further reductions in the output of brown coal fired generation, notably affecting Loy Yang B and Anglesea. As mentioned above, at a carbon price of $100/tC02, the output of the Loy Yang A portfolio appears to remains intact in relative terms.

Table 5. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of Victorian Brown Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007						
SCENARIO	Loy Yang A	Loy Yang B	Energy Brix	Hazelwood	Yallourn	Anglesea
$0/tC02 BAU	100.00	100.00	100.00	100.00	100.00	100.00
$10/tC02	100.00	100.00	100.00	100.00	100.00	100.00
$20/tC02	100.00	100.00	64.87	100.00	100.00	100.00
$30/tC02	100.00	100.00	25.02	68.23	100.00	100.00

$50/tC02	100.00	100.00	0.00	17.55	67.52	100.00
$70/tC02	100.00	79.71	0.00	0.00	16.62	100.00
$100/tC02	88.99	23.80	0.00	0.00	8.46	36.26

Table 6 displays the results for black coal plant in SA. Inspection of this table indicates that the dispatch patterns for the Playford B portfolio decline as the carbon price increases with total displacement arising for carbon prices greater than or equal to $50/tC02. The results for the Northern portfolio reflect its better thermal and emission intensity factors when compared to the Playford B portfolio with carbon prices around $100/tC02 being required to produce the total displacement of this portfolio. These results qualitatively mirror the results cited in Table 2 in relation to the óolder vintageô black coal fired plant commissioned between 1965 and 1976 in QLD and NSW.

Applying the arguments used in Tables 1a-1d in relation to minimum stable operating capacity, for coal fired plant, the corresponding rule of thumb for viable operating capacity is generally thought to be 40% of total capacity (for black coal plant) and 60% of total capacity (for brown coal plant). As such, the percentages listed in Tables 2 to 6 that are below 40% or 60% for black and brown coal plant respectively indicates ónon-viableô average operating capacities. This consideration is even more prevalent in the case of coal fired plant because of the significant órun-upô time needed to go from ócoldô start-up to a position where the coal fired power station can actually begin to supply power to the grid. Therefore, unlike the case with gas fired generation plant, frequent óstop-startô behaviour is not an option for these types of plant.

Table 6. Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of SA Black Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007		
SCENARIO	Playford B	Northern
$0/tC02 BAU	91.05	100.00
$10/tC02	32.49	100.00
$20/tC02	25.52	100.00
$30/tC02	10.53	64.29
$50/tC02	0.00	90.76
$70/tC02	0.00	62.51
$100/tC02	0.00	0.00

Examination of Tables 2-6 indicate that Swanbank B has non-viable average daily operating capacity percentages for carbon prices higher than $30 (but perhaps closer to $50) , Liddle (higher than $20), Redbank (greater than or equal to $10), Loy Yang B (greater than $70), Energy Brix (greater than $20), Hazelwood (greater than $30), Yallourn (greater than $50), Anglesea (greater than $70), Playford B (greater than or equal to $10) and Northern (greater than $70). Munmorah poses an interesting case. The results for Munmorah fluctuate considerably with percentages being in the ónon-viableô range for carbon prices in the range $20-$50 but become viable once again for carbon prices greater than $50 although trending, once again, towards the non-viable range for a carbon price of $100/tC02.

Carbon emissions reduction from the "Business-As-Usual (BAU)" (i.e. no carbon price) scenario reflects the dispatch patterns observed above. The observed emission reductions are driven by the substitution of gas for coal fired plant and the substitution of newer coal plant with lower cost and emission intensities for older coal fired plant with higher cost and emission intensities.

Table 7. Carbon Emission Levels and Percentage Reductions from 'BAU' Associated with Various Carbon Price Scenarios

SCENARIO	Carbon Emissions (tC02)	% Change from BAU
$0/tC02 BAU	564106.9	
$10/tC02	558841.6	-0.93
$20/tC02	555490.7	-1.53
$30/tC02	538445.4	-4.55
$50/tC02	509108.4	-9.75
$70/tC02	482428.3	-14.48
$100/tC02	463985.0	-17.75

The results cited in Table 7 shows both the level of carbon emissions and percentage reduction from the "BAU" levels associated with the various carbon price scenarios. It is clear that the increase in the carbon price to a level of $100/tC02 has effected a reduction in aggregate (i.e. system wide) carbon emission levels from the BAU level of 17.75 percent. Apart from the dispatch of more hydro generation plant from the Snowy Mountain nodes of Tumut and Murray in NSW, it is difficult to see how carbon emissions could be reduced much further with the existing fleet of generators. The cheapest, most carbon and thermally efficient coal fired plant are being fully dispatched together with most of the gas turbine fleet apart from the Uranquinty, Valley Power, Torrens Island A and Bell Bay portfolios. The most expensive and carbon emission intensive coal plant's dispatch has been largely displaced so additional capacity capable of eating into the aggregate carbon footprint seems very limited, apart from the remaining hydro generation units mentioned above.[22] Moreover, the remaining peak plant that has not been dispatched is the diesel based fleet which face marginal costs in the order of $300/MWh and do not have a large aggregate MW capacity. They also have higher carbon emission intensities than natural gas fired generation plant that has been largely dispatched.

Therefore, if the above pattern of emission reduction is indicative given the existing structure and nodal location of thermal plant and binding constraints on hydro generation, then in order to obtain further deep emission cuts, two possible and interrelated approaches would seem to be necessary. On the supply side, significant investment in additional capacity based on proven low emission intensity technologies

[22] Complicating the dispatch of hydro generation units in the Snowy Mountains Hydro scheme is the fact that water releases are determined as part of the management of irrigation releases into the Murray and Murrumbidgee River systems.

capable of meeting baseload and intermediate production duties such as NGCC or OCGT technologies would be needed, especially if renewable supply side proposals based on clean coal, geothermal, solar thermal and wind prove problematical. Second, demand side initiatives that focus on reducing the aggregate load that has to be serviced by generators will also reduce carbon emissions especially if the load reduction is fulfilled by renewable technologies. Such options might relate to the use of solar PV technologies, thermal heating and air-conditioning, smart metering which manages and reduces load during peak demand periods as well as improved energy efficiency associated with the uptake of improved construction standards and techniques.

Plots of the optimal system variable costs (defined in terms of $000's/h) determined from the DC OPF algorithm used to determine dispatch and regional prices is shown in Figure 6. It is apparent from inspection of this figure that the variable cost profiles shift upward with increases in the carbon price. The shape of each profile also indicates that more costly generation plant has to be dispatched to meet peak daily demand. For lower carbon prices, this would be associated with the more intense dispatch of more expensive gas fired generation. For higher carbon prices, this would reflect the continued need to dispatch coal fired generation to service load demand in an environment where their relatively higher emission intensity factors (when compared with gas plant) translate into higher relative variable carbon costs.

The upward shift in the system variable cost functions documented in Figure 6 will translate into upward shifts in the average wholesale price of electricity. This can be discerned by inspecting Figure 7. It is evident from inspection that the average price profile shifts upwards as the carbon price (and system variable costs) increase. For low carbon prices (in the range $0/tC02-$30/tC02) the shape of the average price profile remains the same and the magnitude of the upward shift remains approximately the same. This reflects the fact that the carbon price has been increased in increments of $10/tC02. The other noticeable observation is that the small plateau effect associated with hours 13:00-18:00 at lower carbon prices largely disappears for higher carbon prices in the range $70/tC02 to $100/tC02. Thus, at higher carbon price levels, the daily variation seems to have been smoothed as stable dispatch patterns involving the employment of the most efficient coal plant and gas plant emerge.

Nodal based price variations within a state and between states is possible when branch congestion arises on one or more transmission lines. This is possible, in the current setting, if the introduction of a carbon price causes the dispatch patterns to change significantly from the "BAU" dispatch patterns. To investigate this issue, we present a brief profile of the transmission lines experiencing congestion for the "BAU" scenario and the "$100/tC02" carbon price scenario. This information is documented in Table 8 and Table 9 respectively, together with the various Interconnector (MW) flows between the various state modules. It should be noted that the positive MW values associated with QNI and Directlink indicate power transfers from Queensland to New South Wales. A positive value for the NSW-VIC (Murray-Dederang) Interconnector depicts power transfers from NSW to VIC. Similarly, positive values for the Heywood and Murraylink Interconnectors indicate power transfers from VIC to SA. Finally, a positive value for the Basslink Interconnector will depict power transfers from VIC to TAS.

It is apparent from inspection of Table 8 that for the óBAUô scenario, significant branch congestion occurs on the óCentral West QLD ï Tarongô (line 5), óLismore to Armidaleô (line 15), óBayswater to Sydneyô (line 20), óGeorge Town to Sheffieldô (line 60), óGeorge Town to Hadspenô (line 61), óHadspen to Palmerstonô (line 65), óWaddamana to Tarraleahô (line 68) branches and more episodically on the óLiddle to Newcastleô (line 19), óSydney to Mt Piperô (line 24), and óHazelwood to Greater Melbourne and Geelongô (line 43) branches. Furthermore, power transfers primarily from QLD to NSW on the QNI and Directlink Interconnectors, from TAS to VIC on the Basslink Interconnector and from VIC to SA on both the Heywood and Murraylink Interconnectors. The nature of the power flows on the óNSW-VICô (Murray-Dederang) Interconnector is more mixed with power flowing from VIC to NSW during off-peak periods (i.e. 01:00-07:00 and 19:00-24:00) and with power primarily flowing from NSW to VIC during the daily peak period (08:00ï18:00).

For the ó$100/tC02ô scenario, it is apparent from inspection of Table 9 that congestion continues on branch lines 5 and 15 although the extent of congestion on line 15 has diminished as power flow from QLD to NSW on Directlink has increased, thus reducing the need for power from the Liddle and Bayswater based generators in order to service load demand in northern regions of New South Wales. Congestion on branch line 20 has also diminished marginally possibly in response to the increased dispatch of gas fired Smithfield and Tallawara portfolios in servicing load demand associated with the Sydney node. There is also episodic evidence of some congestion on branch lines 16 (Armidale to Tamworth) and on line 35 (Tumut to Murray). As with the case of the BAU scenario, significant congestion also remains on the TAS transmission branches associated with lines 60, 61, 65 and line 68.

The nature of power transfers on the various Interconnectors has also changed in important respects from the óBAUô results cited in Table 8. Specifically, power flows unambiguously from QLD to NSW on both the QNI and Directlink Interconnectors. The source of generation underpinning these power flows largely originates from the South West Queensland node. Power also now flows unambiguously from NSW to VIC on the Murray-Dederang (NSW-VIC) Interconnector with this supply being sourced primarily from the various generators located at the Tumut and Murray nodes, including the increased dispatch of the Uranquinty gas portfolio. Power also flows from TAS to VIC on the Basslink Interconnector with the value of 594 MWôs representing the maximum permitted thermal limit for TAS to VIC power flows on Basslink. Thus, the Basslink Interconnector power transfers from TAS to VIC are congested for all hours of the particular day being considered, primarily capturing not only power sourced from hydro based units located at the Sheffield, Farrell and Hadspen nodes, but also the dispatch of the Bell Bay gas portfolio located at the George Town node. The other noticeable result is that power also now flows unambiguously from SA to VIC on both the Heywood and Murraylink interconnectors. This is a complete turn-around from the results associated with the óBAUô scenario that were cited in Table 8. Furthermore, the 220 MW values listed in both Tables 8 and 9 for Murraylink represent maximum thermal limits for power flows on this particular Interconnector. Thus, in both the óBAUô and ó$100/tC02ô carbon price scenarios listed in Tables 8 and 9 respectively, the Murraylink Interconnector is congested for considerable periods of time, although the actual *direction* of the power transfers differ fundamentally under these two particular scenarios. Thus, with the high carbon price induced displacement of much of the

Victorian brown coal generation, cheaper hydro and gas based generation sourced from NSW, SA, and TAS are being consistently exported into VIC.

In order to demonstrate the nature of regional (nodal) price variation produced by the branch congestion, we present graphs containing plots of the hourly average, minimum and maximum nodal prices for a selection of the carbon price scenarios. These plots are documented in Figures 8aï 8e, respectively.

These figures indicate that there is a substantial difference between the minimum and maximum nodal price for all selected carbon price scenarios considered. For the óBAUô scenario (Figure 8a), the maximum nodal prices during the peak demand period (10:00 to 20:00 hours) are consistently in excess of $100/MWh and goes as high as $180/MWh. Moreover, these maximum nodal prices do not necessarily relate to a single particular node ï for example, for the BAU scenario, different nodes including Riverlands (in SA) and Lismore (in NSW) set the maximum nodal price at different hours of the day.[23] The corresponding average price level is in a range between $25/MWh to $40/MWh. The corresponding minimum prices are in quite a narrow range encompassing a $3/MWh to $4.50MWh price band. These low prices are associated with some generation only nodes in Tasmania containing hydro generation units that have very low marginal costs. Furthermore, because the marginal costs of hydro generation will not change in an environment of increasing carbon prices, the minimum prices will remain the same for all the carbon price scenarios considered.

The pattern discerned above in relation to the óBAUô scenario continues for all other selected carbon price scenarios listed in Figures 8b to 8e. The main difference is an overall upward shift in the price series as the carbon price level is increased reflecting the upward shift in variable and marginal costs. The narrowing and increasing prominence of the plateau effects observed in Figures 8b to 8e around the hourly interval 17:00 to 18:00 hours and at 20:00 hours coincides with nodal prices at the Lismore node. This price behaviour primarily reflects the incremental increase in the dispatch of both Swanbank B and Liddle portfolios at these hours to meet the incrementally higher demand at this particular node. The price spike behaviour reflects incremental increase in marginal costs associated with increased dispatch of coal fired plant whose marginal costs are particularly susceptible to high carbon prices given the high carbon footprint of both plant when compared to other competing generation plant located at the South West QLD, Tarong and Bayswater nodes. It should also be noted, however, that these price fluctuations do not show up in the average price profiles outlined in these figures. As such, these price fluctuations are limited to the Lismore node at these particular hours and are not propagated to other neighbouring nodes.

4. Concluding Comments

Interesting as these preliminary simulation results are, they remain illustrative because, in reality, base load and intermediate coal and gas plant typically have a non-zero ómust runô MW capacity levels termed a óminimum stable operating level.ô These plants cannot be run below these specified MW capacity levels without

[23] In general, for carbon prices above $50/tC02, the Sydney node (i.e. node 19) also episodically sets the maximum price, together with the Riverlands and Lismore nodes.

endangering the long term productive and operational viability of the plant itself or violating statutory limitations relating to the production of pollutants and other toxic substances such as N02.

Furthermore, depending upon the time interval associated with each dispatch interval, care might also need to be exercised to ensure that each generatorôs ability to increase or decrease effective production levels do not violate thermally defined ramp-up and ramp-down limits. In particular, because of these ramp rate constraints, the effective upper or lower production limit within a given dispatch interval might be below the maximum (sent out) thermal MW rating of the unit or above the minimum (stable) operating MW capacity of the unit respectively. Moreover, for fast start (i.e. gas or diesel) generation units not fulfilling baseload production duties, start-up costs might be liable upon unit start-up following the receipt of dispatch instructions from the market operator.

Because of the significant õrun-upô time needed to go from a õcoldô start-up to a position where coal fired power stations can actually begin to supply power to the grid,[24] all coal plant was assumed to be synchronized with the grid so they can supply power.[25] In this case, minimum stable operating limits for such generators would be applicable for the complete 24 hour period being investigated and they therefore would not face start-up costs. Gas plant, on the other hand, has very quick start-up characteristics and can be synchronized with the grid and be ready to supply power within a half hour period of the decision to start-up. Therefore, in this case, the start-up decision and fixed start-up costs can accrue within the 24 hour dispatch period being investigated. Genuine peak plant and also OCGT plant that target day-time only (intermediate) operations would face this possibility.

The ANEMMarket model can be modified to incorporate such constraints and this generates a range of different, and more realistic simulations that we shall report elsewhere. The goal in this paper has been to explain how this model is constructed and the kinds of simulation results that can be obtained from it. We believe that such simulations can make a strong contribution to the debate concerning the impacts of carbon trading and, thus, to the formulation of effective carbon mitigation policies.

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[24] This process can take between 24 to 36 hours.

[25] We also assumed that NGCC plant also operated over the complete 24 hour period.

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Table 8. Incidence of Branch Congestion and Interconnector Power Transfers for BAU ($0/tC02) Scenario

Hour	Line 5	QNI	Directlink	Line 15	Line 19	Line 20	Line 24	NSW_VIC
01:00		432	7	X		X		-798
02:00		378	-9	X		X		-580
03:00		335	-22	X	X			-944
04:00		325	-25	X	X			-1075
05:00		351	-17	X		X		-968
06:00		417	3	X		X		-497
07:00		502	25	X		X		-218
08:00	X	574	48	X		X		22
09:00	X	638	69	X		X		225
10:00	X	675	81	X		X		362
11:00	X	694	88	X		X		425
12:00	X	729	93	X		X		622
13:00	X	796	99	X		X		237
14:00	X	845	101	X		X		-29
15:00	X	856	106	X		X	X	-205
16:00	X	907	103	X		X	X	-204
17:00	X	872	90	X		X		195
18:00	X	772	85	X		X		325
19:00	X	708	73	X		X		-49
20:00	X	819	74	X		X		-248
21:00	X	597	55	X		X		-232
22:00	X	521	28	X		X		-219
23:00		480	15	X		X		-545
24:00		448	7	X		X		-376

Table 8 (Cont). Incidence of Branch Congestion and Interconnector Power Transfers for BAU ($0/tC02) Scenario

Hour	Basslink	Line 43	Heywood	MurrayLink	Line 60	Line 61	Line 65	Line 68
01:00	-411		377	220		X	X	
02:00	-415		366	220		X	X	
03:00	-414		384	220		X	X	
04:00	-414		391	220		X	X	
05:00	-405		385	220		X	X	
06:00	-369		361	220		X	X	X
07:00	-461		332	220	X	X	X	
08:00	-448		315	220	X	X	X	
09:00	-451		304	220	X	X	X	
10:00	-457		296	220	X	X	X	X
11:00	-455		287	220	X	X	X	X
12:00	-454		201	145	X	X	X	X
13:00	-456	X	119	54	X	X	X	
14:00	-452	X	11	-50	X	X	X	
15:00	-450	X	-45	-106	X	X	X	
16:00	-454	X	-50	-110	X	X	X	X
17:00	-450	X	189	124	X	X	X	X
18:00	-458		299	220	X	X	X	X
19:00	-477		319	220	X	X	X	X
20:00	-479		332	220	X	X	X	X
21:00	-480		331	220	X	X	X	
22:00	-367		344	220		X	X	X
23:00	-394		364	220		X	X	
24:00	-416		354	220		X	X	

Table 9. Incidence of Branch Congestion and Interconnector Power Transfers for $100/tC02 Carbon Price Scenario

Hour	Line 5	QNI	Directlink	Line 15	Line 16	Line 20	Line 35	NSW-VIC
01:00		1143	122			X	X	1500
02:00		1151	119				X	1500
03:00		1146	115		X		X	1500
04:00		1141	113		X		X	1500
05:00		1151	118		X		X	1500
06:00		1000	92			X	X	1500
07:00		876	72			X	X	1821
08:00	X	762	52			X		1462
09:00	X	812	69	X		X		1489
10:00	X	845	81	X		X		1581
11:00	X	868	88	X		X		1449
12:00	X	881	93	X		X		1174
13:00	X	896	99	X		X		743
14:00	X	900	101	X		X		448
15:00	X	912	106	X		X		237
16:00	X	921	103	X		X		248
17:00	X	874	90	X		X		685
18:00	X	858	85	X		X		1228
19:00	X	820	73	X		X		1328
20:00	X	822	74	X		X		1129
21:00	X	767	55	X		X		1173
22:00	X	790	49			X		1053
23:00		954	81			X		1118
24:00		990	88			X	X	1500

Table 9 (Cont). Incidence of Branch Congestion and Interconnector Power Transfers for $100/tC02 Carbon Price Scenario

Hour	Basslink	Heywood	Murraylink	Line 60	Line 61	Line 65	Line 68
01:00	-594	-255	-168		X	X	
02:00	-594	-315	-220		X	X	
03:00	-594	-318	-220		X	X	
04:00	-594	-319	-220		X	X	
05:00	-594	-318	-220		X	X	
06:00	-594	-314	-220		X	X	
07:00	-594	-274	-161	X	X	X	
08:00	-594	-291	-197	X	X	X	
09:00	-594	-319	-220	X	X	X	
10:00	-594	-323	-220	X	X	X	X
11:00	-594	-319	-220	X	X	X	X
12:00	-594	-285	-220	X	X	X	X
13:00	-594	-255	-220	X	X	X	
14:00	-594	-235	-220	X	X	X	
15:00	-594	-221	-220	X	X	X	
16:00	-594	-222	-220	X	X	X	X
17:00	-594	-267	-220	X	X	X	X
18:00	-594	-300	-220	X	X	X	X
19:00	-594	-310	-220	X	X	X	X
20:00	-594	-299	-220	X	X	X	X
21:00	-594	-302	-220	X	X	X	
22:00	-594	-282	-220		X	X	X
23:00	-594	-272	-206		X	X	
24:00	-594	-255	-172		X	X	

Figure 1. QLD 11 Node Model - Topology

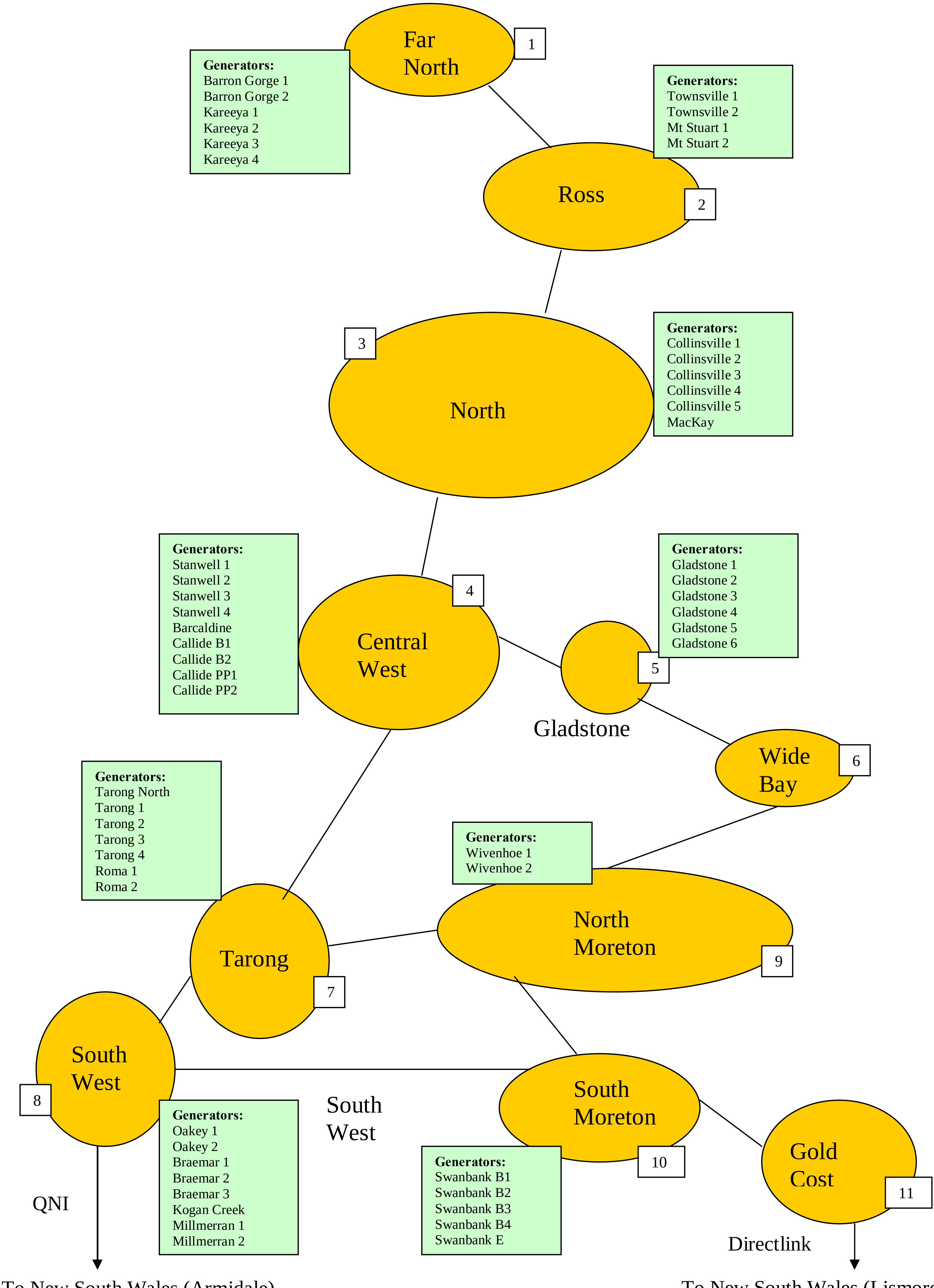
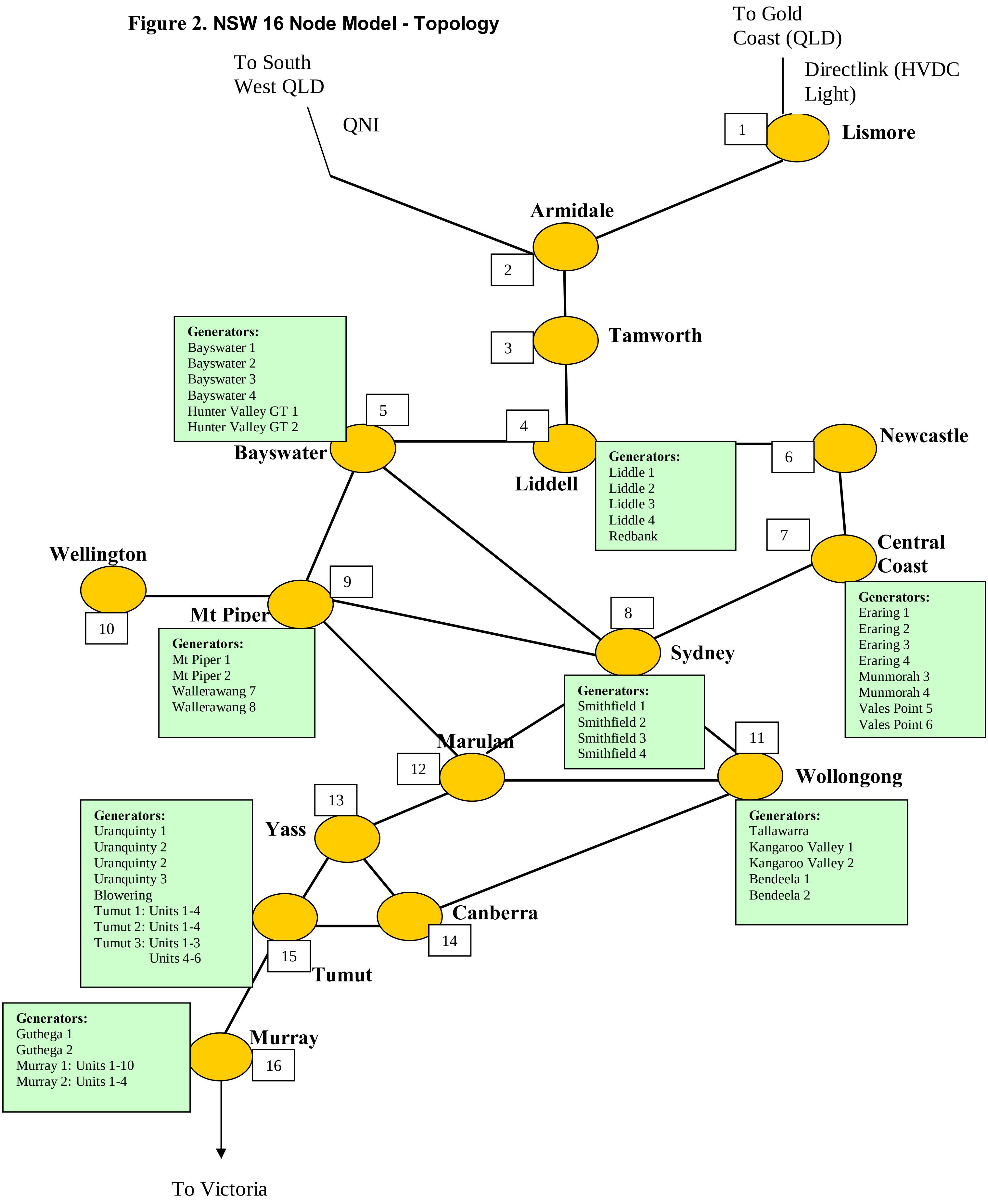


Figure 2. NSW 16 Node Model - Topology



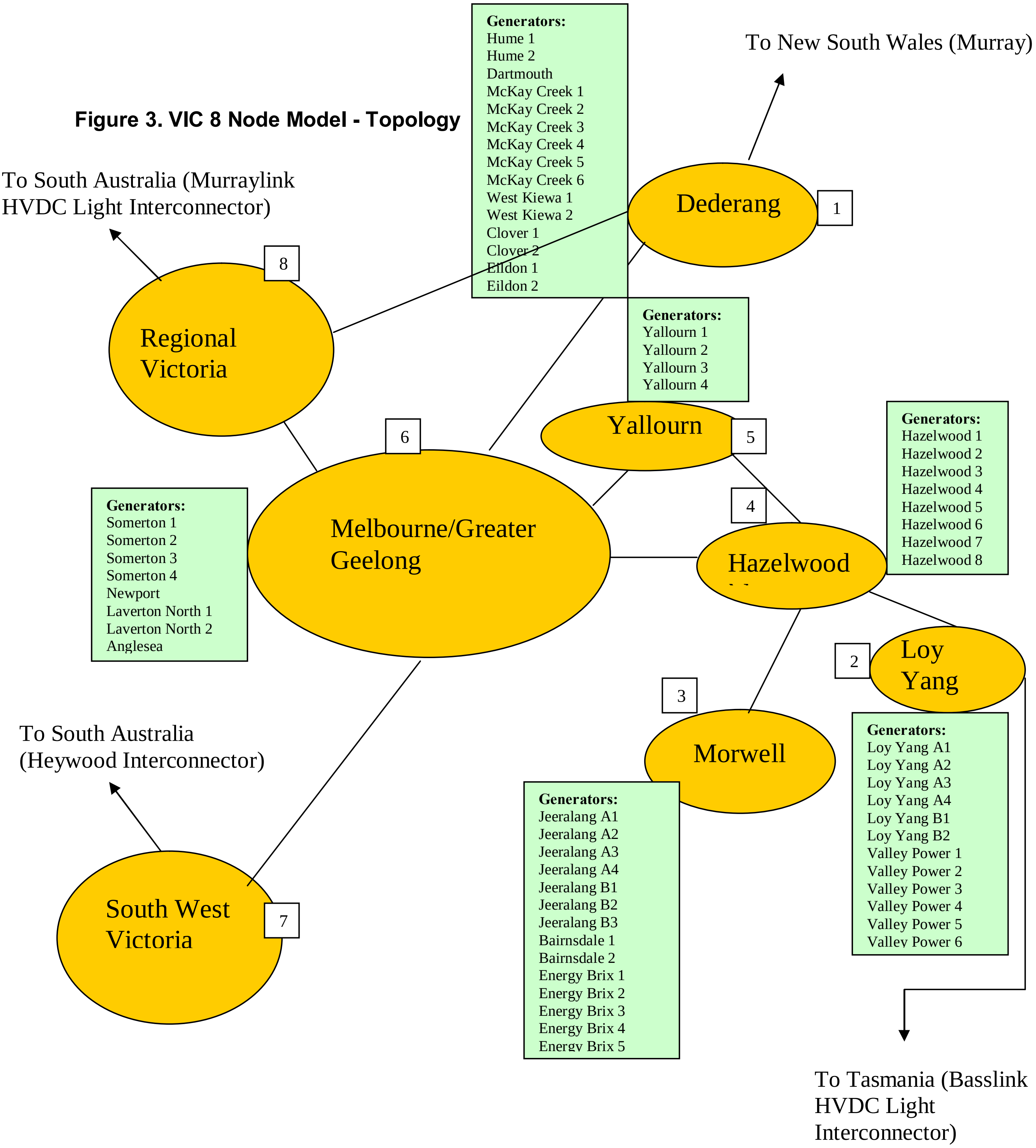


Figure 3. VIC 8 Node Model - Topology

Figure 4. SA 7 Node Model - Topology

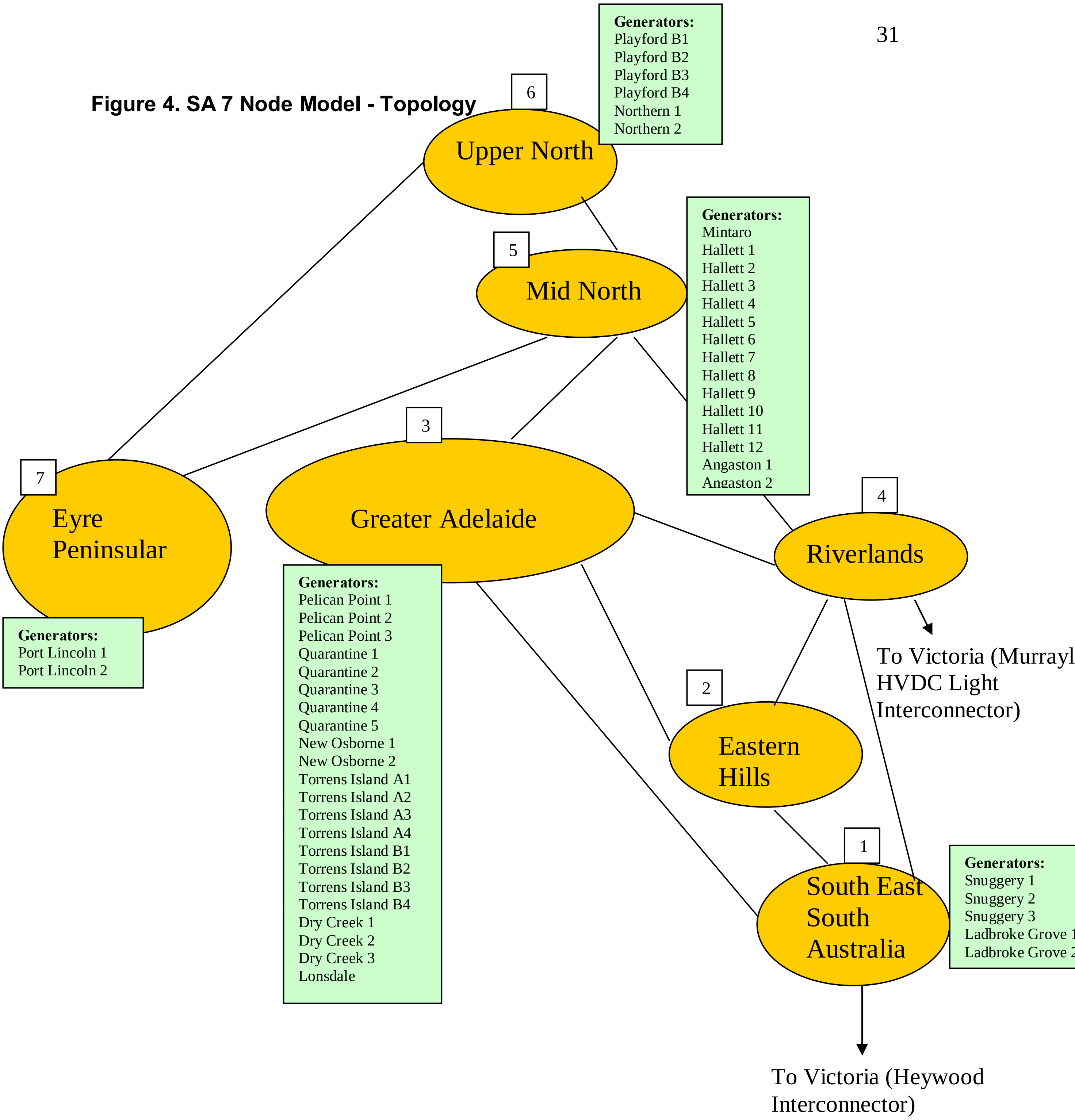


Figure 5. Tasmanian 11 Node Model - Topology

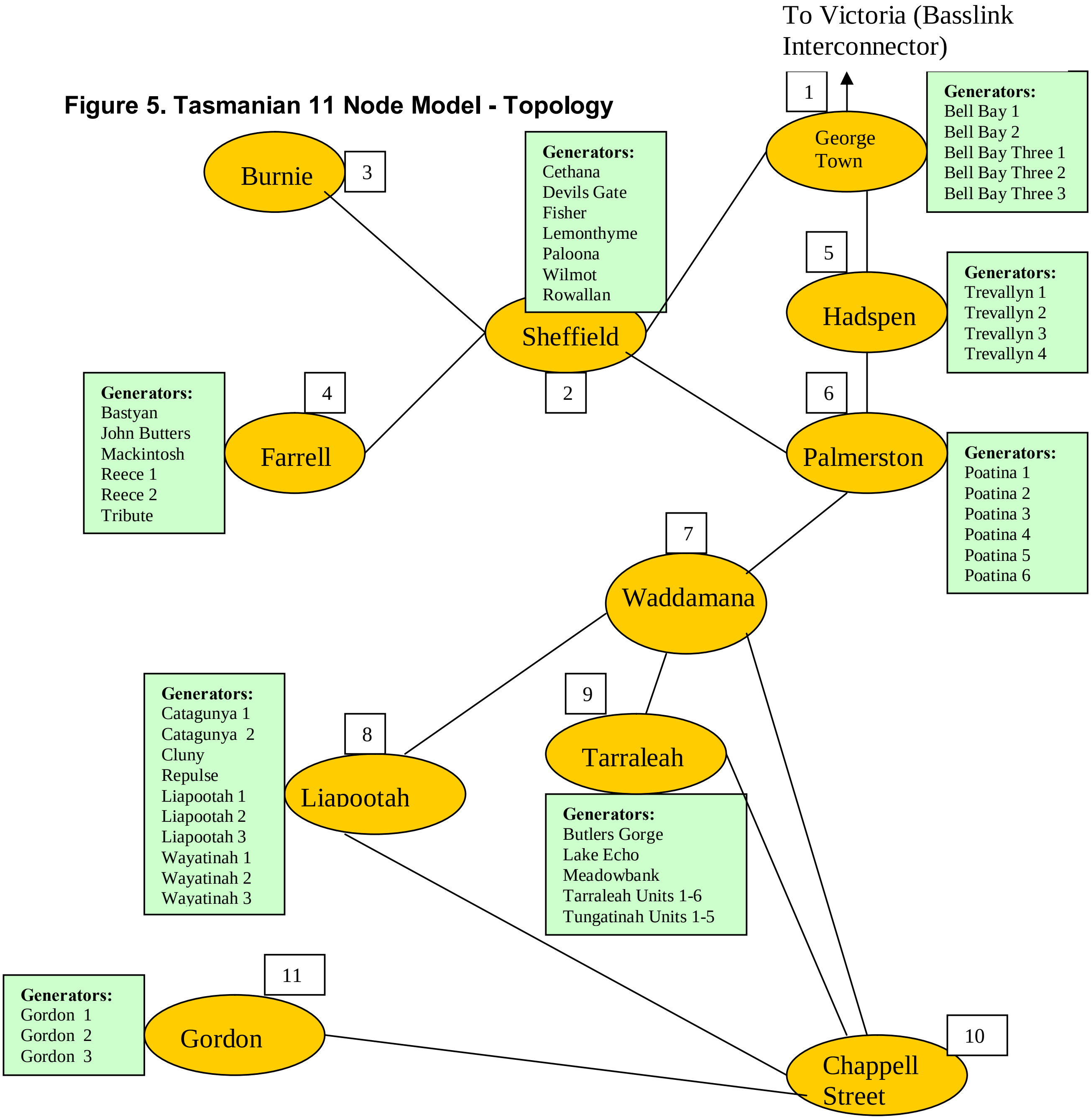


Figure 6. Plot of Optimal Hourly System Variable Cost

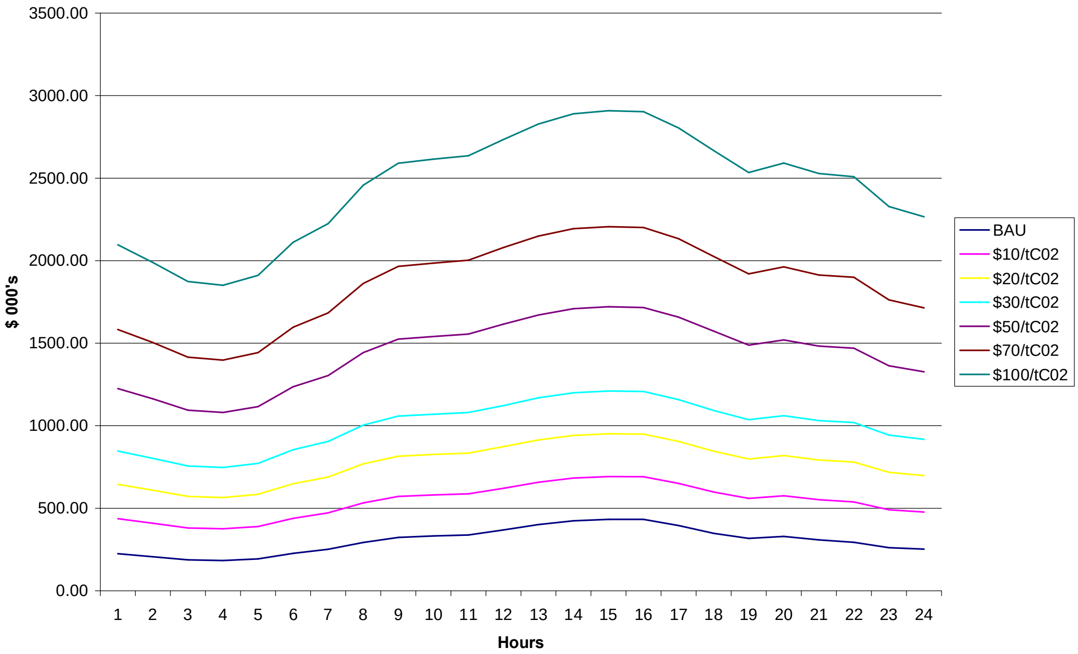


Figure 7. Plot of Average Hourly Electricity Price for Various Carbon Price Scenarios

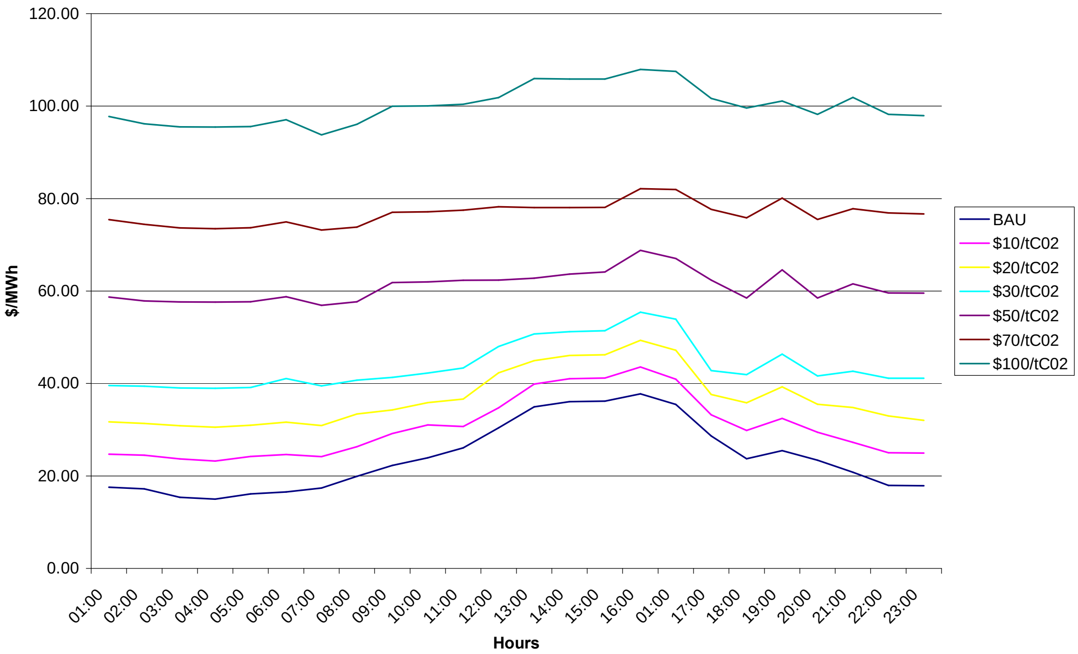


Figure 8a. Plot of Average Hourly Nodal Price Variations for 'BAU' ($0/tC02) Scenario

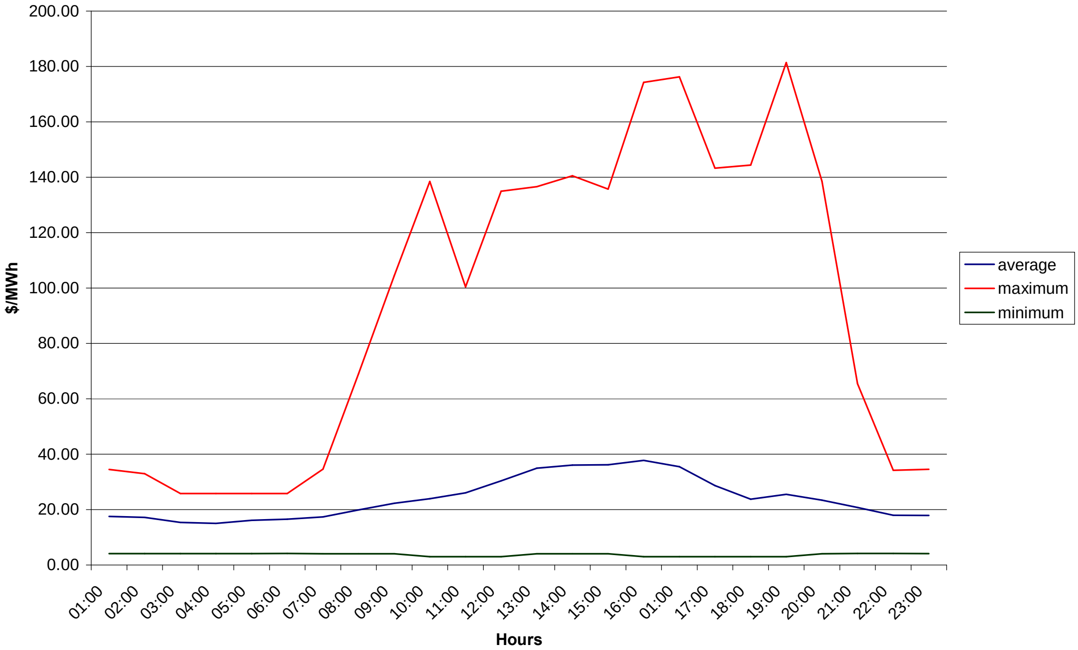


Figure 8b. Plot of Average Hourly Nodal Price Variations for ($20/tC02) Scenario

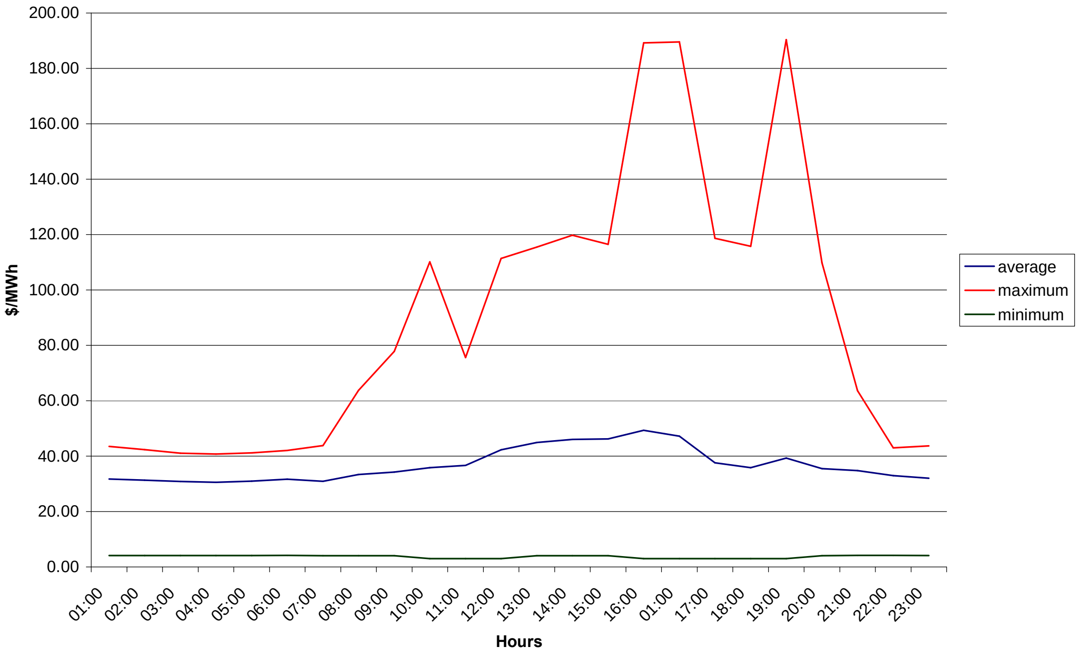


Figure 8c. Plot of Average Hourly Nodal Price Variations for ($50/tC02) Scenario

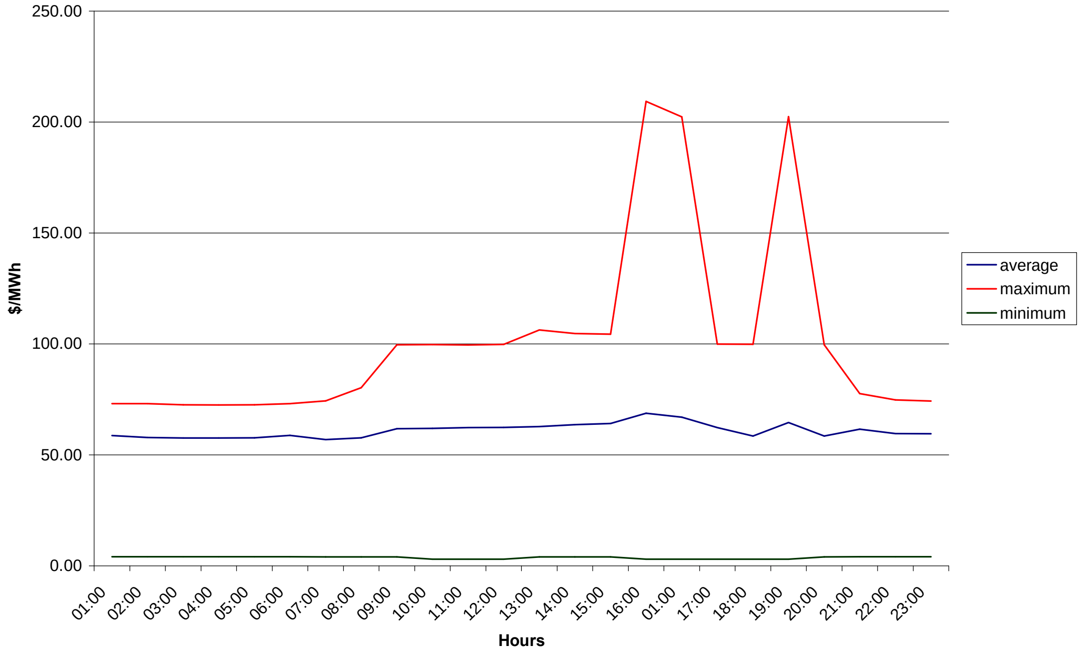


Figure 8d. Plot of Average Hourly Nodal Price Variations for ($70/tC02) Scenario

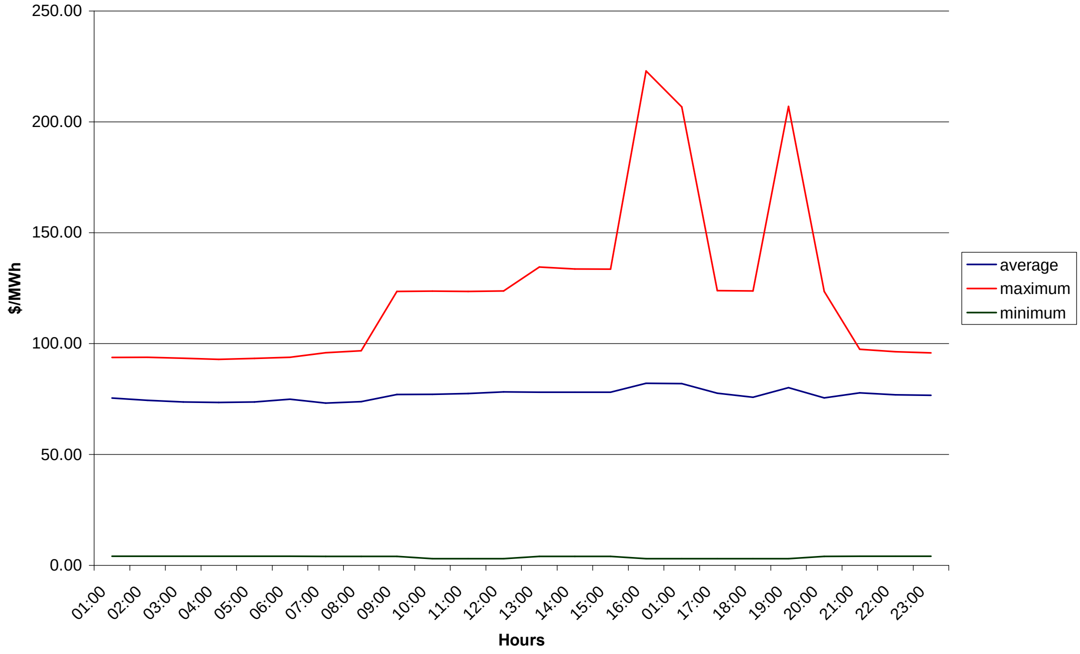


Figure 8e. Plot of Average Hourly Nodal Price Variations for ($100/tC02) Scenario