Intra-Day Uncertainty and Efficiency in Electricity Markets

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Abstract

The goal of an electricity market is to provide incentives for suppliers and transmission companies to produce and distribute electric power in an efficient and reliable manner. This study was conducted for the purpose of assessing the value of a day-ahead market structure for New Zealand's wholesale electricity market. Single-settlement markets like New Zealand's market can reduce efficiency due to uncertainty, loss of generation coordination, and exercise of market power. We build models of New Zealand's electricity system for the purpose of assessing these particular sources of inefficiency in New Zealand's electricity market. The models simulate various market structures aimed at isolating the sources of inefficiency. The models are structured around the vSPD model framework, which utilizes a full 285 node representation of New Zealand's transmission system. The vSPD model is altered to include explicit modeling of New Zealand's major hydro schemes. Our experiments indicate lack of coordination of generation to be the most significant cause of inefficiency in New Zealand. The combined effect of exercise of market power and other smaller effects were estimated to be next biggest contributor to inefficiency, and uncertainty had a negligible effect.

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Contents

Chapter 1

Introduction

1.1 Motivation

New Zealand's electricity market pricing and dispatch mechanism is a bid-based, security constrained economic dispatch with nodal pricing. Other markets with a similar structure are the PJM Interconnection, New York, and Norway (although Norway's locational pricing mechanism is different from New Zealand's, see section 1.6.1.1) [29]. The major point of difference between these three markets and the New Zealand wholesale electricity market is that they include markets for both day-ahead trading and real time trading, whereas New Zealand's electricity market has only a real-time market. A day-ahead market can reduce the loss of efficiency due to uncertainty, coordination of generation, and exercise of market power.

This thesis develops models to assess the value of a day-ahead electricity market in New Zealand. Each model presented in this thesis simulates a different market structure under various assumptions. Comparing the output of these models allows us to isolate each of the sources of ineffiency mentioned above.

1.2 New Zealand Wholesale Electricity Market

New Zealand's wholesale electricity market pricing and dispatch mechanism is known as a bid-based, security constrained economic dispatch with nodal pricing. The wholesale functions of New Zealand's electricity market include bidding, offering, scheduling, dispatch, pricing and clearing and settlement. The wholesale market is composed of sellers (generators) and purchasers (retailers and large electricity consumers) [14]. Trading occurs at 285 nodes across New Zealand's national grid. These nodes consist of 226 grid exit points (GXPs) and 59 grid injection points (GIPs) [6]. There are five main gentailers (a portmanteau of generator and retailer): Meridian Energy, Contact Energy, Mighty River Power, Genesis Energy, and Trustpower. In 2011, these gentailers had a market share of 32%, 22%, 17%, 15%, and 6%, respectively [9].

1.2.1 Generation Offers and Bids

Generators submit to the System Operator (currently Transpower) offers to sell electricity for each trading period of the following day for each grid injection point at which the generators want to sell electricity. These offers are submitted by 1 PM of the current day for each trading period of the following day. Generators are able to amend or cancel offers up to 2 hours prior to that offer's trading period [4]. This is called a two-hour gate closure. Each offer comprises up to 5 price bands, or tranches [5]. Each tranche is composed of a quantity, in MW, and a price, in \$/MWh. The offer price must increase from tranche to tranche. In addition, each offer must contain the maximum capacity, ramp up rate, and ramp down rate for the particular grid exit point. Stations with generating capacity less than 10 MW are not required to submit offers. There is no obligation for a generator to offer any volume and there is no maximum offer price. However, offer prices must be non-negative. Offers can be specific to a single generating unit or they can be specific to generating stations. Intermittent generators, such as wind farms, must offer their generation at $0.00 or $0.01/MWh [4].

Purchasers submit to the System Operator bids to purchase electricity for each trading period of the following day for each grid exit point that the purchaser wants to buy electricity. As with generator offers, the bids are to be submitted by 1pm of the current day for each trading period of the following day. There is a 2-hour gate closure for bids, that is, purchasers are able to amend or cancel their bids up to two hours before that bid's trading period. Each bid comprises up to 10 price bands, or tranches. Each bid tranche is composed of a quantity, in MW, and a price, in $/MWh. There is no obligation to submit a bid, and there is no limit for the maximum bidding price. However, the bidding price must be non-negative [4].

1.2.2 Reserve

If a party has a contract with the System Operator to provide reserve, it is allowed to submit reserve offers. As with generation offers, reserve offers are submitted to the System Operator for the trading periods of the following day at 1pm of the current day at the grid exit point or grid injection point specified. There is a two-hour gate closure for amendment and cancellation of reserve offers. There are three classes of reserve in the New Zealand Electricity Market. These are:

Partially Loaded Spinning Reserve

As the name implies, a hydroelectric station in Partially Loaded Spinning Reserve (PLSR) mode is operating in its normal generating mode, but not at its full generating capacity. Additional power can be obtained by releasing more generating flow through the station.

Tail Water Depressed Spinning Reserve

When a hydroelectric plant is operating under Tail Water Depressed Spinning Reserve (TWDR) mode, its generator is running at system frequency without any water passing through it. When a loss of power occurs, a station in TWDR mode can very quickly provide additional power [22].

Interruptible Load

Interruptible load is provided by load that can quickly and easily be reduced.

Each reserve offer can be submitted for one or both of the following:

Fast Instantaneous Reserve

Fast Instantaneous Reserve (FIR) is available within six seconds of an unexpected generator or transmission outage. Fast Instantaneous Reserve must be able to run for one minute. The total amount of FIR is dependent on the on the size of the single largest potential transmission or generator outage in a particular period.

Sustained Instantaneous Reserve

Sustained Instantaneous Reserve (SIR) is available within sixty seconds of an unexpected generator or transmission outage. Sustained Instantaneous Reserve must be able to run for fifteen minutes. The total amount of SIR is dependent on the on the size of the of single largest potential transmission or generator outage in a particular period [15].

There can be up to three reserve offer tranches and the price offered must increase from tranche to tranche. There is no upper limit for reserve offered and offer prices must be non-negative. The total reserve and generation offer for a particular station must not exceed the capacity of the station [4].

1.2.3 SPD and vSPD

All offers and bids are passed to the System Operator, who passes the offers and bids to the Scheduling, Pricing and Dispatch (SPD) model. This model takes the offers and bids, transmission, generator, and demand data, and produces a system optimal generation and reserve schedule for each generator and the resulting prices for each grid node for every half-hourly trading period for up to 36 hours ahead [14]. The nodal pricing scheme implemented in the New Zealand market is a uniform pricing scheme. Therefore, the price of electricity at each node is the marginal cost of delivering electricity to that node. The SPD model includes constraints that the System Operator may impose on generation, reserve, and purchasing for the purpose of network security. SPD also has the ability to add integer variables that resolve issues such as circulating branch flows and non-physical transmission losses. For more information on the constraints, parameters and variables involved in the SPD model, refer to the SPD Model Formulation [11].

SPD is solved every five minutes in order to find the optimal system dispatch and provide an indicative price for the previous five minute period [7]. The system operator issues dispatch instructions to the offering generators. These dispatch instructions are, in general, for the provision of generation, reserve, frequency support, voltage support, and for the management of security constraints. The system operator may also issue instructions to offerers of interruptible load [4].

Certain groups of stations are block-dispatched. This means that the total generation across the block dispatch group is to equal the total generation dispatched by SPD, but the individual stations' generation need not be equal to their generation dispatched by SPD. The Waikato Hydro Scheme is an example of a station group that is block dispatched. In addition, the system operator solves SPD in order to produce a pre-dispatch schedule. The pre-dispatch schedule is solved, and the system operator publishes the following information for each trading period:

- The expected supply and demand curves for the reference nodes Benmore and Haywards.
- The disconnected GXPs and GIPs and the location of any infeasibilities.

- Instantaneous island reserve and the reserve offer stack for each island.
- The indicative frequency keeping stations for each island
- Expected HVDC flows and HVDC risk offsets.

Each generator and purchaser receives information relating only to their generation and demand. The pre-dispatch schedules are generated no more than two hours apart. In addition to the pre-dispatch schedule, the system operator publishes dispatch prices, dispatch quantities, HVDC flows and other information for at least the next seven trading periods. This information assists generators and purchasers in making their planning decisions [4].

Vectorised Scheduling, Pricing and Dispatch (vSPD), developed by the Electricity Authority, is a free clone of Transpower's SPD software. vSPD was developed in the mathematical modelling system GAMS. vSPD differs from SPD in the addition of the vectorisation feature, which allows vSPD to be solved in a single run, as opposed to SPD which is solved sequentially in terms of trading period. Also, vSPD is typically solved over a 24 hour horizon, unlike the 36 hour horizon over which SPD is solved [13]. vSPD's full market representation of New Zealand's national grid, as well as its built-in outage and market constraint data, makes it the perfect framework for developing the system-wide optimisation models for this project.

1.3 Hydrology of New Zealand's Hydroelectric Schemes

Hydroelectricity accounted for 57% of New Zealand's generation in 2011 [9]. Therefore, a large part of this study is modelling the physical operation of New Zealand's four largest hydroelectric power schemes. These schemes are the Waikato, Waitaki, Clutha, and Manapouri schemes. In order to model these schemes, we must first gain an understanding of the general characteristics of a hydroelectric scheme, as well as the specific aspects of New Zealand's hydro power schemes.

1.3.1 Characteristics of Hydroelectric Power Schemes

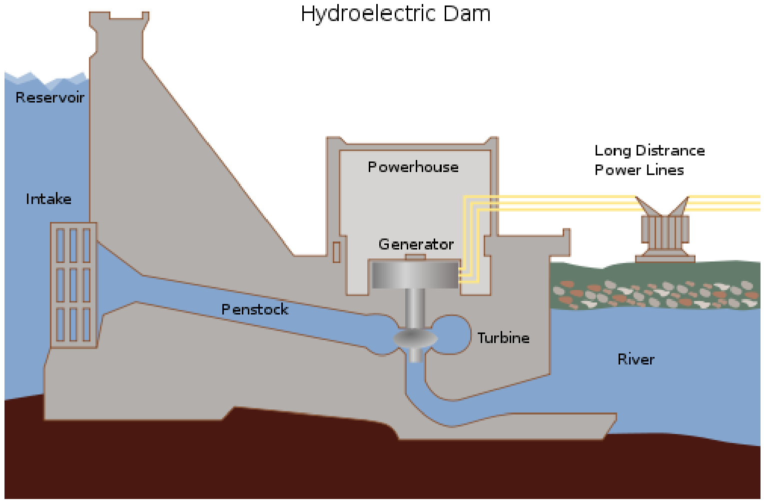

Figure 1.1: Hydroelectric Station Diagram [44]

Figure 1.1 shows the important components of a hydroelectric station. Flow from the reservoir into the powerhouse is controlled by the intake gates. The penstocks carry the water from the reservoir into the powerhouse, which houses the station's turbines. The turbine is composed of a scroll case, a runner, and a draft tube. The scroll case is a spiral structure surrounding the turbine which forces the water to take on a spiral motion with which to drive the blades of the runner. The mechanical energy of the runner blades is converted into electrical energy by the generator. The water then passes through the draft tube, which is designed to slow the outflow of water and maintain the pressure head. The spillway gates and diversion gates are used to control the reservoir levels. Spilled water does not generate any electricity, therefore the amount of water spilled is to be kept to a minimum. The spillway gates are used more frequently than the diversion gates, which are used primarily for emergency level control. Reservoirs have minimum and maximum consented reservoir levels that must be adhered to. Most stations, spillways, and canals have maximum consented flow rates and some even have minimum flow rates that must be adhered to.

Figure 1.2 shows a number of important parameters that determine the output of a hydroelectric turbine. The head measurement in Figure 1.2 is the gross head. The station's net head is given as the gross head minus head loss due to friction. The power output of a hydroelectric turbine can be calculated as $P = \rho g h_n V A \eta$, where ρ is the density of water, g is the acceleration due to gravity, h_n is net head, V is the flow velocity in the penstock, A is the penstock area, and η is the turbine efficiency.

Each hydroelectric station has at least one operating unit, or turbine. Units can be switched on and off, incurring a cost. The major operational decisions that need to be made are the unit commitment and load dispatch. The unit commitment determines which units are operating during each trading period. The load dispatch is a schedule of water releases for a particular unit commitment [43]. Hydro planners need to choose a unit commitment and corresponding load dispatch that will maximise expected profit and meet system constraints over the planning horizon.

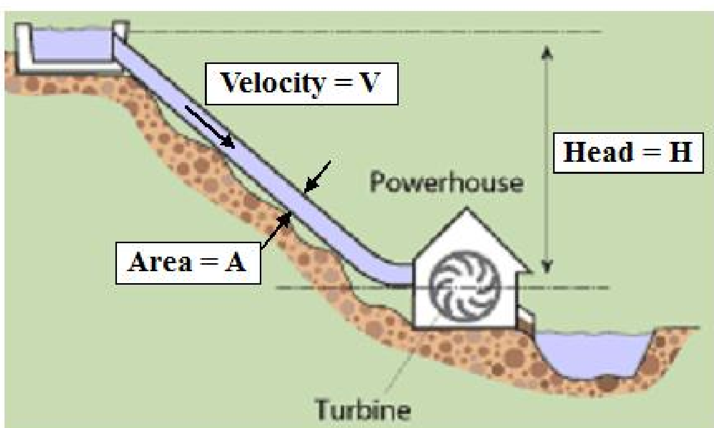

Figure 1.2: Key Parameters for a Hydroelectric Station [42]

For a single reservoir hydroelectric system, a station's inflows influence its volume, which influence the station's head, which influences the station's generating flow and station efficiency. These, in turn, influence the station's reservoir volume and generation. In a multi-reservoir, or cascaded hydroelectric system, the relationship is more complex, as outflows from an upstream station affect the volume, head, and station efficiency of the downstream stations. Due to uncertain factors, such as demand and pricing, and the nonlinear station efficiencies, the problem of optimising the profit of a hydroelectric scheme is a stochastic non-linear problem [25]. Furthermore, there is a significant geographical distance between some cascaded hydroelectric stations. Therefore, for some stations, there are significant delays between flow release from an upstream station and flow arrival at the downstream station.

1.3.2 Waikato Power Scheme

The Waikato River is located in New Zealand's North Island. The Waikato River begins as the Tongariro River, which empties into Lake Taupo, and continues from Lake Taupo through the Hamilton Basin and enters the sea at Port Waikato. The Waikato River is New Zealand's longest river [38]. The Waikato River Chain consists of nine lakes and eight stations, as shown in Figure 1.3. In order of upstream to downstream, the nine lakes are Lake Taupo, Lake Aratiatia, Lake Ohakuri, Lake Atiamuri, Lake Whakamaru, Lake Maraetai, Lake Waipapa, Lake Arapuni, and Lake Karapiro. These are listed along with their storage capacities in Table 1.1. The nine stations are Aratiatia, Ohakuri, Atiamuri, Whakamaru, Maraetai 1, Maraetai 2, Waipapa, Arapuni, and Karapiro. All stations on the Waikato River are owned by Mighty River Power. For simplicity, we aggregate Maraetai 1 and Maraetai 2 into a single station. We list the stations and generation data in Table 1.2.

Lake	Volume	Inflow
Lake Taupo	848,624,230	Yes
Lake Aratiatia	717,120	Yes
Lake Ohakuri	13,504,320	Yes
Lake Atiamuri	2,877,120	Yes
Lake Whakamaru	10,549,440	Yes
Lake Maraetai	8,208,000	Yes
Lake Waipapa	1,105,920	Yes
Lake Arapuni	9,547,200	Yes
Lake Karapiro	13,936,320	Yes

Table 1.1: Waikato Hydrology Data [26]

Station	Capacity (MW)	Conversion Factor (MW/cumec)
Aratiatia	78	0.2703
Ohakuri	112	0.2778
Atiamuri	84	0.2041
Whakamaru	100	0.3125
Maraetai	360	0.5000
Waipapa	55	0.1429
Arapuni	196.7	0.4348
Karapiro	100	0.2632

Table 1.2: Waikato Generator Data [26]

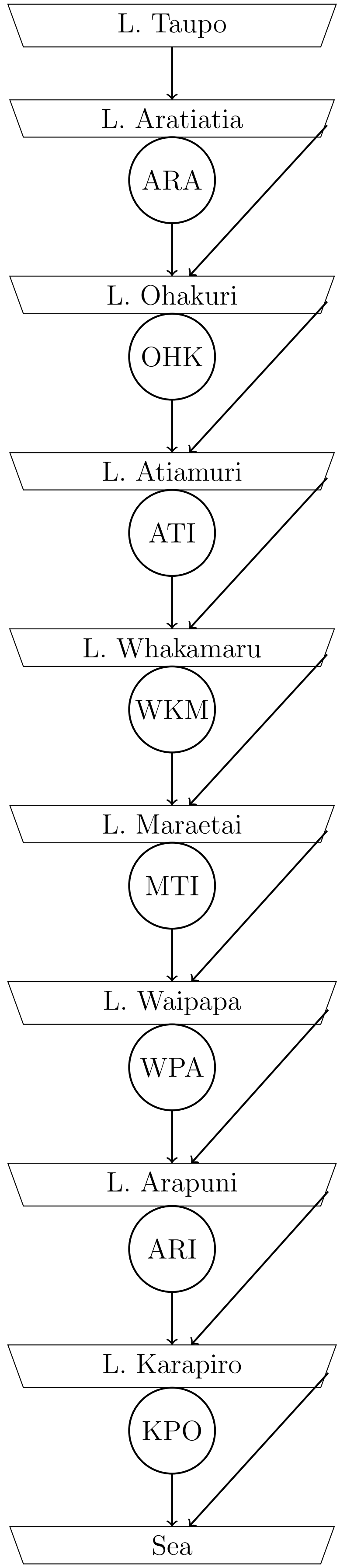

Figure 1.3: Diagram of Waikato Power Scheme

1.3.3 Waitaki Power Scheme

The Waitaki Power Sheme is located in the Canterbury and Otago regions of New Zealand's South Island. The scheme begins at Lake Tekapo, which feeds the Tekapo-Pukaki Canal. After Lake Pukaki, the scheme continues along the Ohau River, which empties into Lake Ruataniwhi. The final stretch of the Waitaki Scheme is the Waitaki River, which flows through Lakes Benmore, Aviemore, and Waitaki [31] [23]. The Waitaki Power Scheme consists of eight hydroelectric stations as well as 10 lakes and headponds, as shown in Figure 1.4. The eight stations, from upstream to downstram are Tekapo A, Tekapo B, Ohau A, Ohau B, Ohau C, Benmore, Aviemore, and Waitaki. The 10 lakes and headponds are Lake Tekapo, Lake Scott, Tekapo B headpond, Lake Pukaki, Lake Ohau, Lake Ruataniwha, Ohau C headpond, Lake Benmore, Lake Aviemore, and Lake Waitaki. The storage capacities for these lakes are given in Table 1.3. As well as the lakes and headponds, there are a number of junctions, where flows from different lakes, headponds, and stations are combined, but water does not accumulate, i.e. flow into a junction equals flow out of a junction.

The Tekapo A and Tekapo B stations are owned by Genesis Energy, and all other stations on the Waitaki Scheme are owned by Meridian Energy. However, the data used in this study come from a time when Tekapo A and Tekapo B were owned by Meridian Energy, therefore, these stations are assumed to be owned by Meridian Energy for the purpose of this thesis. We list the stations and generation data in Table 1.4.

Lake	Volume (m^3)	Inflow
Lake Tekapo	823,190,000	Yes
Lake Scott	79,920	No
Tekapo B Headpond	10,751,132	No
Lake Pukaki	2,425,440,000	Yes
Lake Ohau	57,245,219	Yes
Lake Ruataniwha	1,454,225	No
Ohau C Headpond	43,215,676	No
Lake Benmore	423,451,076	Yes
Lake Aviemore	89,194,289	Yes
Lake Waitaki	19,466,601	Yes

Table 1.3: Waitaki Scheme Hydrology Data [26]

Station	Capacity (MW)	Conversion Factor (MW/cumec)
Tekapo A	25.1	0.2436
Tekapo B	160.1	1.297
Ohau A	264.2	0.4790
Ohau B	212.2	0.4251
Ohau C	212.2	0.4251
Benmore	540.4	0.8214
Aviemore	230.2	0.3175
Waitaki	105	0.1751

Table 1.4: Waitaki Scheme Generator Data [26]

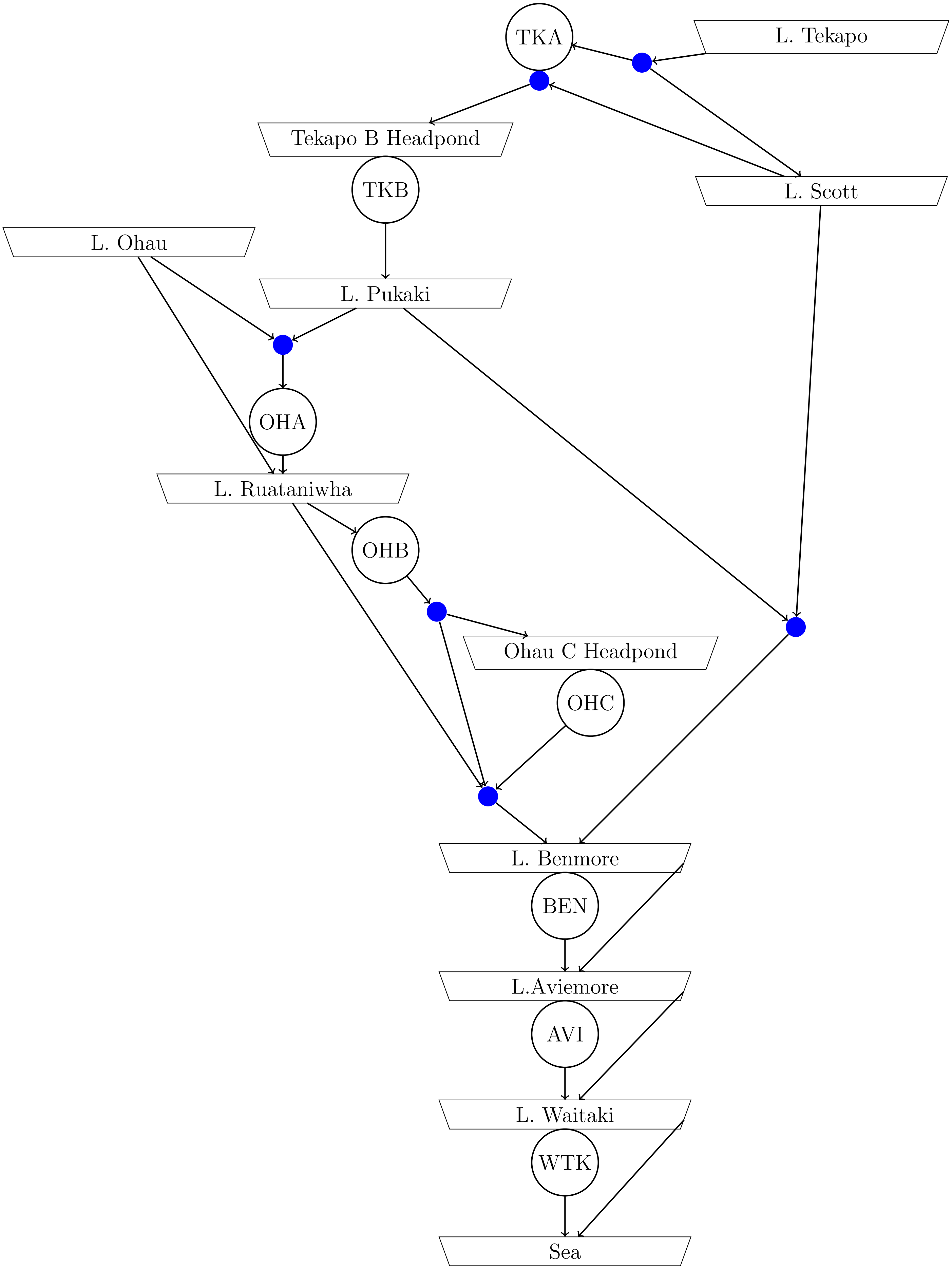

Figure 1.4: Diagram of Waitaki Power Scheme

1.3.4 Clutha Power Scheme

The Clutha River is located in the Central Otago region of New Zealand's South Island. The Clutha River, which starts at Lake Wanaka, and empties into the Pacific Ocean, is the longest river in the South Island and the second longest river in New Zealand [35]. The Clutha River Chain consists of two hydroelectric stations and four lakes, as shown in Figure 1.5. The stations on the Clutha Scheme are Clyde and Roxburgh. The station and generation data are given in Table 1.6. The lakes are Lake Wanaka, Lake Hawea, Lake Dunstan, and Lake Roxburgh. The lakes and their storage capacities are listed in Table 1.5. Clyde and Roxburgh stations are owned by Contact Energy.

Lake	Volume (m^3)	Inflow
Lake Hawea	1,378,764,328	Yes
Lake Dunstan	25,200,000	Yes*
Lake Roxburgh	10,324,800	Yes

Table 1.5: Clutha Hydrology Data [26]

*The inflows for Dunstan include the inflows for Lake Wanaka.

Station	Capacity (MW)	Conversion Factor (MW/cumec)
Clyde	464	0.5128
Roxburgh	334	0.3876

Table 1.6: Clutha Generator Data [26]

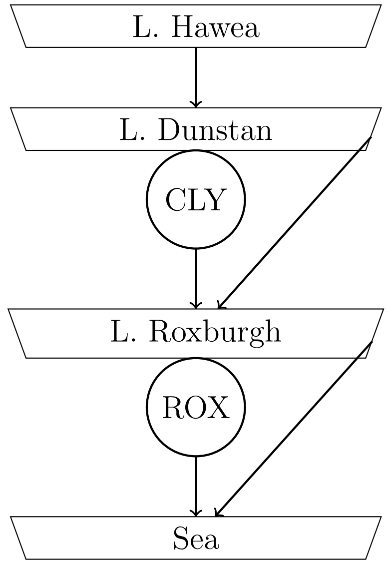

Figure 1.5: Diagram of Clutha Power Scheme

1.3.5 Manapouri Power Scheme

The Manapouri Power Station is located in Fiordland National Park in New Zealand's South Island. Manapouri is the largest hydro station in New Zealand. Construction of Manapouri began in the 1960s, with the intent of using Manapouri to power an aluminium smelter in Bluff [24]. The Manapouri Power Scheme consists of one hydroelectric station and two lakes. The two lakes are Lake Manapouri and Lake Te Anau and the hydroelectric station is Manapouri Station. Manapouri Station is owned by Meridian Energy.

Lake	Volume (m^3)	Inflow
Lake Manapouri*	1,501,878,016	Yes

Table 1.7: Manapouri Hydrology Data [26]

*The inflows for Lake Manapouri are modelled as the sum of the Lake Te Anau inflows and the Lake Manapouri inflows. The volume capacity for Manapouri is also modelled as the sum of the Lake Manapouri volume and Lake Te Anau volume.

Station	Capacity (MW)	Conversion Factor (MW/cumec)
Manapouri	885	1.5180

Table 1.8: Manapouri Generator Data [26]

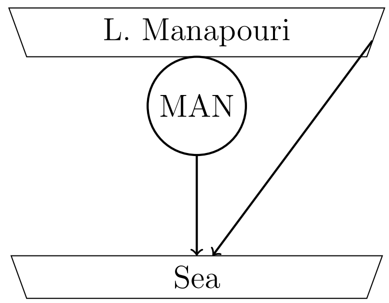

Figure 1.6: Diagram of Manapouri Hydro Scheme

1.4 Thermal and Geothermal Generation

Gas, coal, and geothermal energy made up 18.4%, 13.4%, and 4.7% of New Zealand's generation, respectively, in 2011. Diesel makes up a significantly smaller share of New Zealand's electricity generation [9].

Geothermal power stations use steam or hot water from beneath the earth's surface to drive their turbines. No fuel is required to run a geothermal stations, therefore the marginal production cost for geothermal stations is very low. Because of this, geothermal stations are offered into the market at zero price. Geothermal stations are base-load stations, meaning they are usually run at their full capacity [32]. Because geothermal stations are typically offered in at their generating capacity, our models assume geothermal stations are operated continuously at capacity.

Gas, Coal, and Diesel stations, on the other hand, have relatively high marginal costs and are not operated as base-load stations. Due to their relatively high marginal cost and the approximately 32% share of energy produced from gas, coal, and diesel in the New Zealand electricity market, the modelling of these stations is important in this study. As with hydroelectric stations, thermal stations have one or more operating units. These units can be switched on and off, incurring a cost. The unit commitment problem is important for optimising thermal stations. The total cost of the problem is the sum of production cost and the cost associated with switching units on and off. Additionally, there is a limit to the rate at which thermal units can change their output. These limits are called ramping constraints. Thermal units typically have non-linear production cost functions. Thermal unit efficiency is known as the heat rate. The heat rate gives the amount of input energy, in GJ, required to produce a MWh of electric energy. The marginal production cost is given as the product of the heat rate (in GJ/MWh) and the wholesale cost of fuel (in $/GJ).

Natural gas is typically traded through take-or-pay contracts, which ensure that the natural gas suppliers are paid an equal amount regardless of how much gas is used by the purchasers [28]. Coal is stored in large stockpiles that are replenished periodically. Coal shortages may lead to temporarily high opportunity costs [26].

The major natural gas stations that we model in our experiments are Otahuhu B, Huntly 5 and 6, Southdown, and Stratford. We also choose to include the natural gas cogeneration station Te Rapa, since its fuel availability is not limited by the production of the plant at which it is situated. The major coal stations are Huntly 1-4. Whirinaki is the only major diesel power station in New Zealand. The major thermal stations and their generating data are given in Figure 1.7.

Station	Capacity (MW)	Heat Rate (GJ/MWh)	O&M Cost ($/MWh)	Fuel
Huntly 1	260	10.5	9.6	Coal
Huntly 2	260	10.5	9.6	Coal
Huntly 3	260	10.5	9.6	Coal
Huntly 4	260	10.5	9.6	Coal
Huntly 5	430	6.8	4.25	Gas
Huntly 6	50	9.5	6.4	Gas
Otahuhu B	396	7.05	4.3	Gas
Whirinaki	159	11	6.4	Diesel
Stratford (TCC)	387	7.3	4.3	Gas
Stratford	210	10	6.4	Gas
Te Rapa	44	10.6	6.4	Gas
Southdown 1	125	8.7	4.3	Gas
Southdown 2	48	10	6.4	Gas/Steam

Figure 1.7: Thermal Generator Data [16] [26]

1.5 Wind and Other Generation

Wind generation accounted for 4.5% of New Zealand's total generation in 2011. Wind generation has grown very quickly in recent times, at an average of 30% annual growth over the decade preceding 2011. The largest wind farm in New Zealand is TrustPower's 161 MW Tararua wind farm [9]. Wind power is an intermittent source of electricity, therefore, predicting the availability of wind generation is an important problem for developing accurate pre-dispatch schedules and prices. The Electricity Authority monitors the accuracy of the generators' wind forecasts and has published a quarterly review. Figure 1.8 below plots the actual wind generation against the forecasted wind generation for a New Zealand wind farm. We see that when high winds have been predicted, there is typically a non-zero generation at the wind farm. On average the forecasts are overestimated for forecasts greater than approximately 12 MW. For forecasts lower than approximately 12 MW, we see underestimated forecasts on average. This graph exemplifies the difficulty involved with forecasting wind generation [8].

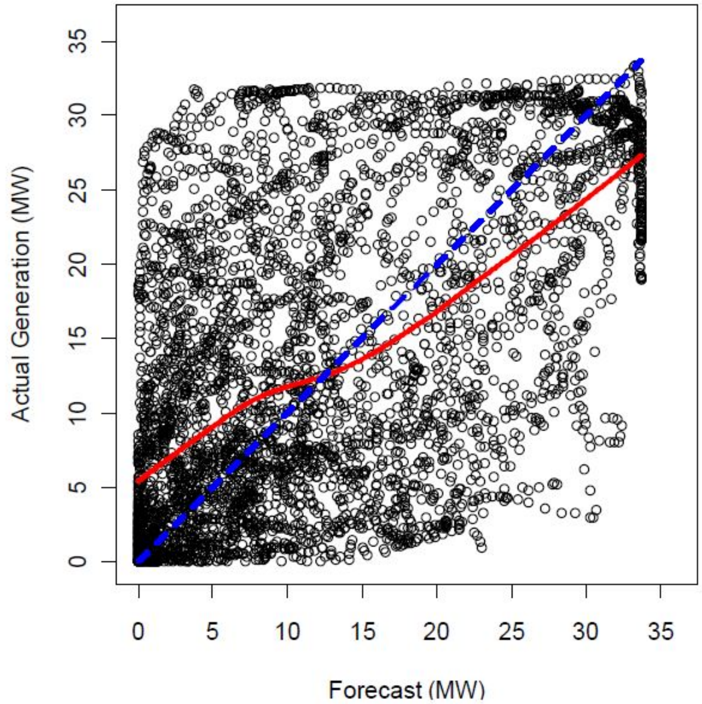

Figure 1.8: Analysis of Forecasted and Actual Wind Generation [8]

1.6 Day-Ahead Electricity Markets

A day-ahead electricity market is one where electricity is traded the day prior to being generated, as opposed to a real-time market where electricity is traded much nearer to the time at which it is generated. A further point of difference between a day-ahead market and a real-time market is that a real-time market is purely physical, whereas a day-ahead market will allow both physical and financial transactions. With financial power transactions, the purchaser is not guaranteed delivery of power. The purchaser is financially compensated for any power that is undelivered. Physical transactions always result in delivery of electrical power. A day-ahead market is typically combined with a real-time market, where the real-time market can be used to balance excess supply not met by the day-ahead market. In practice, the real-time market and day-ahead market should be distinct. This is known as a two-settlement market. In a two-settlement market, deviations are settled using the real-time price, i.e. if the day-ahead dispatch exceeds demand, generators buy back their surplus generation at the real-time price, and if day-ahead dispatch does not meet demand, generators sell further generation at the real-time price. [20]

A major advantage of a day-ahead market structure, is that it helps generators plan their unit commitment more efficiently, particularly for less flexible stations, such as coal stations. The planning horizon for a day-ahead market provides adequate time to start up a slow unit, i.e. they are better able to coordinate their schedule between trading periods. Because of the day-ahead price signals, generators can determine whether or not it is cost-effective to commit a unit. A second advantage of day-ahead markets is an improved reliability due to generation being locked in one day ahead. The day-ahead market ensures sufficient generation is avaliable ahead of time and provides certainty to the generators, since they will know for how long they will have their units on [20].

Additionally, a day-ahead market provides extra certainty for the scheduling of interruptible load. A third advantage of a day-ahead market is the improved incentive for demand-side participation. Locking in generation ahead of time also hedges participants against the volatility of real-time prices. Because of this, electricity purchasers will be more willing to bid in the market. Due to the hedging against real-time prices, a day-ahead market will also protect participants against price uncertainty. In a real-time market, the generator may attempt to game the market by withholding generation. By reducing the amount of electricity sold on the real-time market, a day-ahead market may reduce the opportunities for gaming [20].

1.6.1 Overseas Markets

It is important to observe how day-ahead markets operate in overseas jurisdictions. The Nord Pool Spot market and the Colombian market are interesting to us because both of these markets have a large share of generation from hydropower, as in New Zealand.

1.6.1.1 Nord Pool

Nord Pool Spot runs an electricity market that serves the countries of Norway, Sweden, Finland, Denmark, Estonia, Latvia, and Lithuania and includes 370 market participants. The Nord Pool Spot market has both a day-ahead market and a market for trading close to real time, called an intraday market. The Nord Pool Spot market, like New Zealand, has a large share of hydropower. In 2011, hydroelectric generation accounted for 52.9% of the generation in the Nord Pool market and 57% of New Zealand's generation [9] [10]. Therefore, in any study that considers a day-ahead market in New Zealand, it is important to observe how the Nord Pool Spot market operates.

The majority of trading takes place on the day-ahead market, Elspot, which serves the Nordic and Baltic regions. Contracts are made between buyer and seller for the purchase of power on the following day. The price and quanitity for the contract is then agreed upon. The hourly system price is set by the intersection of the demand curve and the supply curve. This system price is used as a reference price for financial contracts. Hourly area prices are calculated if the inter-area flows exceed the transmission capacity. The day-ahead market has provisions for block bids, that is, offers that encompass multiple periods. A block bid can either be accepted or denied, i.e. there is no middle ground. Block bids complicate the optimisation by removing the problem's continuous nature by introducing binary variables [12].

Due to factors such as uncertain wind and demand or unforeseen outages, an intraday market is required to balance the market. The intraday market, Elbas, serves the Nordic and Baltic regions, as well as Germany. The intraday market is becoming increasingly important, as more wind generation is being introduced into the system. Like the Elspot market, the Elbas market prices may differ between areas. Cross-border trades on the intraday market reduce risk and provide traders with extra opportunities to make profit. The Elspot prices are separate to the Elbas prices, therefore the Nord

Pool Spot market is a two-settlement market [12].

In addition to the day-ahead and intraday markets, generation contracts are traded on a finanacial market. The system price calculated by the day-ahead transactions is used as the reference price for these contracts. These contracts are traded for the purpose of hedging against price volatility and managing risk [12].

1.6.1.2 Colombia

Colombia's electricity market is of interest to us because it has a similar mix of hydropower and thermal generation to New Zealand. Colombia's generation is dominated by hydroelectric power, with 67% of the country's installed capacity being hydropower. Gas, coal, and oil fuelled thermal plant make up 20%, 7%, and 3%, respectively. Colombia has massive potential for future development of hydroelectric generation, with an estimated 100 GW of untapped hydropower. Environmental constraints limit the pursuit of this potential hydro generation. The generators in Colombia's market are a mix of privately and publicly owned enterprises. The biggest three firms hold 55 percent of the market share. The Colombian electricity market has four components:

1. Day-ahead spot market, which sets the hourly spot prices and schedules the generation profile. Generators offer a marginal price and a generation quantity.

2. Generators and retailers are able to make bilateral contracts to hedge against spot prices.

3. Ancillary services market, which includes Automatic Generation Control and generator imbalances.

4. Firm energy market, which ensures sufficient reserves for the power system. This market provides payment for security of supply, separate from the generation payments. The firm energy market

pays participants in exchange for a commitment to provide energy if the spot price exceeds a "Scarcity Price". Therefore, the firm energy product is a financial call option backed by a physical resource. The inclusion of this payment provides an incentive for firm's to invest in cost-effective generation assets and has important risk-hedging implications for the market [30].

Unlike Nord Pool Spot, the Colombian market does not feature an intraday market. Instead, the market is balanced by energy sold through the firm energy market. Because the residual energy is balanced at a price separate to the day-ahead price, the Colombian market could be considered multisettlement.

1.7 Thesis Overview

The document layout is presented to improve the report's readability and aid the reader in understanding the report's structure. The remainder of the thesis is laid out as follows:

- In Chapter 2, we give a literature review, where we outline our research into similar studies and provide a context for this thesis.
- In Chapter 3, we describe the methodology. We begin by outlining our experiments. We then introduce the formulations that we have developed for our hydro scheme optimisation models. We then introduce the various market simulation models, demand estimation techniques that we use for our experiments, and the rationale behind these methodologies.
- In Chapter 4, we present the results from our experiments.
- In Chapter 5, we summarise our findings and make our concluding statements.
- Finally, in Chapter 6, we make recommendations for further course of action.

Chapter 2

Literature Review

2.1 Overview of Efficiency in Electricity Markets

The purpose of electricity markets is to produce electricity most efficiently. Typically, there are three key types of economic efficiency:

Productive Efficiency

Productive efficiency is maximized when the least amount of resources are consumed to produce a good or service. A firm that is productively efficient minimizes wastage, labour costs, and land costs and has the best available technology and production techniques [3]. In section 2.2, we discuss how firms may exercise their market power by producing more in off-peak periods and withholding generation in peak periods. This is productively inefficient, since stations with high marginal costs will be required to be run in the peak periods, whereas these stations would very rarely be required in off-peak periods. A more efficient practice is "peak-shaving", where stations with low marginal costs, such as hydro stations, are dispatched at a higher level in the peak periods and at a lower level during off-peak periods [19].

Allocative Efficiency

> Allocative efficiency is concerned with allocating resources in a way that maximizes the net benefit of consumers and producer. Allocative efficiency is achieved when resources are not wasted and the situation can not be improved for one participant without making it worse for another participant. In this case, the marginal production cost of the last unit produced is equal to its marginal benefit. Allocative inefficiencies may arise from such factors as pricing schemes, price caps, and lack of competition [34] [3].

Dynamic Efficiency

> Dynamic efficiency is concerned with making decisions that efficiently manage resources, technology, and investment over time [3].

2.2 Market Power and Hydroelectricity

Exercise of market power can be an important source of inefficiency in electricity markets. A firm that is exercising market power may restrict its output to a level where its marginal cost is significantly lower than the price, while smaller price-taking firms produce output at a marginal cost nearer to the price. In this situation, inefficient allocation of energy occurs across the market. More efficient allocation would result from the firm with market power increasing its production and the price-taking firms reducing their production. Because exercising market power raises the price above the system marginal cost, the primary measure of exercise of market power is the price-cost margin. The price-cost margin measures the difference between the price and the system marginal cost. In some industries, there is no publicly available data on the marginal costs for the producers. For example, the price-cost margin for hydro generators is not straightforward to calculate, since the cost of water itself is negligible. In order to estimate the marginal cost of water comsumption for hydro generators, the opportunity cost of water needs to be calculated. Water valuation will be discussed in further detail in section 2.3. In the absence of producers' marginal cost information, measures of market concentration, such as the Herfindahl-Hirschman Index (HHI) are used as an approximate measure of market power. The HHI is calculated by squaring the market share of each firm and summing the squared terms [37]. Market power is often correlated with market concentration and individual firm market share, but this is not always the case.

Market power is affected by many factors other than concentration and market share. One of these factors is the incentive for producers to exercise market power. For instance, a vertically integrated firm will have less incentive to exercise market power than a generation-only firm, since it may have to purchase more electricity than it generates. Another important factor is the elasticity of demand. If the consumption of a commodity does not vary much with prices, then there is opportunity for firms to exercise market power [18]. In the short run, price is very inelastic for electricity [17]. The potential for a firm's competitors to expand their production in response to the firm's restriction of output also reduces a firms ability to exercise market power. The competitors' ability to respond to a firm's reduction of output depends on the capacity of the competitors' stations as well as the capability of the local transmission network. [18].

Of particular interest to us is the potential for market power in electricity markets with a large share of hydroelectric generation. Firms with large hydroelectric capacity have a unique advantage in a deregulated market. Having the ability to shift energy production from one period to another gives strategic firms an opportunity to influence prices [19]. Reducing production is profitable for a firm if the increase in marginal price covers the loss in production [39]. For a hydroelectric generator, however, the withheld generation can be used at a later time. The ability to store energy for hydro generators is particularly important in electricity markets that have off-peak and peak periods. In the off-peak periods, prices are barely affected by dominant firms raising their production, since the production will only be replacing the production of smaller price-taking firms. However, in the peak periods, a dominant firm reducing its load will have a large impact on the price. Because of these price-response properties, there is incentive for firms operating hydro stations to increase their production in the off-peak periods and reduce their production in the peak periods.

Clearly, a system optimal solution would require the large firms to run their hydro stations more in the peak periods in order to "shave" the peaks. Therefore, this strategic behaviour is a departure from the optimal system-wide schedule. James Bushnell investigated the relationships between hydroelectric capacity and market power in the context of the Western United States electricity markets, particularly the California-Northwest region. At the time, hydro generation accounted for a significant share of the market capacity, and a significant share of this hydro generation was controlled by a single firm, the Bonneville Power Administration (BPA). Despite being a diverse market, with a high level of integration, it has been shown that there is potential for localized market power in this market [19].

Bushnell models the California-Northwest region (CNW), while assuming the surrounding regions, Canada, Rocky Mountains, and Southwest, are energy exporters. Within the CNW region, only the major Cailfornia firms are treated as strategic firms. As well as the BPA, South California Edison and Pacific Gas & Energy are treated as strategic firms. These three major firms are treated as Cournot players, while all other firms are treated as price-takers. These three firms account for 40% of the generation in the CNW region. Each of the Cournot players control both hydroelectric and thermal generation assets. This model neglects the effects of transmission losses and congestion within the CNW region, but the import of electricity is limited by line capacity. For the month of September in 2001, if the three major firms are behaving strategically, it was found that fringe firms were marginal only in off-peak periods.

BPA was found to allocate almost as much production to the off-peak periods as it did to the peak periods. In this case, there was a 10% decrease in hydro production during the peak periods, accounting for peak prices 112% higher than the perfectly competitive peak prices. When only BPA is acting strategically, prices are 80% higher than the perfectly competitive prices. It was found that the relatively dry Autumn months had the highest potential for exercise of market power. The ability of BPA to affect prices in the Spring months was less significant due to more water being available to all hydro generators, and due to the presence of high minimum flow constraints. Bushnell concludes that the bifurcation of electricity markets into peak and off-peak markets is driven by the limited water availability for price-taking firms. This bifurcation can also be exacerbated by transmission constraints, market regulation, and mixed incentives for firms. Additionally, Bushnell found that the effect of strategically shifting water between months was less noticeable than the strategic shifting of water within each month [19].

2.3 Coordination in Electricity Markets

In 1996, prior to the deregulation of the New Zealand electricity market and the consequent disbanding of the state-owned Electricity Corporation of New Zealand (ECNZ), Scott and Read [39] investigated the potential consequences of deregulation. At the time of the study, all the hydroelectric generation scheduling was managed centrally by the ECNZ. Firms in a deregulated market may have incentive to exercise market power to influence prices. This raised concerns that the results of "gaming" could outweigh the benefits of deregulation. The focus of Scott and Read's study was to quantify the efficiency loss resulting from loss of coordination and to compare this loss of efficiency to the economic benefits of deregulation [36] [39].

This study divides the assets between two major firms, as well as a fringe of minor firms, and models the major firms as a Cournot duopoly. The market structure for the deregulated market matches offers from each firm with a market demand function. There are two approximations for the demand functions, one that assumes constant elasticity, and one that assumes linear elasticity. The spot price is then determined by the intersection of the supply and demand curves. This study also models contracts between the generating firms and the consumers. These contracts include two way options, where firms sell a contracted quantity to the consumer at an agreed-upon price, and one way options which are effective when the spot price is above the contracted strike price. The presence of these contracts have the effect of reducing generators' incentives to exercise market power. For instance, if a firm is contracted for more generation than it can produce, it must buy energy from the spot market, in which case it has incentive to drive down the spot price.

The model for coordinating each generator's hydro and thermal assets is treated as a dynamic program, with a market model solved at each stage of the DP. The objective function for this model is nonlinear and potentially non-convex, because the spot price is a function of generation. Scott and Read model the value of water in two ways. The Demand Curve for Release (DCR) is a curve that represents the marginal value of water as a monotonic non-increasing function of hydro generation. In addition to the DCR, the Demand Curve for Storage (DCS) represents the marginal value of water as a function of reservoir storage at the end of each time period. Starting from a DCS for the end of the time horizon, a DCS for the previous period can be recursively calculated by adding the DCS at the end of the current period to the DCR for the current period.

The results from this study show that market power has little effect on the loss of coordination efficiency if, and only if, contracting is implemented to a high level or if elasticity is high. However, this study does not investigate the extent to which contracting would occur in the competitive market. The results in this study were very sensitive to demand elasticity, for instance the spot market distortion resulting from a demand elasticity of 0.1 and 90% contracting was comparable to that of 0.33 demand elasticity and 50% contracting [39].

Sioshansi, Oren, and O'Neill [41] studied the economic consequences of a centrally-committed day-ahead market structure based on three-part offers and compare this market design to an energy-only auction with self-commitment. This study examines the impact on pricing and efficiency for these market structures and examines the implications of each market structure for coordination efficiency loss and incentives for truthful bidding. In a decentralized market based on self-commitment, firms must respond to price signals and optimise their unit commitment and load dispatch in a feasible manner. Decentralized markets may suffer from inefficiency due to lack of spatial and dynamic coordination of resources, particularly in cases where transmission outages and generation unit outages are prevalent. The self-commitment model used in Sioshansi, Oren, and O'Neill's study, uses a simultaneous Walrasian-type day-ahead market, where the auctioneer iteratively adjusts prices and the participants respond to these prices by deciding which units to commit and offering the quantity that maximizes their profit for the provided energy price. The system operator continues to adjust the prices until the demand is met. In a centrally-committed market, firms provide the system operator with startup costs and running costs for each of their units, and the system operator optimises the unit commitment and load dispatch for the system.

While centralized markets do not suffer from loss of productive efficiency due to lack of coordination, problems associated with equity and cost misrepresentation incentives arise from a centralised market structure. The incentive issues mentioned in this paper refer to those outlined in Sioshansi and Nicholson's 2011 paper [40]. In the case of multi-part centralized markets, there is incentive to overstate the costs provided to the system operator. In order to compare the centrally committed and self-commitated markets, it is assumed that generators offer in the costs and constraint parameters given in the ISONE dataset. This assumes that participants would behave in the same manner under a centralized market with regard to representing their marginal costs and constraint parameters. This approach ignores the effect of price misrepresentation incentives for the centrally committed market, that is, it is assumed that the participants do not behave strategically. Therefore the comparison of the centrally-committed and self-committed markets is used to calculate the loss in productive efficiency resulting from self-commitment. In this case study, the self-commited market produced dispatch and commitment costs approximately 4% higher than the centrally-committed market [41].

2.4 Inefficiency in the New Zealand Electricity Market

Philpott and Guan [27] performed an empirical study that attempted to quantify the inefficiency in the New Zealand Wholesale Electricity Market. The study compares the historical market outcomes to the results from a centrally planned counterfactual model, spanning the years 2005 to 2009 [27]. Philpott and Guan present four deterministic central dispatch models, one stochastic central dispatch models, as well as optimisation models for approximating hydrological parameters and transmission network parameters. The most pertinent dispatch models developed are the Daily Central and Weekly Central models. The Daily and Weekly Central models are centrally planned dispatch models that are run over a 48 trading period horizon and a 336 trading period horizon respectively.

The dispatch models used by Philpott and Guan approximate New Zealand's 244 node transmisison network with an 20 node representation. This 20 node network is made up of 18 demand nodes and 1 node at either end of the inter-island HVDC link. This model ignores $N-1$ security, spinning reserve, and frequency keeping, meaning that it is likely to underestimate prices. Because of the condensed network, transmission losses between grid points within each of the major regions is ignored. This means that the aggregated total demand at each of the 18 demand nodes is underestimated. To compensate for this underestimation of demand, an optimisation model is solved to estimate scaling factors that result in the nodal demand being consistent with historical dispatch [27].

All cogeneration, geothermal, wind, and embedded generation are fixed to their historical dispatch levels. Additionally, all hydro generation outside of the Waitaki, Clutha, Manapouri, and Waikato schemes are fixed at historical levels. The remaining stations are allowed to offer into the market for the central models. These stations include the hydroelectric stations within the Waitaki, Clutha, and Manapouri schemes in New Zealand's South Island and the Waikato scheme in the North Island. The remaining offering stations are Huntly, New Plymouth, Stratford, Whirinaki, and Otahuhu, the major thermal plants. The cost for gas and diesel are assumed to be the quarterly values provided by the Ministry of Economic Development New Zealand and the cost of coal is assumed to be fixed across the years 2005 to 2009.

The short run marginal cost for thermal stations is calculated as the product of the heat rate and the fuel cost. Contracts and the effect of fuel shortages are ignored in the Central models. Derating of stations due to planned outages and derating of the transmission lines are included in all models. Thermal losses in the transmission lines are calculated as convex piecewise linear functions of transmission line flow [27]. The effect of unit commitment was found to be negligible for the Central Models, therefore unit commitment is ignored.

In order to compare the Central dispatch model with the historical dispatch, the boundary conditions need to be the same. However, using historical inflows, reservoir levels and generation from the Centralised Dataset (CDS), the reservoir levels do not perfectly match up with history. The discrepancies in reservoir levels are due to a number of factors. The inflows in the CDS are approximations of the true tributary inflow values and the inflow values are provided in the form of an average daily value. [27]. Because of delays in water transit times between a number of reservoirs, there are flows that are "in transit" at the beginning of each day. The reservoir levels in the CDS do not capture these flows in transit. Additionally, the historical levels for reservoirs in the CDS are only given for the beginning and end of each day and are only provided for particular lakes in each river chain. These lakes are Aviemore, Benmore, Hawea, Manapouri, Ohau, Pukaki, Taupo, Tekapo, Waitaki, and Ruataniwha.

A model, called Inter, is solved in order to estimate the hydrological boundary conditions for the centrally dispatched model. The boundary conditions estimated by the Inter model are the levels for lakes, reservoirs, and headponds, the flows in transit at the end of each day and the half-hourly tributary inflows. In order to attempt to capture the variation in turbine efficiency caused by changes in head levels and flow rates, the inter model allows the conversion factors to vary from one day to the next [26].

The Inter model assumes that the historical dispatch data from the CDS for the hydroelectric stations on the Waitaki and Waikato chains is the dispatch prior to rearranging the generation for the respective block dispatch groups. The Inter model performs a reallocation of this historical generation [27]. However, we now know that the generation data provided by Meridian in the CDS is the final generation, therefore this reallocation does not need to occur for the Waitaki Scheme [1]. The objective of the Inter model is to minimize the penalty cost on spilled water, deviation from historical reservoir levels, and violation of flow constraints. The terms in the objective function are weighted by factors that convert volume to energy, so as to represent the objective function in terms of a quantity that has a monetary value. In most cases, spill is penalized more heavily than deviation from historical reservoir volumes, in order to avoid spilling for the sake of matching historical levels. An exception to this high penalty on spill is made for the Manapouri scheme, where spill is likely due to high tributary inflows into Lake Manapouri [27].

The objective for the Central models is to minimize the sum of thermal fuel costs, load shedding costs, and flow bound violation penalty costs, penalty cost for spilling, and future cost. The future cost is set to be zero for the Daily and Weekly Central models [26].The Daily and Weekly Central models were run over the years 2005 to 2009. Fuel and load shedding costs for the Daily Central model were found to be 10% lower than the historical market outcome. On a yearly basis, the savings were 8.94%, 7.08%, 4.90%, 16.32%, and 12.65% for the years 2005 to 2009 respectively. For the Weekly Central

Model, the fuel and load shedding costs were found to be 13.56% lower than the historical market outcome and the yearly savings were 13.14%, 11.14%, 8.16%, 19.53%, and 15.73% respectively for the years 2005 to 2009. Philpott and Guan conclude that this inefficiency may stem from uncertainty, exercise of market power, and risk.

Now that we have provided a context for this study and introduced the factors that must be considered in modelling electricity systems, we can discuss the experimental methods of this study. The upcoming chapter begins with a thorough description of our experimental methods. We then introduce our hydro scheme optimisation models and provide a formulation of their constraints and objectives. Next, we introduce our market simulation models, explain the rationale behind each model, and explain how vSPD has been altered to accommodate these models. Finally, we will present the results from our experiments.

Chapter 3

Methodology

3.1 Experimental Description

We wish to identify the sources of inefficiency in New Zealand's electricity market and quantify the levels of inefficiency that can be attributed to each source. As mentioned earlier in the report, we wish to quantify these sources of inefficiency to assist in assessing whether or not a day-ahead market structure would benefit the NZEM. The loss of efficiency due to lack of coordination is of interest to us because day-ahead markets improve the coordination of the dispatch. Day-ahead markets improve coordination by providing pricing signals that assist generators with their unit commitment (especially thermal) and incent generators to offer the required generation. Day-ahead market transactions hedge participants against real-time prices, therefore loss of efficiency due to price/demand uncertainty is reduced in a day-ahead market. Therefore, it is important to quantify the loss of efficiency due to uncertainty in the NZEM. A day-ahead market structure will also reduce the opportunity for exercise of market power, so it is important to quantify the loss of efficiency due to market power in the NZEM [20]. The sources of efficiency loss that we wish to identify in our experiments are efficiency loss due to lack of coordination, uncertainty about future demands and prices, exercise of market power, and the loss of intertemporal coordination caused by a rolling dispatch mechanism.

We solve four optimization models aimed at isolating the sources of inefficiency. These models are as follows:

1. Unaltered vSPD model
2. Clairvoyant vSPD model (section 3.5.2.1)
3. Stack vSPD model (section 3.5.2.2)
4. Rolling Central vSPD model (section 3.5.2.3)

We use vSPD as the framework for our models, since it provides a full-scale representation of the New Zealand transmission network, and includes market security constraints, and provides the opportunity to include reserve. However, for simplicity, we ignore reserve offering and dispatch in our market simulation models. We also ignore the effects of unit commitment for both hydro generators and thermal generators, in our experiments. If we were to model the unit commitment, we would need to model the problem as a mixed integer program (MIP). A MIP model might be tractable in reasonable time for optimising each individual agent's profit. However, incorporating unit commitment into the Stack vSPD model or the Clairvoyant vSPD model would not be computationally viable at this stage, particularly for the latter case. Instead of modelling unit commitment, we look at the total cost of fuel consumption and cost of constraint violation over the experimental days, and estimate the inefficiencies in the market by calculating how much money could be saved by changing the market structure.

We model the marginal thermal cost function as a constant cost, which is calculated as the product of the heat rate and the seasonal cost of fuel. We take the real wholesale price of diesel and gas, in

2013 dollars, from the fuel price data tables on the *med.govt.nz* website [33]. We do not model issues surrounding the procurement of fuel, such as take-or-pay contracts, as this would result in a more complex model than is necessary for this study. We assume the real price of coal does not change over the years that we are looking at. We assume the real price is $4 /GJ in 2008 dollars [26], and we convert this value to the real cost in 2013 dollars, $4.36. Our assumption of a constant real price of coal is due to coal being stored in large stockpiles. A more involved model might include the costs of restocking the stockpile. For simplicity, we do not model coal stockpile effects in this study.

The data in our experiments comes from a variety of sources. Our heat rate data comes from the Ministry of Economic Development, Covec, and Philpott and Guan's Modelling Summary [16][26][21]. For the source of our hydrology data, refer to section 3.2.1. All of our demand data comes from the vSPD GDX files. The pricing data used for building distributions and making initial pricing estimates for our stack model come from the CDS.

This experiment is performed using data between the years 2008 and 2009. Therefore, our models do not include the transfer of ownership from Meridian to Genesis for the Tekapo A and Tekapo B stations, occuring in 2011. In addition, the GDX files used by vSPD contain station and lines capacities, subject to de-rating, for each trading period.

3.1.1 Unaltered vSPD Model

By solving the unaltered version of vSPD with historical offers and demand, including reserve, we obtain the historical generation for the day of interest. We use the historical information for two purposes: calculating the fuel and constraint violation costs in the historical solution and finding the historical levels for non-offering generators, which will be offered in at zero price for our market simulation models. After solving the unaltered vSPD with historical data, we then alter the offer prices for the offering thermal stations to be equal to their fuel cost plus operations and maintenance cost, and set the offer prices for all other generators to be equal to zero. We then calculate the short-run cost of the historical solution with these updated offer prices, in order to produce a short-run cost that is comparable to our market simulation solutions. In order to get prices that can be compared with our market simulation models, we take the historical generation of each station, and offer in these quantities at the updated offer prices, i.e. using the same fuel costs as our market simulation solutions.

3.1.2 Clairvoyant vSPD Model

This model assumes perfect information about demand and inflows throughout the day, and assumes a centrally-coordinated plan of the entire electricity system. For "non-offering" generators, generation is set at its historical value, as calculated by vSPD. The marginal cost for hydro generators is assumed to be zero, and the marginal cost for thermal generators is calculated as its marginal fuel cost plus the marginal operations and maintenance costs for each station. We choose to implement a water value term in the objective function for all our market simulation models. We solve the clairvoyant solution iteratively until we find penalties (or savings incentives) that are large enough to prevent deviation from target reservoir volumes and end of day in-transit flows. For a step-by-step description of this process, see section 3.5.2.1. The final solution to this problem is an equilibrium under perfect competition, given the reward coefficients for water savings, and the cost coefficients for water over-expenditure for each reservoir. The optimal generation from the Clairvoyant model is then offered into an altered vSPD model, in order to produce prices that are comparable with our other market simulation models. Comparing the Clairvoyant model with the historical solution provides us with an estimate of the total inefficiency in the market, as compared with a clairvoyant social planning solution [27].

3.1.3 Stack vSPD Model

This model assumes perfect information about inflows, but not about demand. Unlike the Clairvoyant model, the planning of the hydroelectric schedules is not centrally-coordinated i.e. each agent optimizes their own river, given a vector of projected future prices. The Stack vSPD model also differs from the Clairvoyant Model in the way that it is solved iteratively, instead of being solved in one shot. Therefore, the amount of money saved by the Clairvoyant solution, compared with the Stack vSPD model, provides us with an estimate of efficiency loss caused by lack of coordination of generation, uncertainty about future demand and prices, and the rolling dispatch mechanism.

Comparing the Stack vSPD model with the historical dispatch provides us with an estimate of the remaining source of inefficiency, which is an upper bound on exercise of market power. This figure may also include the effects of risk and reserve, which we do not include in our models. This comparison assumes that the Stack vSPD model has a similar level of uncertainty to the actual market. This model uses the water penalty coefficients calculated by the Clairvoyant model to value water being above/below target reservoir levels and end of day in-transit flows at the end of the day. Thermal stations offer their total capacity, minus derating, at the same offer price as the Clairvoyant solution, while hydro stations offer in a multi-tranche stack at non-zero prices (see section 3.5.2.2 for detailed information on this). The prices produced directly from the Stack vSPD model, will not be directly comparable with those produced by our other models, since the stacks for hydroelectric stations are offered in at non-zero prices. Therefore, after we have found the optimal solution for the Stack vSPD model, we offer the optimal generation quantities into the vSPDR model, with the price of hydro generation set to zero, and the price of thermal generation unchanged.

3.1.4 Rolling Central Model

This model assumes perfect information about inflows, but not about demand. In a similar manner to the Stack vSPD model, the Rolling Central model is a rolling dispatch model. In contrast to the Stack vSPD model, this is a centrally coordinated model. Therefore, when we compare this model to the Stack vSPD model, we can estimate the loss of efficiency caused by having a dispatch mechanism that is not coordinated between the agents. This estimation can be loosely compared to Sioshansi and Oren's estimates of inefficiency due to loss of coordination. In their study they examined the effect of losing coordination of the daily unit commitment, whereas we examine the effect of losing coordination of river chain management.

Comparing the Rolling Central Model to the Clairvoyant model provides us with an estimate of the loss of efficiency due to uncertainty in demand. As with the Stack vSPD model, the Rolling Central uses the water cost coefficients calculated by the Clairvoyant solution and the historical generation for non-offering generators calculated by the historical vSPD solution. The marginal cost of hydro and thermal stations is the same as those used in the Clairvoyant model. In order to produce prices comparable to our other solutions, we take the optimal solution from Rolling Central and offer into vSPDR, without altering the offer price.

The Historical, Clairvoyant, and Stack vSPD models are solved over approximately one year of data. However, due to time constraints, we solve the Rolling Central model over two months.

To summarise, the types of inefficiency identified by our experiments are plotted in Figure 3.1.4.

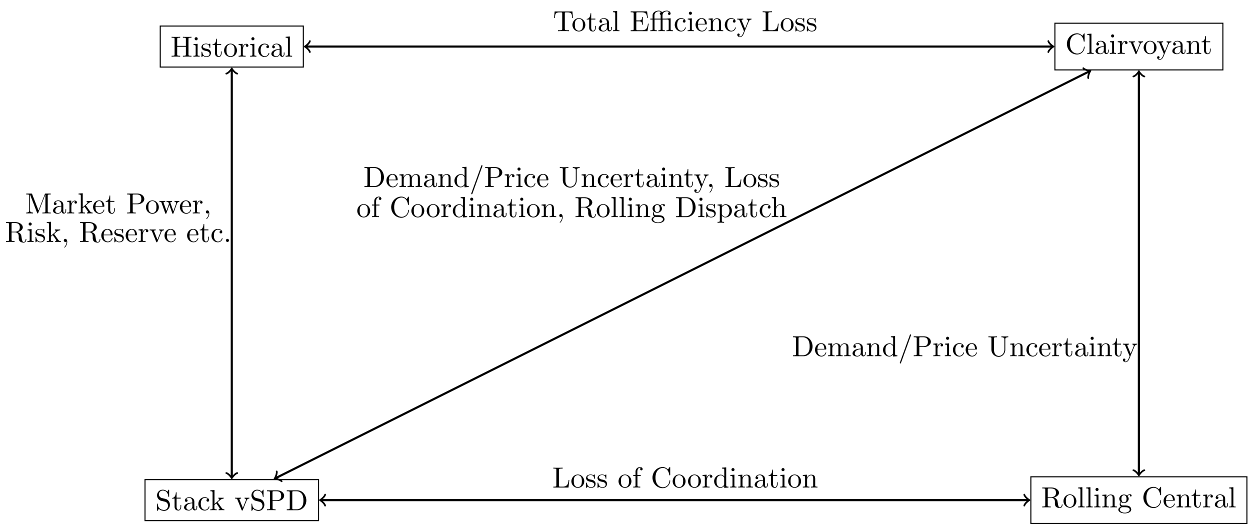

Figure 3.1: Types of Inefficiency Identified by Comparing Models

3.2 Modelling and Formulation

3.2.1 River Chain Model

Hydropower accounts for approximately 57% of New Zealand's generation [9]. Therefore, in order to perform our experiments, we need to develop a model for the running of New Zealand's hydropower schemes. We call this model the River Chain Model. The River Chain Model is a general formulation that can be applied to the major hydrolelectric schemes in New Zealand. For our experiments we apply the River Chain Model to the Waikato, Waitaki, Clutha, and Manapouri schemes. The river chain formulation can stand alone, being optimised with respect to expected electricity prices, or it can be integrated with a Scheduling, Pricing, and Dispatch model, such as vSPD, in order to centrally plan the nation's generation with respect to hydrological constraints. For more information on the centrally planned solution, refer to section 3.5.2.1.

3.2.1.1 Modelling Assumptions

3.2.1.1.1 Formulation Assumptions

For simplicity, we model the river nodes, i.e. stations, junctions, and reservoirs, under a single set H. Where possible, we model a station/reservoir pair as a single network node. For instance, we do not differentiate between Lake Manapouri and Manapouri Station; we model it as a single network node. However, some lakes, such as Taupo do not have a generating station directly following it. Other lakes are directly followed by a station, but are not the only lake feeding that station. For example, Ohau and Pukaki both feed the Ohau A hydro station. In the case of these lakes that are not uniquely associated with a station, we set the upper bound on generation to zero. For hydro stations that are not uniquely associated with a lake, we set the upper bound on storage to be zero.

We also model junctions, which are nodes in the river network which have have input and output flows, but do not have any storage. For junctions, we set the upper bound on storage to be zero and the upper bound on generation to be zero. This means that flow entering a junction at a particular trading period must equal the flow leaving the junction at that trading period. We discretise the planning horizon into 48 trading periods contained in set T. The reservoir storage variables for a trading period represent the volume at the end of each trading period for each reservoir.

3.2.1.1.2 Physical Modelling

In our experiments, we assume a linear production function for hydro generating units. In earlier experiments, we modelled the power output as convex quadratic functions of generating flow. Nonlinear functions were not suitable for full-scale experiments with the centrally coordinated model, therefore we chose to assume linear production functions. Additionally, we do not model the effect of reservoir levels on marginal power output. If we were to model head effects, we would need to introduce either integer or nonlinear variables. These would not be able to implemented on a large scale, so we ignore the head effects.

Another common modelling feature that we choose to ignore is the unit commitment. Modelling the unit commitment would require the introduction of integer variables, making the problem intractable on a large scale. The base conversion factor values that we use are provided in the modelling summary for Philpott and Guan's models [26]. We let these conversion factors vary on a day-to-day basis. The calculation of the daily conversion factor values is explained in section 3.2.2. Section 3.2.2 also details the calculation of the hydrological boundary conditions for our experiments.

Our model covers all the basic hydrological functions of a hydroelectric river chain. Certain stations have the ability to spill water around the station's generator. The River Chain Model does not place a penalty cost on spilling water. However, the opportunity cost incurred by spilling instead of generating is implicitly factored into the River Chain Model. All lakes and head ponds have consented minimum and maximum operating water levels. We model these reservoir limits as hard bounds on the reservoir volumes. We model minimum and maximum flows along some flow arcs in our model. The minimum and maximum flow rates we model may be non-generating flow rates only or the sum of generating flow and non-generating flow from a station. We do not model limits on generating flow only, since this is implicitly modelled in the maximum generation for a station. We model a minimum total flow from Lake Dunstan to the Roxburgh head pond that is only observed during night-time trading periods. The night-time periods are between TP 38 and TP 10.

The River Chain Model has a target reservoir level for each lake l for the end of the planning horizon. We allow the final reservoir levels to vary from these target reservoir levels. Exceeding the target reservoir levels may incur either a penalty or a bonus, while a shortfall on reservoir volume will incur a penalty.

For simplicity, we ignore reserve offering and frequency keeping in our River Chain Model. We do this because we do not have time to develop a realistic model for offering reserve. In future works, it may be useful to develop models that include reserve.

In practice, there is a transit time between water being released from an upstream reservoir and arriving at the downstream reservoir. We include this time delay in our models. For reaches where the flow delay time is sufficiently small, we assume that the water arrives downstream instantaneously. Because of these flow transit times, we have flows that are "in transit" between days. We model in-transit flows arriving in early periods of the day as fixed inflows. We also have target in-transit flows at the end of the day. The target is a total volume in-transit en route to each hydrological node $h \in H$. These in-transit flows are calculated by the hydrological boundary condition model outlined in section 3.2.2. In a similar manner to the target reservoir volumes, we allow the flows in transit at the end of the planning horizon to vary from their targeted levels. Exceeding the total volume of in-transit flow may incur either a penalty or a bonus, while a shortfall on volume in-transit will incur a penalty.

A number of lakes have uncontrolled tributary flows. For our experiments we assume that the tributary flows are known throughout the day. The Centralised Dataset (CDS) provides average daily inflows. Our hydrological boundary condition model in section 3.2.2 outlines how we estimate the half-hourly tributary inflows for our experiments.

The EMBER dataset, summarised in Philpott and Guan's modelling summary [26] provides us with data for flow delays, upper and lower bounds on flow arcs, and capacities for reservoirs and head ponds. The capacity for head ponds, such as Ohau C and Tekapo B, are only rough estimates of their true values, while the capacities for the major lakes are estimated with a much higher precision.

3.2.1.2 River Chain Model Formulation

3.2.1.2.1 Sets and Mapping used in Formulation

- T the set of time periods
- T^N the set of night-time periods
- H the set of all river network nodes: Hydro Stations, Reservoirs and Junctions
- L the subset of H for Reservoirs only
- S^H the set of Hydro Stations in vSPD
- N the set of transmission nodes
- S the set of all stations in vSPD
- K is the set of hydro generation contracts
- Z is the set of vSPD market node constraints relating to generation
- C the set of River Chains
- A the set of River Chains with block dispatch
- N^h a single transmission node corresponding to river node $h \in H$
- H^C the set of all stations, reservoirs, and junctions corresponding to river chain $c \in C$
- $SH(s,h)$ is the mapping of station $s \in S$ to its corresponding river node $h \in H$
- $\overline{\Omega}(\hat{h},\check{h})$ defines the spill arcs from river node $\hat{h} \in H$ to river node $\check{h} \in H$
- $\Omega(\hat{h},\check{h})$ defines generating flow arcs from river node $\hat{h} \in H$ to river node $\check{h} \in H$

3.2.1.2.2 Variables used in River Chain Formulation

- $X_{s,t}$ is the generation of station $s \in S$ at trading period $t \in T$
- $\overline{X}_{h,t}$ is the generation of river node $h \in H$ at trading period $t \in T$. This is fixed at zero for junctions and lakes without generation.
- $\tilde{X}_{h,k,t}$ is the contribution of river node node $h \in H$ to hydro generation contract $k \in K$ during trading period $t \in T$
- $X^{\Sigma}_{c,t}$ is the sum of generation at river chain $c \in C$ for time period $t \in T$. When fixed, this variable enforces the block dispatch constraint.
- $\widehat{\delta}_l$ is the surplus above the target reservoir volume, in m^3, for each reservoir $l \in L$
- $\check{\delta}_l$ is the deficit below the target reservoir volume, in m^3, for each reservoir $l \in L$
- $\widehat{\delta}^{\omega}_h$ is the surplus, in m^3, above the target end of day volume in-transit destined for each river node $h \in H$
- $\check{\delta}^{\omega}_h$ is the deficit, in m^3, below the target end of day volume in-transit destined for each river node $h \in H$
- $\widehat{\delta}^{R}_{h,t}$ is the amount by which the upper-bound for ramping is exceeded for river node $h \in H$ at trading period $t \in T$
- $\check{\delta}^{R}_{h,t}$ is the amount by which the lower-bound for ramping is violated for river node $h \in H$ at trading period $t \in T$
- $\widehat{\delta}^{Z}_{z,t}$ is the the amount by which the upper-bound for the market node constraint is exceeded for constraint $z \in Z$ at trading period $t \in T$

- $\breve{\delta}^{Z}_{z,t}$ is the amount by which the lower bound for the market node constraint is violated for constraint $z \in Z$ at trading period $t \in T$

- $\widehat{\omega}_{\hat{h},\check{h},t}$ is the generating flow leaving from river node $\hat{h} \in H$, en route to station $\check{h}, \in H$ at trading period $t \in T$

- $\breve{\omega}_{\hat{h},\check{h},t}$ is the generating flow arriving from river node $\hat{h} \in H$, at river node $\check{h} \in H$ trading period $t \in T$

- $\overline{\omega}_{\hat{h},\check{h},t}$ is the non-generating flow arriving from $\hat{h} \in H$ at river node $\check{h} \in H$ at trading period $t \in T$

- $\omega_{\hat{h},\check{h},t}$ is the non-generating flow leaving from river node $\hat{h} \in H$ en route to river node $\check{h} \in H$ at trading period $t \in T$

- $Y_{h,t}$ is the reservoir volume, in m^3, at river node $h \in H$ at the end of trading period $t \in T$. This is non-zero only for reservoirs.

- $\breve{Y}_{h,t}$ is the volume of flow received, in m^3, by river node $h \in H$ at trading period $t \in T$

- $\widehat{Y}_{h,t}$ is the volume of flow, in m^3, leaving river node $h \in H$ at trading period $t \in T$

3.2.1.2.3 Parameters used in River Chain Formulation

- $U^{x}_{h,t}$ is the maximum generation at river node h $\in H$ at trading period $t \in T$, subject to half-hourly derating

- U^{y}_{h} is the maximum reservoir volume at river node $h \in H$

- $U^{\omega}_{\hat{h},\check{h}}$ is the maximum nongenerating flow at river node h $\in H$

- $U^{\check{y}}_{h}$ is the minimum total flow arriving at river node h $\in H$

- $U_h^{\hat{y}}$ is the maximum total flow leaving river node h $\in H$
- $\lambda_h^{\hat{y}}$ is the minimum total flow leaving river node $h \in H$
- $\overline{\lambda}_h^{\hat{y}}$ is the minimum total flow leaving river node $h \in H$ during the night-time period
- $\lambda_{\hat{h},\check{h}}^{\omega}$ is the minimum nongenerating flow from river node $\hat{h} \in H$ to river node $\check{h} \in H$
- Y_h^0 is the initial volume of river node $h \in H$
- Y_h^T is the target end of day volume of river node $h \in H$
- ω_h^T is the target end of day volume of flows in-transit destined for river node $h \in H$
- γ_l is the cost coefficient corresponding to having a shortage of water relative to target reservoir levels for each reservoir $l \in L$
- β_l is the cost coefficient corresponding to exceeding target reservoir levels for each reservoir $l \in L$
- γ_h^{ω} is the cost coefficient corresponding to having a shortage of water relative to target end of day in-transit flows for each river node $h \in H$
- β_h^{ω} is the cost coefficient corresponding to exceeding target end of day in-transit flows for each river node $h \in H$
- η_h is the conversion factor for river node $h \in H$, in MW/m^3 s^{-1}
- $\hat{\tau}$ is the number of hours in a trading period, which is always 0.5 in our experiments
- $\overline{\tau}$ is the number of seconds in an hour, 3600.
- $\overline{X}_h^0$ is the initial generation at river node $h \in H$

- $\check{X}_{ht}$ is the maximum amount, in MW/h that river node $h \in H$ can be ramped down in period $t \in T$

- $\widehat{X}_{ht}$ is the maximum amount, in MW/h that river node $h \in H$ can be ramped up in period $t \in T$

- $\check{I}_{h,t}$ is the inflow, in m^3, at river node $h \in H$ at trading period $t \in T$

- $\Delta_{\hat{h},\check{h}}$ is the flow delay time between river node $\hat{h} \in H$ and $\check{h} \in H$

- $\widehat{I}_{h,t}$ is the flow in-transit, in m^3, from the previous day at river node $h \in H$ arriving during trading period $t \in T$

- $\kappa_{h,k}$ is the contribution factor of river node $h \in H$ to hydro generation contract $k \in K$. $\kappa_{h,k}$ will be 1 if the contract k is being sold at the same node as river node h, 0 if river node h cannot contribute to contract k, or between 0 and 1 if the hydro generation is purchased at a different node to the contract.

- $\overline{K}_{k,t}$ is the amount of generation, in MW, required for contract $k \in K$ at trading period $t \in T$

- $\zeta_{s,z,t}$ is the the factor allocating station $s \in S$ to Market Node constraint $z \in Z$ for each trading period $t \in T$

- $\lambda^Z_{z,t}$ is the lower limit on generation corresponding to Market Node constraint $z \in Z$ for each trading period $t \in T$

- $U^Z_{z,t}$ is the upper limit on generation corresponding to Market Node constraint $z \in Z$ for each trading period $t \in T$

- c^R the cost penalty, in $\$/MW$ for violating ramping constraints

- c^Z the cost penalty, in $\$/MW$ for violating market node generation constraints

3.2.1.2.4 General River Chain Objective Function

$$max \sum^{h\in H} \sum^{t\in T} \Big(P_{N^h,t}(\overline{X}_{h,t} - \sum^{k\in K} \tilde{X}_{h,k,t}) - c^R(\widehat{\delta}^R_{h,t} + \check{\delta}^R_{h,t})\Big) + \sum^{l\in L}(\beta_l\widehat{\delta}_l - \gamma_l\check{\delta}_l) + \sum^{h\in H}(\beta^\omega_h\widehat{\delta}^\omega_h - \gamma^\omega_h\check{\delta}^\omega_h)$$

The objective function for the general river chain problem is to maximize the revenue of generated electricity minus the penalty cost for violating ramping constraints and future cost of water left in reservoirs and in transit. The revenue is calculated as the net generation at each node $n \in N$, that is, total generation minus any contracted generation, multiplied by the expected nodal electricity price, summed across all time periods. The violation on ramping is calculated from the slack and surplus variables on constraints 6.1. to 6.4. in the formulation below. The slack and surplus variables on constraints 3 and 4 are used to calculate the cost incurred (or money saved) by not meeting the final reservoir levels and in-transit targets, respectively.

3.2.1.2.5 vSPD River Chain Objective

$$max \sum^{l\in L}(\beta_l\widehat{\delta}_l - \gamma_l\check{\delta}_l) + \sum^{h\in H}(\beta^\omega_h\widehat{\delta}^\omega_h - \gamma^\omega_h\check{\delta}^\omega_h) + \sum^{h\in H} \sum^{t\in T} \Big(P_{N^h,t}(\overline{X}_{h,t} - \sum^{k\in K} \tilde{X}_{h,k,t}) - c^R(\widehat{\delta}^R_{h,t} + \check{\delta}^R_{h,t})\Big)$$
$$- \sum^{z\in Z} \sum^{t\in T} \Big(c^z(\widehat{\delta}^Z_{z,t} + \check{\delta}^Z_{z,t})\Big)$$

The objective function for the general river chain problem is to maximize the revenue of generated electricity minus the penalty cost for violating ramping constraints, market node constraints and future cost of water left in reservoirs. The only way this objective function varies from the objective function for the general river chain formulation is the penalty term for the vSPD market node generation constraints. The slack and surplus variables for the market node constraints are calculated in constraints 11.1. and 11.2.

3.2.1.2.6 General River Constraints

1. $\overline{X}_{h,t} = \sum^{\check{h}\in\Omega(h,\check{h})} \eta_h \widehat{\omega}_{h,\check{h},t}$ $\quad \forall h \in H, \forall t \in T$

2. Flow Delay Constraints

   2.1. $\overline{\omega}_{\hat{h},\check{h},t} = \omega_{\hat{h},\check{h},t-\Delta_{\hat{h},\check{h}}}$ $\quad \forall \hat{h}, \check{h} \in \overline{\Omega}(\hat{h},\check{h}), \forall t > \Delta_{\hat{h},\check{h}} \in T$

   2.2. $\check{\omega}_{\hat{h},\check{h},t} = \widehat{\omega}_{\hat{h},\check{h},t-\Delta_{\hat{h},\check{h}}}$ $\quad \forall \hat{h}, \check{h} \in \Omega(\hat{h},\check{h}), \forall t > \Delta_{\hat{h},\check{h}} \in T$

   2.3. $\check{Y}_{h,t} = \hat{\tau}\overline{\tau} \left(\sum^{\hat{h}\in\overline{\Omega}(\hat{h},h)} \overline{\omega}_{\hat{h},h,t} + \sum^{\hat{h}\in\Omega(\hat{h},h)} \check{\omega}_{\hat{h},h,t} \right)$ $\quad \forall h \in H, \forall t \in T$

   2.4. $\widehat{Y}_{h,t} = \hat{\tau}\overline{\tau} \left(\sum^{\check{h}\in\overline{\Omega}(h,\check{h})} \omega_{h,\check{h},t} + \sum^{\check{h}\in\Omega(h,\check{h})} \widehat{\omega}_{h,\check{h},t} \right)$ $\quad \forall h \in H, \forall t \in T$

3. $Y_{l,t} = Y_l^T + \widehat{\delta}_l - \check{\delta}_l$ $\quad \forall l \in L, t = |T|$

4. $\sum^{\hat{h}\in\overline{\Omega}(\hat{h},h)} \sum^{t\in\{T:t+\Delta_{\hat{h},h}>|T|\}} \widehat{Y}_{\hat{h},t} = \omega_h^T + \widehat{\delta}_h^{\omega} - \check{\delta}_h^{\omega}$ $\quad \forall h \in H$

5. Conservation of Mass Constraints

   5.1. $Y_{h,t} = Y_{h,t-1} + \check{Y}_{h,t} - \widehat{Y}_{h,t} + \check{I}_{h,t} + \widehat{I}_{h,t}$ $\quad \setminus \{1\}, \forall h \in H$

   5.2. $Y_{h,t} = Y_h^0 + \check{Y}_{h,t} - \widehat{Y}_{h,t} + \check{I}_{h,t} + \widehat{I}_{h,t}$ $\quad t = 1, \forall h \in H$

6. Ramp Constraints

   6.1. $\overline{X}_{h,t} \geq \overline{X}_{h,t-1} - \check{\delta}_{h,t}^R - \hat{\tau}\check{X}_{h,t}$ $\quad \forall t > 1 \in T, \forall h \in H$

   6.2. $\overline{X}_{h,t} \leq \overline{X}_{h,t-1} + \widehat{\delta}_{h,t}^R + \hat{\tau}\widehat{X}_{h,t}$ $\quad \forall t > 1 \in T, \forall h \in H$

   6.3. $\overline{X}_{h,t} \geq \overline{X}_h^0 - \check{\delta}_{h,t}^R - \hat{\tau}\check{X}_{h,t}$ $\quad t = 1, \forall h \in H$

   6.4. $\overline{X}_{h,t} \leq \overline{X}_h^0 + \widehat{\delta}_{h,t}^R + \hat{\tau}\widehat{X}_{h,t}$ $\quad t = 01, \forall h \in H$

7. Variable Upper and Lower Bounds

   7.1. $\overline{X}_{h,t} \leq U_{h,t}^x$ $\quad \forall h \in H, \forall t \in T$

7.2. $Y_{h,t} \leq U^{y}_{h}$ $\forall h \in H, \forall t \in T$

7.3. $\omega_{\hat{h},\check{h},t} \leq U^{\omega}_{\hat{h},\check{h}}$ $\forall \hat{h}, \check{h} \in H, \forall t \in T$

7.4. $\check{Y}_{h,t} \leq U^{\check{y}}_{h}$ $\forall h \in H, \forall t \in T$

7.5. $\hat{Y}_{h,t} \leq U^{\hat{y}}_{h}$ $\forall h \in H, \forall t \in T$

7.6. $\hat{Y}_{h,t} \geq \lambda^{\hat{y}}_{h}$ $\forall h \in H, \forall t \in T$

7.7. $\hat{Y}_{h,t} \geq \overline{\lambda}^{\hat{y}}_{h}$ $\forall h \in H, \forall t \in T^{N}$

7.8. $\omega_{\hat{h},\check{h},t} \geq \lambda^{\omega}_{\hat{h},\check{h}}$ $\forall \hat{h}, \check{h} \in H, \forall t \in T$

7.9. All vars ≥ 0

8. $X^{\Sigma}_{c,t} = \sum^{h \in H^{c}} \overline{X}_{h,t}$ $\forall c \in A, \forall t \in T$

9. Contract Constraints

9.1. $\sum^{h \in H} \kappa_{h,k} \tilde{X}_{h,k,t} = \overline{K}_{k,t}$ $\forall k \in K, \forall t \in T$

9.2. $\overline{X}_{h,t} \geq \sum^{k \in K} \tilde{X}_{h,k,t}$ $\forall h \in H, \forall t \in T$

3.2.1.2.7 vSPD Integration Constraints

10. $\overline{X}_{h,t} = \sum^{s \in SH(s,h)} X_{s,t}$ $\forall h \in H, \forall t \in T$

11. vSPD Market Node Generation Constraints

11.1. $\sum^{s \in S} \zeta_{s,z,t} X_{s,t} \leq U^{Z}_{z,t} + \widehat{\delta}^{Z}_{z,t}$ $\forall z \in Z, \forall t \in T$

11.2. $\sum^{s \in S} \zeta_{s,z,t} X_{s,t} \geq \lambda^{Z}_{z,t} - \check{\delta}^{Z}_{z,t}$ $\forall z \in Z, \forall t \in T$

3.2.1.2.8 River Chain Constraint Description

Constraint 1

This constraint defines the total turbine flow for river node $h \in H$ during trading period $t \in T$. This is assumed to be linear with respect to MW output and constant with respect to reservoir volume.

Constraint 2

These constraints model the intertemporal delay between flow leaving river node $\hat{h}$ at trading period t and arriving at river node $\check{h}$ at trading period $t + \Delta_{\hat{h},\check{h}}$.

2.1. This constraint equates the flow arriving at river node $\check{h}$ at trading period t with the flow leaving river node $\hat{h}$ at trading period $t - \Delta_{\hat{h},\check{h}}$. this constraint is defined over all trading periods later than $\Delta_{\hat{h},\check{h}}$ and over all defined pairings of $\hat{h}$ and $\check{h}$. For all periods less than $\Delta_{\hat{h},\check{h}}$, we have in-transit flows from the previous day. These in-transit flows are included in constraint 5

2.2. This constraint equates the generating flow arriving at river node $\check{h}$ at trading period t with the flow leaving river node $\hat{h}$ at trading period $t - \Delta_{\hat{h},\check{h}}$. this constraint is defined over all trading period later than $\Delta_{\hat{h},\check{h}}$ and over all defined pairings of $\hat{h}$ and $\check{h}$. For all periods less than $\Delta_{\hat{h},\check{h}}$, we have in-transit flows from the previous day. These in-transit flows are included in constraint 5

2.3. This constraint calculates the flow received, in m^3 by each river node h at trading period t. This flow excludes tributary inflows and flows in-transit from the previous day.

2.4. This constraint calculates the flow sent, in m^3 by each river node h at trading period t. This flow excludes tributary inflows and flows in-transit from the previous day.

Constraint 3

The final reservoir volume constraint sets a target level for each reservoir l to meet for the final trading period of the day. Slack and surplus variables allow the reservoir levels to vary above or below the target levels. However, penalty terms in the objective function either incent or penalize not meeting the target level.

Constraint 4

The end of day in-transit volume constraint sets a target level for each river node h to meet at the end of the day. That is, there is a total volume of flow in-transit that is planned to enter each reservoir, station, or junction that has a delay 1 TP or greater. Slack and surplus variables allow the volume in-transit to vary above or below the target levels. However, penalty terms in the objective function either incent or penalize not meeting the target level.

Constraint 5

5.1. Conservation of mass constraint defined for all periods later than TP1. The conservation of mass constraint calculates the reservoir volume for each river node h at each trading period t, by subtracting all outflows and adding all inflows from the reservoir level at trading period $t-1$. Tributary inflows, in-transit flows, and incoming controlled flows from other stations, reservoirs, and junctions are added to the reservoir, and all outgoing controlled flows are subtracted from the reservoir.

5.2. Conservation of mass constraint defined for the first trading period. The conservation of mass constraint calculates the reservoir volume for each river node h for TP1, by subtracting all outflows and adding all inflows to the initial reservoir level. Tributary inflows, in-transit flows, and incoming controlled flows from other stations, reservoirs, and junctions are added to the reservoir, and all outgoing controlled flows are subtracted from the reservoir.

Constraint 6

These constraints model the limits on ramping for each of the hydro stations.

6.1. This constraint models the soft lower bound on generation imposed by ramping limits for all trading periods later than TP1. We allow this bound to broken, but we penalize all generation below the lower ramping limit.

6.2. This constraint models the soft upper bound on generation imposed by ramping limits for all trading periods later than TP1. We allow this bound to broken, but we penalize all generation above the upper ramping limit.

6.3. This constraint models the soft lower bound on generation imposed by ramping limits for the first trading period. We allow this bound to broken, but we penalize all generation below the lower ramping limit. Unlike constraint 6.1., the generation from the previous is a fixed parameter equal to the historical generation at each station.

6.4. This constraint models the soft upper bound on generation imposed by ramping limits for the first trading period. We allow this bound to broken, but we penalize all generation above the upper ramping limit. Unlike constraint 6.2., the generation from the previous is a fixed parameter equal to the historical generation at each station.

Constraint 7

These constraints provide upper and lower bounds for each of the variables in the river chain problem.

7.1. Each station has an upper bound on its generation. This may be subject to generator derating. In our vSPD models outlined in section 3.5, the max generation in each station is subject to half-hourly capacities minus derating provided by the daily GDX files. This will be set to zero for all junctions and for lakes that are not paired with a generating station.

7.2. This constraint defines the upper bound on reservoir volume for each river node $h \in H$ at trading period $t \in T$. For all junctions and for all stations not paired with a lake, this upper bound is set to zero.

7.3. This constraint sets the upper bound on non-generating flow between river nodes $\hat{h} \in H$ and $\check{h} \in H$ at trading period $t \in T$. This constraint is defined for all valid pairs of $\hat{h}$ and $\check{h}$ and over all trading periods.

7.4. This constraint sets the upper bound on total flow arriving at river node $h \in H$ at trading period $t \in T$. For the river chains that we model, only Roxburgh has an upper limit on the volume of water arriving at each trading period.

7.5. This constraint sets the upper bound on total flow leaving river node $h \in H$ at trading period $t \in T$.

7.6. This constraint sets the lower bound on total flow leaving river node $h \in H$ at trading period $t \in T$. The lakes Karapiro, Roxburgh, and Waitaki have a minimum flow that must be maintained at all times.

7.7. This constraint sets the lower bound on total flow leaving river node $h \in H$ at night-time trading period $t \in T^N$. Lake Dunstan has a minimum flow that must be maintained during night-time periods.

7.8. This constraint sets the lower bound on non-generating flow between river nodes $\hat{h} \in H$ and $\check{h} \in H$ at trading period $t \in T$. For the river chains that we model, the only minimum non-generating flow that must be maintained is that between Lake Ohau and Lake Ruataniwha.

Constraint 8

This constraint is used when the River Chain Model is solved iteratively. Subject to block dispatch rules, certain river chains, given by set A, are allowed to rearrange the dispatch along their river chain after the system optimal dispatch has been calculated. The aggregate generation after rearranging the dispatch must be equal to the dispatch prior to rearranging. The block dispatch constraints defines the aggregated generation across each river chain $c \in A$. The block dispatch constraint is enforced when the variable for aggregated generation $X^{\Sigma}_{c,t}$ is fixed. For more information on the implementation of block dispatch in our models, see section 3.5.2.2.

Constraint 9

Market node security constraints, or MNode constraints, are a type of constraint implemented in SPD and vSPD (section 3.5). In particular, these constraints provide upper and lower bounds for aggregated generation across groups of stations. These groups of stations may include the Waitaki, Waikato, or Clutha river chains. Therefore, in our stack vSPD model (section 3.5.2.2), where the River Chain Model is solved separately to the vSPD model, we need to include these constraints in order to avoid infeasibility when offers are submitted to the vSPD model. These Market Node constraints that we have formulated can be left out of the Clairvoyant (section 3.5.2.1) and Rolling Central Models (section 3.5.2.3), since vSPD constraints are already present in these models.

Constraint 10

This constraint is used in the Clairvoyant vSPD model (section 3.5.2.1) and the Rolling Central Model (section 3.5.2.3) to map the generation from the river nodes H to the set of stations used in vSPD, S. This constraint is important for the Clairvoyant and Rolling Central models, because it connects the River Chain Model to vSPD. This constraint is also implemented in the River Chain Model used within the Offer Stack Model (section 3.5.2.2), in order to calculate generation that can be offered to vSPD.

Constraint 11

11.1. This constraint models the soft upper bound on generation for each group of stations that is limited by a generation Market Node Constraint. A surplus variable allows the aggregated generation to exceed the market node constraint, but any generation above the soft upper bound is penalized.

11.2. This constraint models the soft lower bound on generation for each group of stations that is limited by a generation Market Node Constraint. A slack variable allows the aggregated generation to ignore the market node constraint, but any generation below the soft lower bound is penalized.

3.2.2 Hydro Boundary Condition Model

In our experiments, we want to be able to compare the results from our models with historical results. In order to get the best comparison with historical data, we need the hydrological boundary conditions of our models to be as close as possible to those observed historically. The boundary conditions that we require for our River Chain Model are the initial and final reservoir volumes for each day and the in-transit flows between days, as well as tributary inflows. The Centralised Data Set (CDS) provides us with tributary inflows, historical generation, and initial and final daily reservoir levels for each major lake. Unfortunately, this data is not ideal. The tributary inflows provided in the CDS are average daily inflows and may only be approximations of the true values. Most of the reservoir volumes for the large lakes are rounded off to the nearest 1,000,000 m^3. Additionally, the levels for minor lakes and head ponds are not provided in the CDS. Additionally, in practice, the energy conversion factors for the station production functions vary with head levels and also with energy production levels.

Because of the approximation or omission of important data points in the CDS, the data for historical generation, inflows, and reservoir volumes do not agree with each other. That is, if we were to fix the hydro generation at its historical levels and assume average inflows and nominal conversion factors, our River Chain Model would not meet historical reservoir volumes. Therefore, we have developed the Hydrological Boundary Condition (HBC) model to calculate a set of reservoir volumes, in-transit flows, half-hourly tributary inflows, and energy conversion factors for our river chain optimisation model. This model is heavily influenced by Philpott and Guan's Inter model, outlined in section 2.4.

The fundamental difference between Philpott and Guan's Inter model and our HBC model, is the treatment of block dispatch. They assumed that the historical generation provided in the CDS was the predispatch, that is, it was not the final generation for stations that are part of a block dispatch group. Therefore, they allowed the historical generation for the Waitaki and Waikato river chains to be rearranged within their Inter model. Communication with Meridian has informed us that the data they provide to the CDS is the final generation at each station. Running the model assuming that the historical data was the final dispatch for the Waikato river, did not result in very good tracing of reservoir volumes. Therefore, we assume that the historical generation data for the Waikato River is able to be reallocated. We also use different penalty weighting factors to Philpott and Guan.

We formulate our HBC model in a similar manner to the River Chain optimisation model in section 3.2.1. However, unlike the River Chain Model, we solve HBC over an 8 day planning horizon (seven days for current week plus the first day of the following week). This planning horizon will be longer for the final week of the year: 9 days for common years and 10 days for leap years. The generation in each trading period for all stations on the Waikato River is allowed to be reallocated in a way that sums up to its aggregated historical generation. All other stations are fixed at their historical generation level. We do, however, allow the conversion factors to vary across the trading periods. We do this because turbine efficiencies are a function of head level and turbine output and are affected by the unit commitment. However, it would be time consuming from a modelling perspective and a computational perspective to model these effects.

We allow the station conversion factors to vary by 10% of the nominal value. 10% is quite a high quantity by which to allow the factors to vary, but it is necessary to maintain feasibility across our simulation. The exception to the 10% rule is Manapouri, which we allow to vary between its nominal value of 1.518 $\frac{MW}{cumec}$ and the value that corresponds to its maximum capacity divided by its maximum generating flow rate, 1.735 $\frac{MW}{cumec}$. Rather than treating tributary inflows as a parameter, we allow them to vary. The inflows at each trading period are allowed to vary between 0 and three times the average inflow value for the day, provided the average of the inflows across the day are equal to the average inflows from the CDS. We do this because we do not know the true half-hourly inflow values, but we hope to get a good approximation by finding a set of feasible values.

We allow the reservoir levels in the final period of each day to vary from historical levels, but varying from the target levels is penalized. Level violations are penalised equally across all reservoirs. In order to convert the violation into units of energy for the objective function, we multiply the volume violation by some conversion factor, which we choose to be lowest conversion factor across all stations. In addition to the level penalties, we impose penalties on spilling, since, in most cases, it is rare in practice. We penalise spill at different rates depending on the station. The penalty for spill is weighted by the efficiency of the station (or stations) being spilled past. For instance, spilling from Lake Scott to Benmore is penalised more heavily than any other spillway, since it spills past Tekapo A, Tekapo B, Ohau A, Ohau B, and Ohau C. Spill past Benmore is penalised more heavily than spill past Waitaki, because Benmore is a more efficient station.

An additional, and more arbitrary, weighting we add to spill is dependent on the station's position within the river chain. For instance, Tekapo A is situated between Lake Tekapo and Tekapo B. Tekapo A has the lowest generating capacity of any station on the Waitaki chain, approximately 25 MW. Lake Tekapo is a large lake, with relatively high inflows and Tekapo B, is a large station relative to Tekapo A. When the system is running close to capacity, Tekapo A cannot provide enough water to fully supply Tekapo B, and it may be necessary to spill around Tekapo A. Therefore, we do not penalise spill around Tekapo A. We also reduce the spill penalty for some other stations that are situated at a bottleneck.

We also do not harshly penalise spill around Manapouri station. The reason for this is the large inflows into Lake Manapouri and Te Anau, due to Manapouri being situated in a region with very high rainfall. Therefore, it is not uncommon for large spills to occur at Manapouri. Instead of placing a hard bound on flow arcs, we penalize violation of flow bounds. This allows more leniency in meeting the target reservoir levels. As with the reservoir volume penalty, we multiply the flow violations by the minimum energy conversion factors, so as to keep units consistent in the objective function. We penalize violation of flow bounds more harshly than we do for spill and for deviation from target reservoir levels. In addition, we place a lower weighting on all violations for the day that we have included from the following week. Therefore, the objective for our model is to minimize the weighted sum of target level violations, spilling penalties, and flow bound penalties.

This model is run sequentially for every week over the years 2005-2009. We assume that the minor lakes begin 2005 at 50% of their total capacity and that major lakes begin at their historical levels. We solve the HBC model for each week, including the first day of the following week. We include the first day of the following week in order to calculate feasible in-transit flows between weeks. The final reservoir volumes for the current week (not including the extra day) are used as the initial reservoir volumes when HBC model is applied to following week.

3.2.2.1 Hydro Boundary Condition Model Formulation

3.2.2.1.1 Sets and Mappings used in Formulation

- T the set of time periods
- T^F the set of final periods, i.e. TP48 for each day of the week
- H the set of all river network nodes: Hydro Stations, Reservoirs and Junctions
- L^M the subset of H for Major Reservoirs (Those with volumes listed in CDS) only
- A the set of River Chains with block dispatch
- B the set of River Chains without block dispatch
- D the set of Days

- $DT(d,t)$ the mapping of days to trading periods
- H^C the set of all river nodes corresponding to river chain $c \in C$
- $S(\hat{h},\check{h})$ the set of spill (wastage) arcs from river node $\hat{h} \in H$ to river node $\check{h} \in H$
- $\overline{\Omega}(\hat{h},\check{h})$ defines the spill arcs from river node $\hat{h} \in H$ to river node $\check{h} \in H$
- $\Omega(\hat{h},\check{h})$ defines generating flow arcs from river node $\hat{h} \in H$ to river node $\check{h} \in H$

3.2.2.1.2 Variables used in Hydro Boundary Condition Model Formulation

- $\overline{X}_h^0$ is the initial generation at river node $h \in H$
- $\widehat{\delta}_{l,f}$ is the surplus above the target reservoir level for each reservoir $l \in L$ in trading period $f \in T^F$
- $\check{\delta}_{l,f}$ is the deficit below the target reservoir level for each reservoir $l \in L$ in trading period $f \in T^F$
- $\widehat{\delta}^{\omega}_{\hat{h},\check{h},t}$ is the surplus above the soft upper bound for flow between river node $\hat{h} \in H$ and river node $\check{h} \in H$ at trading period $t \in T$
- $\check{\delta}^{\omega}_{\hat{h},\check{h},t}$ is the deficit below the soft lower bound for flow between river node $\hat{h} \in H$ and river node $\check{h} \in H$ at trading period $t \in T$
- $\overline{\delta}^{\omega}_{h,t}$ is the surplus above the soft upper bound for flow sent from river node $h \in H$ at trading period $t \in T$
- $\tilde{\delta}^{\omega}_{h,t}$ is the deficit below the soft lower bound for flow sent from river node $h \in H$ at trading period $t \in T$
- $\ddot{\delta}^{\omega}_{h,t}$ is the surplus above the soft upper bound for flow received at river node $h \in H$ at trading period $t \in T$

- $\widehat{\omega}_{\hat{h},\check{h},t}$ is the generating flow leaving from river node $\hat{h} \in H$, en route to station $\check{h}, \in H$ at trading period $t \in T$

- $\breve{\omega}_{\hat{h},\check{h},t}$ is the generating flow arriving from from river node $\hat{h} \in H$, at station $\check{h} \in H$ trading period $t \in T$

- $\overline{\omega}_{\hat{h},\check{h},t}$ is the non-generating flow arriving from $\hat{h} \in H$ at river node $\check{h} \in H$ at trading period $t \in T$

- $\omega_{\hat{h},\check{h},t}$ is the non-generating flow leaving from river node $\hat{h} \in H$ en route to river node $\check{h} \in H$ at trading period $t \in T$

- $Y_{h,t}$ is the river node volume, in m^3, at reservoir $h \in H$ at the end of trading period $t \in T$

- $\check{Y}_{h,t}$ is the volume of flow received, in m^3, by river node $h \in H$ at trading period $t \in T$

- $\widehat{Y}_{h,t}$ is the volume of flow, in m^3, leaving river node $h \in H$ at trading period $t \in T$

3.2.2.1.3 Parameters used in Hydro Boundary Condition Model Formulation

- $X^H_{h,t}$ is the historical generation of river node $h \in H$ at trading period $t \in T$

- U^y_h is the maximum reservoir volume at from river node h $\in H$

- $U^\omega_{\hat{h},\check{h}}$ is the maximum nongenerating flow at from river node h $\in H$

- $U^{\check{y}}_h$ is the minimum total flow arriving at from river node h $\in H$

- $U^{\hat{y}}_h$ is the maximum total flow leaving from river node h $\in H$

- $\lambda^{\hat{y}}_h$ is the minimum total flow leaving river node $h \in H$

- $\overline{\lambda}^{\hat{y}}_h$ is the minimum total flow leaving river node $h \in H$ during the night-time period

- $\lambda^{\omega}_{\hat{h},\check{h}}$ is the minimum nongenerating flow from from river node $\hat{h} \in H$ to from river node $\check{h} \in H$
- Y^0_h is the initial volume of river node $h \in H$
- $Y^T_{h,f}$ is the target volume of river node $h \in H$, for trading period $f \in T^F$
- γ_l is the cost coefficient corresponding to having a shortage of water relative to target reservoir levels for each reservoir $l \in L$
- β_l is the cost coefficient corresponding to exceeding target reservoir levels for each reservoir $l \in L$
- η_h is the conversion factor for from river node $h \in H$, in $\mathrm{m^3s^{-1}/MW}$
- $\eta^{\omega}_{\hat{h},\check{h}}$ is the aggregated conversion factor for river nodes skipped by spill flow from river node $\hat{h}$ to river node $\check{h}$
- $\hat{\tau}$ is the number of hours in a trading period, which is always 0.5 in our experiments
- $\overline{\tau}$ is the number of seconds in an hour, 3600.
- $\check{\tau}$ is the number of trading periods in a day, 48
- $\overline{\alpha}_h$ is the fractional change in conversion factor that we allow for from river node $h \in H$
- $\overline{I}_{h,d}$ is the average inflow into river node $h \in H$ at for day $d \in D$
- $\check{I}_{h,t}$ is the inflow, in m^3, at river node $h \in H$ at trading period $t \in T$
- $\Delta_{\hat{h},\check{h}}$ is the flow delay time between river node $\hat{h} \in H$ and $\check{h} \in H$
- $\widehat{I}_{h,t}$ is the flow in-transit, in m^3, from the previous day at river node $h \in H$ arriving during trading period $t \in T$
- $\hat{\imath}$ is the maximum amount a single half-hourly inflow may be scaled up from the average inflow

- c_l^Y is the penalty for not meeting target reservoir volume at major lake $l \in L$
- $\hat{c}^\omega$ is the penalty for violating flow bounds
- $c^\omega_{\hat{h},\check{h}}$ is the penalty incurred for spilling from river node $\hat{h} \in H$ to river node $\check{h} \in H$
- $\overline{\eta}$ is the minimum conversion factor across all stations.
- $X^\Sigma_{c,t}$ is the sum of generation at river chain $c \in C$ for time period $t \in T$.

3.2.2.1.4 Objective Function for Hydro Boundary Condition Model

$$min\ \hat{\tau}\overline{\tau} \sum^{t \in T} \sum^{(\hat{h},\check{h}) \in S(\hat{h},\check{h})} \omega_{\hat{h},\check{h},t} \eta^\omega_{\hat{h},\check{h}} c^\omega_{\hat{h},\check{h}} + \overline{\eta} \sum^{f \in T^F} \sum^{l \in L^M} c_l^Y (\widehat{\delta}_{l,f} + \check{\delta}_{l,f}) + \overline{\eta}\hat{\tau}\overline{\tau}\hat{c}^\omega \sum^{\hat{h},\check{h} \in H} \sum^{t \in T} (\check{\delta}^\omega_{\hat{h},\check{h},t} + \widehat{\delta}^\omega_{\hat{h},\check{h},t})$$
$$+ \overline{\eta}\hat{c}^\omega \sum^{h \in H} \sum^{t \in T} (\ddot{\delta}^\omega_{h,t} + \tilde{\delta}^\omega_{h,t} + \overline{\delta}^\omega_{h,t})$$

The objective of the HBC model is to minimize the weighted sum of spill wastage, deviation from historical reservoir volumes, and violation of flow constraints. Each term in the objective function is in terms of energy. The flow violations and reservoir volume violations are multiplied by $\overline{\eta}$, the minimum conversion factor across the major chains, because there is no intuitive energy conversion factor for these quantities.

3.2.2.1.5 Hydro Boundary Condition Model Constraints

1. $\overline{X}_{h,t} \geq \sum^{\check{h} \in \Omega(h,\check{h})} \eta_h (1 + \overline{\alpha_h}) \widehat{\omega}_{h,\check{h},t} \qquad \forall h \in H, \forall t \in T$
2. $\overline{X}_{h,t} \leq \sum^{\check{h} \in \Omega(h,\check{h})} \eta_h (1 - \overline{\alpha_h}) \widehat{\omega}_{h,\check{h},t} \qquad \forall h \in H, \forall t \in T$
3. $\overline{X}_{h,t} = X^H_{h,t} \qquad \forall h \in H^B, \forall t \in T$

4. Inflow Constraints

4.1. $\sum^{t \in DT(d,t)} (\breve{I}_{h,t}) / \breve{\tau} = \overline{I}_d$ $\qquad \forall d \in D, \forall h \in H$

4.2. $\breve{I}_{h,t} \leq \hat{i}\overline{I}_{h,d}$ $\qquad \forall (d,t) \in DT, \forall h \in H$

5. Flow Delay Constraints

5.1. $\overline{\omega}_{\hat{h},\check{h},t} = \omega_{\hat{h},\check{h},t-\Delta_{\hat{h},\check{h}}}$ $\qquad \forall \hat{h}, \check{h} \in \overline{\Omega}(\hat{h}, \check{h}), \forall t > \Delta_{\hat{h},\check{h}} \in T$

5.2. $\breve{\omega}_{\hat{h},\check{h},t} = \widehat{\omega}_{\hat{h},\check{h},t-\Delta_{\hat{h},\check{h}}}$ $\qquad \forall \hat{h}, \check{h} \in \Omega(\hat{h}, \check{h}), \forall t > \Delta_{\hat{h},\check{h}} \in T$

5.3. $\breve{Y}_{h,t} = \hat{\tau}\overline{\tau} \left(\sum^{\hat{h} \in \overline{\Omega}(\hat{h},h)} \overline{\omega}_{\hat{h},h,t} + \sum^{\hat{h} \in \Omega(\hat{h},h)} \breve{\omega}_{\hat{h},h,t} \right)$ $\qquad \forall h \in H, \forall t \in T$

5.4. $\widehat{Y}_{h,t} = \hat{\tau}\overline{\tau} \left(\sum^{\check{h} \in \overline{\Omega}(h,\check{h})} \omega_{h,\check{h},t} + \sum^{\check{h} \in \Omega(h,\check{h})} \widehat{\omega}_{h,\check{h},t} \right)$ $\qquad \forall h \in H, \forall t \in T$

6. $Y_{l,f} = Y^T_{l,f} + \widehat{\delta}_{l,f} - \breve{\delta}_{l,f}$ $\qquad \forall l \in L^M, \forall f \in T^F$

7. Conservation of Mass Constraints

7.1. $Y_{h,t} = Y_{h,t-1} + \breve{Y}_{h,t} - \widehat{Y}_{h,t} + \breve{I}_{h,t} + \widehat{I}_{h,t}$ $\qquad \forall t > 1 \in T, \forall h \in H$

7.2. $Y_{h,t} = Y^0_h + \breve{Y}_{h,t} - \widehat{Y}_{h,t} + \breve{I}_{h,t} + \widehat{I}_{h,t}$ $\qquad t = 1, \forall h \in H$

8. Variable Upper and Lower Bounds

8.1. $\overline{X}_{h,t} \leq U^x_{h,t}$ $\qquad \forall h \in H, \forall t \in T$

8.2. $Y_{h,t} \leq U^y_h$ $\qquad \forall h \in H, \forall t \in T$

8.3. $\omega_{\hat{h},\check{h},t} \leq U^{\omega}_{\hat{h},\check{h}} + \widehat{\delta}^{\omega}_{\hat{h},\check{h},t}$ $\qquad \forall \hat{h}, \check{h} \in H, \forall t \in T$

8.4. $\check{Y}_{h,t} \leq U^{\check{y}}_h + \ddot{\delta}^{\omega}_{h,t}$ $\qquad \forall h \in H, \forall t \in T$

8.5. $\hat{Y}_{h,t} \leq U^{\hat{y}}_h + \overline{\delta}^{\omega}_{h,t}$ $\qquad \forall h \in H, \forall t \in T$

8.6. $\hat{Y}_{h,t} \geq \lambda^{\hat{y}}_h - \tilde{\delta}^{\omega}_{h,t}$ $\qquad \forall h \in H, \forall t \in T$

8.7. $\hat{Y}_{h,t} \geq \overline{\lambda}_{h}^{\hat{y}}$ $\forall h \in H, \forall t \in T^{N}$

8.8. $\omega_{\hat{h},\check{h},t} \geq \lambda^{\omega}_{\hat{h},\check{h}} - \breve{\delta}^{\omega}_{\hat{h},\check{h},t}$ $\forall \hat{h}, \check{h} \in H, \forall t \in T$

8.9. All vars ≥ 0

9. $X^{\Sigma}_{c,t} = \sum^{h \in H^{c}} \overline{X}_{h,t}$ $\forall c \in A, \forall t \in T$

Contraint 1

This constraint places an upper bound on the amount we allow the generating flow to vary, for a given generation level. This is equivalent to allowing the conversion factor to vary. However, we don't allow the conversion factors to be variables, since this would make the problem nonlinear.

Contraint 2

This constraint places a lower bound on the amount we allow the generating flow to vary, for a given generation level. This is equivalent to allowing the conversion factor to vary. However, we don't allow the conversion factors to be variables, since this would make the problem nonlinear.

Constraint 3

This constraint fixes a station's generation to its historical level if it is not subject to reallocation. Any station that is not on the Waikato River chain is fixed at its historical level

Constraint 4

4.1. This constraint ensures that the daily average for the inflow variable is equal to the historical daily inflow for each reservoir.

4.2. This constraint restricts the half-hourly inflow variable at river node $h \in H$ on day $d \in D$ to be no more than $\hat{i}$ times higher than the daily average inflow for river node h on day d.

Constraint 5

These constraints model the intertemporal delay between flow leaving river node $\hat{h}$ at trading period t and arriving at river node $\check{h}$ at trading period $t + \Delta_{\hat{h},\check{h}}$.

5.1. This constraint equates the flow arriving at river node $\check{h}$ at trading period t with the flow leaving river node $\hat{h}$ at trading period $t - \Delta_{\hat{h},\check{h}}$. this constraint is defined over all trading period later than $\Delta_{\hat{h},\check{h}}$ and over all defined pairings of $\hat{h}$ and $\check{h}$. For all periods less than $\Delta_{\hat{h},\check{h}}$, we have in-transit flows from the previous day. These in-transit flows are included in constraint 7.

5.2. This constraint equates the generating flow arriving at river node $\check{h}$ at trading period t with the flow leaving river node $\hat{h}$ at trading period $t - \Delta_{\hat{h},\check{h}}$. this constraint is defined over all trading period later than $\Delta_{\hat{h},\check{h}}$ and over all defined pairings of $\hat{h}$ and $\check{h}$. For all periods less than $\Delta_{\hat{h},\check{h}}$, we have in-transit flows from the previous day. These in-transit flows are included in constraint 7.

5.3. This constraint calculates the flow received, in m^3 by each river node h at trading period t. This flow excludes tributary inflows and flows in-transit from the previous day.

5.4. This constraint calculates the flow sent, in m^3 by each river node h at trading period t. This flow excludes tributary inflows and flows in-transit from the previous day.

Constraint 6

The final reservoir volume constraint sets a target level for each reservoir l to meet for the final trading period of the day. Slack and surplus variables allow the reservoir levels to vary above or below the target levels. However, penalty terms in the objective function penalize deviation from the target levels.

Constraint 7

7.1. Conservation of mass constraint defined for all periods later than TP1. The conservation of mass constraint calculates the reservoir volume for each river node h at each trading period t, by subtracting all outflows and adding all inflows from the reservoir level at trading period $t - 1$.

Tributary inflows, in-transit flows, and incoming controlled flows from other stations, reservoirs, and junctions are added to the reservoir, and all outgoing controlled flows are subtracted from the reservoir.

7.2. Conservation of mass constraint defined for the first trading period. The conservation of mass constraint calculates the reservoir volume for each river node h for TP1, by subtracting all outflows and adding all inflows to the initial reservoir level. Tributary inflows, in-transit flows, and incoming controlled flows from other stations, reservoirs, and junctions are added to the reservoir, and all outgoing controlled flows are subtracted from the reservoir.

Constraint 8

These constraints provide upper and lower bounds for each of the variables in the river chain problem.

8.1. Each station has an upper bound on its generation. This will be set to zero for all junctions and for lakes that are not paired with a generating station.

8.2. This constraint defines the upper bound on reservoir volume for each river node $h \in H$ at trading period $t \in T$. For all junctions and for all stations not paired with a lake, this upper bound is set to zero.

8.3. This constraint sets the soft upper bound on non-generating flow between river nodes $\hat{h} \in H$ and $\check{h} \in H$ at trading period $t \in T$. This constraint is defined for all valid pairs of $\hat{h}$ and $\check{h}$ and over all trading periods. Violating this flow constraint incurs a penalty.

8.4. This constraint sets the soft upper bound on total flow arriving at river node $h \in H$ at trading period $t \in T$. For the river chains that we model, only Roxburgh has a limit on the volume of water arriving at each trading period. Violating this flow constraint incurs a penalty.

8.5. This constraint sets the soft upper bound on total flow leaving river node $h \in H$ at trading period $t \in T$. For the river chains that we model, only Roxburgh has a limit on the volume of water leaving at each trading period. Violating this flow constraint incurs a penalty.

8.6. This constraint sets the soft lower bound on total flow leaving river node $h \in H$ at trading period $t \in T$. The lakes Karapiro, Roxburgh, and Waitaki have a minimum flow that must be maintained at all times. Violating this flow constraint incurs a penalty.

8.7. This constraint sets the lower bound on total flow leaving river node $h \in H$ at night-time trading period $t \in T^N$. Lake Dunstan has a minimum flow that must be maintained during night-time periods.

8.8. This constraint sets the soft lower bound on non-generating flow between river nodes $\hat{h} \in H$ and $\check{h} \in H$ at trading period $t \in T$. For the river chains that we model, the only minimum non-generating flow that must be maintained is that between Lake Ohau and Lake Ruataniwha. Violating this flow constraint incurs a penalty.

Constraint 9

Subject to block dispatch rules, certain river chains, given by set A, are allowed to rearrange the dispatch along their river chain after the system optimal dispatch has been calculated. The aggregate generation after rearranging the dispatch must be equal to the dispatch prior to rearranging. The block dispatch constraints sets the aggregated generation across each river chain $c \in A$ equal to the historical aggregated generation for each trading period $t \in T$. In this model, the Waikato River is the only chain subject to block dispatch.

3.3 Model for Competitive Equilibrium

3.4 Half-hourly Models

For our experiments, we wish to compare the historical dispatch to a counterfactual model that assumes that agents do not act strategically. A number of models were developed with the intent to simuate the half-hourly process of generators offering competitively into the market with uncertainty about future prices and being dispatched by an SPD mechanism with uncertainty about future demand. The half-hourly models we have developed are the Simple Pricetaking model and the Stack vSPD model. These models differ in the way that the price signals are processed in order to calculate offers and whether the offers are submitted in the form of an offer stack or a single quantity. Each of the half-hourly dispatch models have the following general procedure in common. At the beginning of each trading period, each major hydro generator solves the River Chain Model seeking to maximise their revenue over the remaining trading periods, given a set of predicted prices for the day. From the solution to each River Chain Model, a series of energy offers are produced for the remaining trading periods. The thermal generators offer their maximum generation at the cost of fuel consumption. The offers for each station are then submitted to the System Operator. At this stage, it is assumed that the demand for the current period becomes known to the System Operator and the demand for all subsequent periods is reforecasted. The System Operator solves the SPD model, producing a minimum cost dispatch. The SPD model provides the generators with updated predictions for the nodal prices for the remaining trading periods. The major hydro generators are able to rearrange the generation along their river chain, matching the total amount for which they were dispatched in the current period. The generation for the current trading period is fixed, and the model rolls forward to the next trading period, where the process is repeated with updated pricing signals.

3.4.1 Simple Pricetaker Model

Refer to Appendix A for a detailed pseudocode description of the Simple Pricetaker Model's process.

This simple model assumes the major hydro generators are price takers that offer the quantity they want dispatched at price zero. This model begins by setting the projected prices to be equal to the previous day's prices, for all trading periods. At the beginning of each trading period, the major hydro generators perform a single solve of the river chain optimisation problem, maximising their expected revenue, due to the predicted prices, over the remaining trading periods. The quantities produced from this solution are offered at zero price. The thermal generators offer their maximum generation at the cost of fuel consumption. The offers are then submitted to the system operator. The demand for the current period becomes known and the demands for the subsequent periods are reforecasted.

The System Operator solves the SPD problem, minimizing dispatch cost, and provides the generators with updated nodal prices, which they will plug directly into their river chain optimisation. The Waitaki and Waikato river chain controllers are able to rearrange their generation along their river chain, equalling their total dispatched quantity. The current trading period's generation is fixed, and the model rolls forward to the next period.

This model was tested on a condensed representation of New Zealand's transmission network. In this test run, the production functions (generation in terms of flow rate) for hydro generators were convex quadratic functions and the cost functions (cost in terms of generation) for the thermal generators were also convex quadratic functions. Test runs with the Simple Pricetaker model did not provide stable solutions. The generation offers being produced were volatile with respect to price and the price was volatile with respect to offers. Therefore, in the upcoming sections, we propose an offer stack generation algorithm that operates on a full-scale representation of the New Zealand grid. This model is called the Stack vSPD model. In addition, we will introduce the Clairvoyant model and the Rolling Central models.

3.5 Integration with vSPD

In *Models for estimating the performance of electricity markets with hydroelectric reservoir storage*, Philpott and Guan conclude that a more comprehensive study would include a full-scale representation of the New Zealand grid with provisions made for spinning reserve and other ancillary services [27]. vSPD, which is a clone of Transpower's SPD model, provides ancillary services, such as spinning reserve, tailwater depressed reserve, and interruptible load reserve. Additionally, vSPD provides a full-scale (285 node) model of the New Zealand national grid. In our experiments, we take advantage of the full-scale representation of the New Zealand transmission network, but we still ignore reserve in our counterfactual models. We choose to ignore reserve for a number of reasons. The fundamental reason for neglecting reserve is the fact that the historical reserve offers would have been caculated in tandem with the historical generation offers. In our models, we do not use historical offers, so there may be issues with reserve offers clashing with the generation offers. Therefore, if we were to implement reserve offering in our models, we would want to develop a method for calculating optimal reserve offers. Due to time constraints, we have decided that including a reserve offer optimisation should be left to future work. In addition to providing a full-scale network, the GDX files required to run vSPD provide all necessary transmission and station outage information for our simulations.

A number of sets, variables, and parameters used in the vSPD model are used to connect vSPD to our Central and Rolling models. The key sets, variables, and parameters are shown in Figure 3.2. *i_Offer* is the set of all offering generators, *i_TradePeriod* is the set of all trading periods in the day, *i_Node* is the set of all Grid Exit Points (GXP) and Grid Injection Point(GIP). $i\_TradePeriodEnergyOffer$

contains the generation offer quantity and generation offer price for each offering generator in each trading period. *i_TradePeriodOfferParameter* contains limits on ramping up and down, initial generation level, and the aggregated maximum reserve and generation for the each offering station in each trading period. The maximum reserve and generation parameter includes a subtraction of generator outages. *i_TradePeriodNodeDemand* contains the energy demand at each GXP in each trading period. *i_TradePeriodMNodeConstraintRHS* contains market node security constraints on generation, demand, and reserve [11]. In particular, these constraints provide the minimum and maximum levels for groups of stations that may include the Waitaki River Chain, the Waikato River Chain, or the Clutha River Chain. We implement these in our river chain formulation.

Name	Type	Relevance
i_Offer	Set	Set of offering stations
i_TradePeriod	Set	Set of trading periods
i_Node	Set	Set of GXP and GIP. Contains the central GIP for each river chain
i_TradePeriodEnergyOffer	Parameter	Offers for each trading period and station. Altered for use in our counterfactual models.
i_TradePeriodNodeDemand	Parameter	Altered for our Rolling Central and Stack vSPD models.
i_TradePeriodOfferParameter	Parameter	Contains Reserve and Generation maximum which are used by our models to reflect derating. Also contains ramp rates.
i_TradePeriodMNodeConstraintRHS	Parameter	Key variable utilised by the River Chain Model to limit total generation for each river chain.
o_NodePrice_TP	Parameter	Used to generate our stacks for Stack vSPD
Generation	Variable	The generation at each station and trading period. Utilised in River Chain Model, vSPDR, vSPD Central, vSPD

Figure 3.2: Key vSPD Parameters, sets, and variables

vSPD penalizes violation of its network constraints. Figure 3.3 provides a summary of the constraint violation variables and penalty costs in vSPD relevant to this study.

SurplusBranchFlow	Variable	Violation of lines upper limit. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $110,000/MWh
SurplusBusGeneration	Variable	Surplus generation above GXP demand. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $100,000/MWh
DeficitBusGeneration	Variable	Deficit generation below GXP demand. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $100,000/MWh
SurplusRampRate	Variable	Violation of Ramping Upper Limit. Utilised in River Chain Model (RCM), vSPDR, vSPD Central, and vSPD. Penalised at $110,000/MWh
DeficitRampRate	Variable	Violation of Ramping Lower Limit. Utilised in RCM, vSPDR, vSPD Central, and vSPD. Penalised at $110,000/MWh
SurplusACNodeConstraint*	Variable	Violation above AC node net injection security constraint upper limit. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $105,000/MWh
DeficitACNodeConstraint*	Variable	Violation of AC node net injection security constraint lower limit. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $105,000/MWh
SurplusMNodeConstraint	Variable	Violation of Market Node Security constraint upper limit. Utilised in RCM, vSPDR, vSPD Central, and vSPD. Penalised at $130,000/MWh
DeficitMNodeConstraint	Variable	Violation of Market Node Security constraint lower limit. Utilised in RCM, vSPDR, vSPD Central, and vSPD. Penalised at $130,000/MWh
SurplusBranchSecurityConstraint	Variable	Violation of Branch Security constraint upper limit. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $130,000/MWh
DeficitBranchSecurityConstraint	Variable	Violation of Branch Security constraint lower limit. Utilised in vSPDR, vSPD Central, and vSPD. Penalised at $130,000/MWh

Figure 3.3: Key infeasibility violations for our vSPD models [2]

*The penalty cost for this variable is not available in [2]. The numbers are taken from the FP_20090101.gdx file.

3.5.1 Initial Alterations to vSPD code

In order to model the hydrological systems, a new set representing each of the stations, lakes, junctions, and headponds needs to be introduced. Let this set be represented by H. Each generating station in H is mapped to their corresponding station (or stations) in the set *i_offer*. For simplicity in our optimisation, each river chain is optimised using a single reference node. These reference nodes are $WKM2201, BEN2201, ROX2201$, and $MAN2201$ for the Waikato, Waitaki, Clutha, and Manapouri schemes, respectively.

The ramping constraints in vSPD do not function dynamically [11]. This means that the bounds on $Generation_{i\_TradePeriod,i\_Offer}$ are not dependent on the level of $Generation_{i\_TradePeriod-1,i\_Offer}$, but instead, these bounds are calculated a priori from parameters $i\_InitialMW_{i\_TradePeriod,i\_Offer}$, $i\_RampUpRate_{i\_TradePeriod,i\_Offer}$, and $i\_RampDownRate_{i\_TradePeriod,i\_Offer}$ under $i\_TradePeriodOfferParameter$ provided in the GDX file [11]. $i\_InitialMW_{i\_TradePeriod,i\_Offer}$ gives the historical generation for each offering generator at the beginning of each trading period for the day being studied. This means that, if we are changing the quantities and prices that are being offered to vSPD, then these ramp constraints will not be valid. In order to fix this, we introduce a new model that differs from vSPD primarily in the fact that it replaces vSPD's static ramping constraints with one that links the generation in the current period with generation from the previous period. The vSPD model with dynamic ramping will be known as vSPDR. The vSPDR model is also adapted to include a contract between Tiwai Point and Meridian for a continuous generation of 572 MW. For more information on this contract, refer to section 3.5.2.2.

Vectorisation is a very important aspect of vSPD. If Vectorisation is switched off, vSPD dispatches each of the trading periods separately. When vectorisation is switched on, vSPD dispatches the entire day in one solve. With vectorisation switched on, the main "loop" in the *vSPDsolve.gms* code functions as a block, that is, it does not loop. Vectorisation is always switched on in our models involving vSPD. If vectorisation is not switched on, then dynamic ramping constraints and reservoir storage constraints applied to the vSPD model cannot be enforced. The options *i_ResolveHVDCNonPhysicalLosses* and *i_ResolveCircularBranchFlows*, when switched on, will turn vectorisation off and re-solve vSPD using a MIP solver, if the model encounters non-physical losses in the HVDC branches or circular branch flows. Because these options may turn off vectorisation, we switch these options off.

3.5.2 Models used in Integrated vSPD

The first model that is solved is a version of vSPD with no altered parameters, constraints, variables etc. The solution from this model provides the historical dispatch for all of the non-offering generators, which is then offered in at a price of zero for each of our market simulation models. In order to compare the historical dispatch to our market simulation models, we then pass the generation from each thermal station through the same fuel cost calculation used in sections 3.5.2.1, 3.5.2.2, and 3.5.2.3, in order to get the fuel costs. In addition, all penalty costs from vSPD are added to the fuel cost to get the total system cost. In the following subsections, we will go over the other models solved in vSPD.

3.5.2.1 Clairvoyant Model Rationale

Refer to Appendix A.2 for a detailed pseudocode description of the Clairvoyant model's process.

The Clairvoyant model provides a perfectly competive equilibrium solution for the full representation of New Zealand's wholesale electricity market, assuming perfect foresight for demand and tributary inflows over 48 trading periods. We model the Clairvoyant model as a linear program that schedules the hydro and thermal generation over the New Zealand Transmission network. Therefore, this model can be seen as an amalgamation of the river chain optimisation model and the vSPDR model. Features that the clairvoyant model have in common with a day-ahead solution include improvements in coordination inefficiency compared to a real-time spot market and the scheduling of dispatch over all 48 periods at once. Because of these factors in common between the two market structures, we can view this clairvoyant model as a proxy of a day-ahead market. Because a day-ahead market benefits participants by allowing them to coordinate their unit commitment, it provides a higher loss of coordination efficiency than the clairvoyant model, and hence, an upper bound on efficiency loss. In future works, it would be beneficial to build a fully functional day-ahead market model to further investigate the worth of implementing a day-ahead market structure in New Zealand. We call the version of vSPD altered to include the scheduling of hydro generation the vSPD Central model. The vSPD Central model is used in the Clairvoyant model algorithm as well as the Rolling Central model outlined in section 3.5.2.3

The power stations in the four major hydro schemes (Waikato, Waitaki, Clutha, and Manapouri) and the major thermal and non-embedded cogeneration (Huntly, Otahuhu, Stratford, Whirinaki, Southdown, Te Rapa) are the stations that we allow to offer into the market. All other generation, which is primarily small hydro, embedded generation, and embedded cogeneration are offered at their historical levels at an offer price of zero. Wind generation is already subtracted from the demand values, therefore it does not need to be handled. We do not use the historical generation offers for our offering generators. This is because the historical offers may have been strategic in nature and, therefore, do not align with the objectives of these experiments.

The thermal generators offer in five tranches of equal quantity, which sum up to the *ReserveGenerationMaximum* parameter defined under *i_TradePeriodOfferParameter*. Ideally, we would like to model the marginal thermal cost as a piecewise constant function, where an increasing marginal cost approximates the decrease in marginal efficiency of the thermal generators as output in increased. However, we do not have data on how the marginal thermal costs change with power output. We do, however, model the cost of operations and maintenance costs in our thermal cost functions. Therefore, the offer price for thermal generation for all five tranches is set to the product of the station's heat rate and the seasonal price of the fuel that the station burns plus the marginal operational and maintenance cost. Hydro generation is offered in a single tranche zero-priced quantity equal to the stations maximum generation, defined by the *ReserveGenerationMaximum* parameter. We do not model reserve in the clairvoyant model. This is due to historical reserve offers being coordinated with historical generation offers. Since we do not use historical generation offers, we leave out the historical reserve offers.

Since vSPD has a set containing the hydro stations, *i_offer*, or S^H in our paper formulation, but no sets corresponding to the lakes and junctions, we need to introduce a set for these components. We introduce a set, H, that includes all the stations, reservoirs, and junctions. The generation for the stations in set H is then mapped to the generation for the hydro stations in set *i_offer*. In hindsight, it could be simpler for H to be a set of reservoirs and junctions only, and map the stations in *i_offer* to their adjacent reservoirs and junctions. However, the set definition that we implemented was chosen because it was compatible with the way that the River Chain Model was formulated prior to integration with vSPD. In vSPD, a variable, *HydroGeneration*, is introduced to model the generation corresponding to each station in H over each time period and this generation is mapped to the *Generation* variable native to vSPD in order to link the river chain formulation with vSPDR.

As with the Stack vSPD model and the Rolling Central models below, we include the Tiwai-Meridian contract for continuous generation of 572 MW. The primary purpose for including this contract in our dispatch models is that it makes the Stack vSPD model more stable by hedging against volatile prices. Therefore, for more information on this contract, refer to section 3.5.2.2. The total generation on the Waikato, Waitaki, or Clutha river chains may also be restricted by the market node constraints (section 3.5).

We calculate the water value in order to allow our rolling models to have more flexibility with respect to meeting the target reservoir levels. Clearly, the value of water in a reservoir will increase as the volume remaining in the reservoir decreases, and vice versa. Since we want to keep the model linear to retain tractability, we model the water value as a two-piece piecewise linear function with the break point for each reservoir centered on the end of day historical water level for each reservoir. For each $l \in L$, β_l is the water value coefficient corresponding to exceeding the reservoir level for lake l, and γ_l is the penalty for the final volume being less than the target volume for lake l. β_l is always less than γ_l. We define the cost (or revenue) of not meeting the target reservoir volume as $\sum^{l \in L} (\beta_l \widehat{\delta_l} - \gamma_l \breve{\delta_l})$, where $\breve{\delta_l}$ is the deficit on meeting the target reservoir levels and $\widehat{\delta_l}$ is the surplus. This calculation is added onto the objective function of the vSPD Central model. Clearly, if γ_l is infinity and β_l is negative infinity, then the absolute deviations on the final reservoir levels will be minimized as much as possible. The first step for estimating β_l and γ_l is to set them to very low and very high values respectively. For computational reasons, we can not set them to infinity and negative infinity. Running vSPD Central with these extreme estimates, we can obtain initial estimates of β_l and γ_l as the shadow price on the initial reservoir volume constraint. If, for some reason, the reservoir levels do not meet the target, then the minimum possible absolute deviation on target levels for each reservoir is calculated. In this case, the dual variable on initial storage will be a positive or negative number of a very large order of magnitude, so we set the initial β_l and γ_l estimates for these lakes to $\$0.02/m^3$. We then adjust the value of β_l downwards and γ_l upwards as necessary and rerun the vSPD Central iteratively with the new values of β_l and γ_l, until the deviations from target levels converge to within epsilon of the minimum possible target level deviation.

In addition to target reservoir levels, we have in-transit flow targets at the end of each day. If we fail to include these in-transit flow targets, the hydrological models will view flows in transit at the end of the planning horizon as wasted water, and the models would prefer to have delayed flow arrive within the planning horizon. We model the target in-transit flows in a similar manner to the target reservoir levels, where we have a two-piece piecewise linear water value function for the cost of being above or below the target in-transit flows. For each $h \in H$, β_h^ω is the water value coefficient corresponding to exceeding the total volume of in-transit flows destined for hydrological node h, and γ_h^ω is the penalty for the total volume of intransit flows destined for hydrological node $h \in H$ being less than target volume. β_h^ω is always less than γ_h^ω. We define the cost (or revenue) of not meeting the target reservoir as $\sum^{h \in H}(\beta_h^\omega \widehat{\delta^\omega}_h - \gamma_h^\omega \breve{\delta^\omega}_h)$, where $\breve{\delta^\omega}_h$ is the deficit on meeting the target volume in-transit and $\widehat{\delta^\omega}_h$ is the surplus. This calculation is added onto the objective function of the vSPD Central model. The calculation of these terms is performed simultaneously with the calculation of β_h and γ_h. The first step for estimating β_h^ω and γ_h^ω is to set them to very low and very high values respectively. For computational reasons, we can not set them to infinity and negative infinity. Running vSPD Central with these extreme estimates, we can obtain an initial estimate of β_h^ω and γ_h^ω as the shadow prices on the initial reservoir volume constraint. If, for some reason, the total flow in-transit flows for each hydrological node do not meet the target, then the minimum possible absolute deviation on target in-transit volume for each reservoir is calculated. In this case, the dual variable on initial storage will be a positive or negative number of a very large order of magnitude, so we set the initial β_h^ω and γ_h^ω estimates for these hydrological nodes to $\$0.02/m^3$. We then adjust the value of β_h^ω downwards and γ_h^ω upwards as necessary and rerun the vSPD Central iteratively with the new values of β_h^ω and γ_h^ω, until the deviations from target in-transit flows converge to the minimum possible target in-transit deviation.

Prices produced by the Clairvoyant model are influenced by the presence of constraints on water transfer between periods. Therefore, if we want to compare the prices from the Clairvoyant model to prices produced from models where the hydro production is not planned centrally, such as the Stack vSPD model introduced later in this chapter, we need to re-solve the problem using the same vSPD model used in the rolling problems, vSPDR. After the optimal solution to vSPD Central is obtained, the variable upper bound on the *Generation* variable is set to equal the optimal generation from the Clairvoyant vSPD Central solution, $X^*_{s,t}$. This quantity is then offered into vSPDR, in order to produce a solution with prices that can be compared with the Stack vSPD solution, without affecting the optimal dispatch. As well as the optimal dispatch, the output of the most recently solved vSPD Central model provides us with optimal water releases and reservoir volumes.

3.5.2.2 Stack vSPD Rationale

Refer to Appendix A.3 for a detailed pseudocode description of the Stack vSPD model's process.

The Stack vSPD model, as with the other rolling dispatch models, was designed to simulate how market participants behave in the absence of market power, but with an uncertain view of future demand and clairvoyance with respect to tributary inflows, and without a means of coordination between each participant. This model is integrated with vSPD, and it operates over a full representation of the New Zealand transmission network. Our earlier model, the simple half-hourly pricetaker model does not take into account the effects of uncertainty in prices and, as a result, produces unstable results. This instability is caused by hydro generators choosing not to generate when they expect the prices to be low and consequently driving the prices up. By taking into account a range of possible prices, we attempt to negate the effect of hydro producers withholding their production when they expect the price to be low. We achieved this by extending the Simple Pricetaker model to incorporate an offer stack generation algorithm. The offer stack generation algorithm produces an offer stack for each offering hydro station comprising five offer quantities at five corresponding price levels. For each time period, $\bar{t}$, of the Stack vSPD, this algorithm produces an offer stack for $\bar{t}$ and a price/quantity pair for all subsequent periods. The algorithm is incorporated into vSPD by placing the trading period iteration loop around the main *vSPDsolve.gms* program block. We do not extend the planning horizon each time we roll to the next trading period. This is done for simplicity, especially with respect of our GDX files, which are broken into daily data.

The power stations in the four major hydro schemes (Waikato, Waitaki, Clutha, and Manapouri) and the major thermal and non-embedded cogeneration (Huntly, Otahuhu, Stratford, Whirinaki, Southdown, Te Rapa) are the stations that we allow to offer into the market. All other generation, which is primarily small hydro, embedded generation, and embedded cogeneration are offered at their historical levels at an offer price of zero. Wind generation is already subtracted from the demand values, therefore it does not need to be handled. We do not use the historical generation offers for our offering generators. This is because the historical offers may have been strategic in nature and, therefore, do not align with the objectives of these experiments.

The thermal generators offer in five tranches of equal quantity, which sum up to the *ReserveGenerationMaximum* parameter defined under *i_TradePeriodOfferParameter*. Ideally, we would like to model the marginal thermal cost as a piecewise constant function, where an increasing marginal cost approximates the decrease in marginal efficiency of the thermal generators, as output in increased. However, we do not have data on how the marginal thermal costs change with power output. We do, however, model the cost of operations and maintenance costs in our thermal cost functions. Therefore, the offer price for thermal generation is set to the the product of the station's heat rate and the seasonal price of the fuel that the station burns plus the marginal operational and maintenance cost. Below, we describe the offering of hydro generators in detail.

For the first trading period, $\bar{t}$, of the Stack vSPD model, the previous day's nodal prices are used to predict the current day's prices, $P_{n,t}$, for the purpose of planning hydro generation. In earlier models, we used the previous day's prices directly as our price predictions for the day being studied. However, there are flaws in this method. The first flaw is that it does not take into account the fact that price profiles depend on the day of week. Additionally, this method does not take into account the likelihood that the previous day's prices may have been outliers. Our improved method predicts the price for each period of the day, given that the previous day's price in the corresponding period falls within a particular interval, i.

Our method for calculating the price predictions stratifies the pricing data by day of week and nodes of interest, n, for the years 2005-2009. Within each stratified sample, we paired the price, $p_{2,n,d,t}$, at each trading period, t, and day, d, with the price at the same trading period from the previous day $p_{1,n,d,t}$. The data pairs are sorted into intervals dependent on the values of $p_{1,n,d,t}$. The data sorted into intervals is represented by the pair $(p'_{1,n,d,t,i}, p'_{2,n,d,t,i})$. The mean of $p'_{2,n,d,t,i}$, , $\Lambda_{i,n}$, across all the days and trading periods is obtained for each interval and node. $\Lambda_{i,n}$ is our projected price, and is unique for each day of the week. For all subsequent periods, $P_{n,t}$ are equal to the nodal prices calculated by solving SPD.

At the beginning of each trading period, the agents with hydroelectric generation solve river chain optimization models in order to calculate their offers. In order to calculate the quantities for each tranche of the offer stack, each agent's problem must be solved once for each tranche. Because of the intertemporal storage of the hydroelectric reservoirs, the agents must solve this problem across all remaining periods in the day. The hydro agents offer in a five tranche offer stack, therefore each agent solves their river chain optimisation five times for each trading period. The prices that the hydroelectric agents use in their optimization must be chosen carefully. We assume that the tranches are ordered by increasing marginal cost, and we use a uniform pricing scheme. Therefore, if a station is dispatched at any tranche other than its top tranche, the station's owner can expect to be paid a price greater than or equal to the offer price for the station's top dispatched tranche, but lower than the offer price of the station's next tranche. If a station is dispatched at its full offered quantity, then the owner will be paid some price greater than or equal to the offer price of the station's fifth tranche. Therefore, when solving for the quantities for each tranche, the objective function for the River Chain Model must use the conditional expectation on price, given that the relevant tranche is the top dispatched tranche.

For our offer stack algorithm, we assume that the price breaks and the conditional expectation on price for each tranche are dependent on the price from the previous period. In order to calculate these values, historical price data was stratified by each river chain's central node over the years 2005 to 2009. Within each stratified sample, we paired the price at each trading period and day, $p_{2,n,d,t}$ with the price from the previous trading period, $p_{1,n,d,t}$. The data pairs are then sorted into intervals based on $p_{1,n,d,t}$. The data sorted into intervals is given by the pair $(p'_{1,n,d,t,i}, p'_{2,n,d,t,i})$. For each interval, the standard deviation, $\sigma_{2,n,i}$, and mean, $\mu_{2,n,i}$ are calculated across all trading periods and days for $p'_{2,n,d,t,i}$. The price break, $\widehat{\pi}_{n,r,i}$, for each tranche, r, and node, n, is calculated using the mean and standard deviation for each interval, i. The price break for the third tranche is $\mu_{2,n,i}$ and the price breaks for the other tranches are determined by $\sigma_{2,n,i}$ and a parameter, ϕ. We set ϕ equal to 1 for our experiments. The price breaks for tranches 2 and 4 are ϕ standard deviations away from $\mu_{2,n,i}$ and the price breaks for tranches 1 and 5 are $2 \times \phi$ standard deviations away from $\mu_{2,n,i}$. Within each of the intervals, the data is further split into five intervals corresponding to each of the tranches. The pairs for the data in this interval are represented as $(p''_{1,n,d,t,i,r}, p''_{2,n,d,t,i,r})$ These tranche intervals correspond to the price breaks calculated, that is, if $p''_{2,n,d,t,i,r}$ is greater than or equal to $\widehat{\pi}_{n,r,i}$, but less than $\widehat{\pi}_{n,r+1,i}$, then the pair $(p''_{1,n,d,t,i,r}, p''_{2,n,d,t,i,r})$ is included in interval r. For each of these tranche intervals, the mean of $p''_{2,n,d,t,i,r}$ across all days d, and all trading periods t, gives the conditional expectation, $\tilde{\pi}_{n,r,i}$, corresponding to each tranche, r, node of interest, n, and bin interval, i.

Given the previous period's price at each river chain's central node is in interval i, the conditional expectation, $\tilde{P}_{n,r}$, and price breaks, $\widehat{P}_{n,r}$, can be calculated from $\tilde{\pi}_{n,r,i}$ and $\widehat{\pi}_{n,r,i}$, respectively. For each tranche of the offer stack, each agent's river chain problem is solved, maximizing the profit to the agent assuming the price at the current period is equal to $\tilde{P}_{n,r}$ and the prices for all future periods are equal to $P_{n,t}$ for all stations centered around node n. We keep the future prices, $P_{n,t}$, constant across the solves for each tranche in order to guarantee a monotonic increase in offer quanitity as we increase the price for the current period. The optimal generation, $X^*_{h,\bar{t}}$, from each river chain solve can be interpreted as the quantity that the agent would be willing to have dispatched at hydro station h, if price $\tilde{P}_{n,r}$ were to eventuate at the river chain's central node. Therefore, for each tranche, the quantity offered for the current period is $X^*_{h,\bar{t}}$ minus the sum of offer quantities for the lower tranches.

In our experiments, we altered the price breaks and conditional expectation for the first and fifth tranches for the current period's offer stack. The conditional expectation for the first tranche is set to \$0.01, and is offered in at \$0. This alteration is made to ensure that each station will always be dispatched the quantity that is necessary for that station. We also alter tranche 5 to ensure that there is enough power being offered to the system operator at all times, in order to minimize constraint violation. To do this, we choose to offer the fifth tranche at a price equal to double the water value at each station, and we set the conditional expectation to be 2.4 times the value of water at each station. We choose 2.4 because 1:1.2 is the average ratio of offer price to conditional expectation in our data.

For all future periods, we submit a two tranche offer stack. For the first tranche of the future offers, $X^*_{h,\bar{t}}$ corresponding to the third tranche — the median tranche — are offered at price zero. For the second tranche of the future offers, the remaining capacity of the stations is offered at the maximum fuel cost across the system. The offers for the future periods are submitted so that the system operator can calculate forecast prices to aid the planning process for the hydro agents. We submit this second tranche at the hydro stations' capacity to ensure that no shortages are planned for the future periods, since shortages produce large price spikes, possibly resulting in some suboptimal behaviour. The offers are stored in the vSPD parameter *i_TradePeriodEnergyOffer* and submitted to vSPDR.

From the second trading period onward, the dispatch from the previous trading period on each of the Waitaki and Waikato river chains is allowed to be rearranged subject to block dispatch rules. Since the rearranged generation may differ between each of the tranches, the generation and releases that are fixed from the previous period are the optimal dispatch and releases calculated using the conditional expectation corresponding to the median tranche, tranche 3. In addition to the dispatch and flow releases, we also fix the AC and HVDC line flows from the previous period.

The Stack vSPD model uses piecewise water value coefficients calculated by the Clairvoyant solution. For details on the calculation of these coefficients, see section 3.5.2.1. The cost of not meeting the target reservoir levels and end of day in-transit flows is added onto the objective function for the River Chain Model. By adding this term into the objective function, and allowing the final reservoir volume and flows in transit to vary from the target levels allows each hydro planner to recover if they have over or under committed their generation early on the day. In addition, it may prevent the hydro planners from over or under committing their generation by giving them an incentive to either use less or more water than is required to meet the target levels, if this is deemed profitable.

In our experiments, we found that there was potential for electricity shortages in the South Island if Manapouri did not maintain a fairly steady level. This is due in part to Tiwai Point, a large aluminium smelter in the vicinity of Manapouri, consuming electricity at a fairly constant rate near to 600 MW. In practice, there is a contract between Meridian Energy and Tiwai point for a continuous generation of 572 MW. Meridian owns Manapouri, as well as the relatively nearby Waitaki chain. In order to put in place this contract within the river chain optimisation, we need to consider the transmission losses, which are not already modelled by the river optimisation problem. Therefore, we calculated an approximate linear loss factor, l_h from Manapouri to Tiwai Point and another approximate loss factor for generation from the Waitaki chain.

We introduce a new variable, $\tilde{X}_{h,t}$, into the river chain optimisation that represents the amount of generation from each station that is being dedicated to meeting the Tiwai point contract. The weighting of each stations contribution to the contract is equal to $1 - l_h$. A constraint was then put in place that sets the sum of $(1 - l_h) \times \tilde{X}_{h,t}$ across each of Meridian's stations to be equal to 572 MW for each trading period t. Since Meridian gets paid a fixed price on this contract,the generation allocated to the contract, $\tilde{X}$ is subtracted from the generation in the objective function. This contract is applied to the River Chain Model as well as vSPDR. This contract adds stability to the Stack vSPD algorithm by hedging against volatile prices and ensuring that Tiwai's demand is always met.

We assume in this model that the future demand is not known. A projected demand is used to plan the dispatch schedule and estimate future prices. The projected demand for each trading period and node is calculated a priori from historical data from the years 2005-2009. The original plan was to use demand data from the CDS, but the data in the CDS had some inconsistencies with the demand data for the vSPD GDX files. Therefore, the projected demand used in these experiments comes from the *i_TradePeriodNodeDemand* parameter in the vSPD GDX files. In order to project the demand data for each day, we stratified the historical data by season and day of week. For our projections we use time averaged demand across the stratified data. The process was made more difficult by the fact that the transmission network configuration varies over time. In order to compensate for this, a superset of all transmission nodes across the years 2005-2009 was collected. The demand data for each node and trading period was summed within each stratified sample. The summation of demand for each trading period and node was then divided by the number of times that the node was included in the transmission configuration.

We chose to use averaged demand because it is a simple method of projection and because demand projection is not the primary focus of this project. More advanced demand projection techniques may involve performing a regression method with factors such as temperature and day of week. After each agent has submitted their offers, the true demand for the period becomes known and the future demands are reestimated. This reestimation is perfomed by shifting all the future demands at each node by the difference between the projected demand and the actual demand for the current period at each node, e.g. if the projected demand at OTA2201 is projected to be 25 MW at trading period 1, but the actual demand was 30 MW, then all future demands at OTA2201 are shifted up by 5 MW. This method of shifting the demands is quite simple, but it performs adequately in our experiments.

We then solve vSPDR over all 48 periods using the offers calculated, subject to the projected and known demands. vSPDR finds the optimal dispatch across the transmission network subject to transmission constraints. Reserve is not handled in our vSPDR model. The primary reason for leaving out reserve was to ensure that enough generation would be dispatched to meet demand. Also, the historical reserve offers will not align with the offers we have calculated in our model, that is, large quantities of reserve and generation may be offered at the same station if we rely on the historical offers. A more involved model would calculate optimal reserve quantities and prices to offer into the market, but this is not the focus of this study.

Once the optimal dispatch has been calculated by vSPDR, we fix the generation for the current trading period for all stations except those stations on the Waikato and Waitaki river chains, which are allowed to rearrange their generation before being locked in, subject to block dispatch rules. We model the reallocation of generation for these river chains because each station may not be dispatched at a level that is desirable for optimal running of the river chain. This may occur due to vSPDR model not considering the river chain constraints when it finds the optimal dispatch. Regardless of whether a river chain is block dispatched, we allow non-generating water releases to be rearranged prior to being locked in. The shadow prices on the *ACNodeNetInjectionDefinition2* and *DCNodeNetInjection* constraints provide the nodal prices, $P_{n,t}$, for all trading periods. At this stage, the model rolls on to the next trading period iteration, where the prices are fed back to the hydro generators.

The prices produced by our Stack vSPD model, will be influenced by the non-zero hydro offer prices, therefore they are not comparable with the price produced by the Clairvoyant model. Therefore, if we want to compare these prices to the Clairvoyant model's prices, we need to re-solve using vSPDR. We do this after the Stack vSPD model has been solved for all 48 periods. We unfix all variables, set the upper bound on hydro generation to be equal to optimal quantities found by Stack vSPD. We do not set an upper bound on thermal generation, however, just in case there are any numerical precision errors and the model needs to exceed the optimal thermal generation marginally. We offer the hydro quantities in at zero price, and we offer the thermal quantities at their short-run marginal cost. This produces a set of prices that can be compared with our other market simulation models.

3.5.2.3 Rolling Central Model Rationale

Refer to Appendix A.4 for a detailed pseudocode description of the Rolling Central model's process.

The rolling central model provides a market simulation of a centrally planned real-time market structure, assuming uncertain knowledge of future demands, but perfect foresight for tributary inflows. In this centrally planned model, all generation is scheduled based on its cost. Just like the Clairvoyant model, the Rolling Central model is a linear program that schedules the hydro and thermal generation over the New Zealand Transmission network. However, instead of solving the Central model one single time, the rolling central model iterates over each trading period, $\bar{t}$, solving the vSPD Central model a single time at each iteration. When compared to the Clairvoyant model, the Rolling Central model can be used to quantify the inefficiency caused by uncertainty. Comparing the Rolling Central model with the Stack vSPD model, the Rolling Central model can be used to quantify the coordination inefficiency caused by decentralized hydro planning, since the Rolling Central model coordinates hydro scheduling across the time horizon. We do not extend the planning horizon each time we roll to the next trading period. This is done for simplicity, especially in terms of our GDX files, which are broken into daily data.

As with the Clairvoyant and Stack vSPD models, the power stations in the four major hydro schemes (Waikato, Waitaki, Clutha, and Manapouri) and the major thermal and non-embedded cogeneration (Huntly, Otahuhu, Stratford, Whirinaki, Southdown, Te Rapa) are the stations that we allow to offer into the market. All other generation, which is primarily small hydro, embedded generation, and embedded cogeneration are offered at their historical levels at an offer price of zero. Wind generation is already subtracted from the demand values, therefore it does not need to be handled. We do not use the historical generation offers for our offering generators. This is because the historical offers may have been strategic in nature and, therefore, do not align with the objectives of these experiments.

The thermal generators offer in five tranches of equal quantity, which sum up to the *ReserveGenerationMaximum* parameter defined under *i_TradePeriodOfferParameter*. Ideally, we would like to model the marginal thermal cost as a piecewise constant function, where an increasing marginal cost approximates the decrease in marginal efficiency of the thermal generators as output in increased. However, we do not have data on how the marginal thermal costs change with power output. We do, however, model the cost of operations and maintenance costs in our thermal cost functions. Therefore, the offer price for thermal generation is set to the product of the station's heat rate and the seasonal price of the fuel that the station burns plus the marginal operational and maintenance cost. Hydro generation is offered in a single tranche zero-priced quantity equal to the stations maximum generation, defined by the *ReserveGenerationMaximum* parameter. As with the Clairvoyant and Stack vSPD models, we do not model reserve in the Rolling Central Model. This is due to historical reserve offers being coordinated with historical generation offers. Since we do not use historical generation offers, we leave out the historical reserve offers.

Since vSPD has a set containing the hydro stations, *i_offer*, or S^H in our formulation, but no sets corresponding to the lakes and junctions, we need to introduce a set for these components. We introduce a set, H, that includes all the stations, reservoirs, and junctions. The generation for the stations in set H is then mapped to the generation for the hydro stations in set *i_offer*. In hindsight, it could be simpler for H to be a set of reservoirs and junctions only, and map the stations in *i_offer* to their adjacent reservoirs and junctions. However, the set definition that we implemented was chosen because it was compatible with the way that the River Chain Model was formulated prior to integration with vSPD. In vSPD, a variable, *HydroGeneration*, is introduced to model the generation corresponding to each station in H over each time period and this generation is mapped to the *Generation* variable native to vSPD in order to link the river chain formulation with vSPDR.

We assume in this model that the future demand is not known. A set of projected demands is used to schedule the generation going forward. The demand projection model we use for the Rolling Central Model is the same one implemented by the vSPD Stack model. For more information on the demand projection method, refer to 3.5.2.2.

As with the Stack vSPD model and the Clairvoyant model, we include the Tiwai-Meridian contract for continuous generation of 572 MW. The primary purpose for including this contract in our dispatch models is that it makes the Stack vSPD model more stable by hedging against volatile prices. For more information on this contract, refer to section 3.5.2.2. The total generation on the Waikato and Clutha river chains are also restricted by the market node constraints (section 3.5.1).

The Rolling Central model uses piecewise water value coefficients calculated by the Clairvoyant solution. For details on the calculation of these coefficients, see section 3.5.2.1. The cost of not meeting the target reservoir levels and end of day in-transit flows is added onto the objective function for the vSPD Central model. By adding this term into the objective function, and allowing the final reservoir volume and flows to vary from the target levels allows the central planner to use water more wisely.

For example, if, late in the day, a demand eventuates that is far higher than expected, the planner can use water to shave prices in this period at the expense of meeting the final reservoir volume, if it expected to be profitable in the long run. Alternately, if a low demand becomes known later in the day, the planner can choose to hold onto the water if it is more profitable to do so.

Once the demand is known for the current trading period, and future demands are reestimated across the planning horizon, we solve the vSPD Central model over the planning horizon, subject to the projected and known demands. vSPD Central finds the optimal dispatch, water releases, and reservoir volumes across the planning horizon. Unlike the Stack vSPD model, we do not allow the agents with hydro generation to rearrange the dispatch, since it is already coordinated optimally. At each trading period iteration, vSPD Central is solved. We fix the optimal generation, water releases, and transmission flows for the current period and roll forward to the next period.

As with the Clairvoyant model, prices produced by the Rolling Central model are influenced by the presence of water transfers between periods. Therefore, if we want to compare these prices to the Stack vSPD model, we need to re-solve using vSPDR. We do this after the Rolling Central model has been solved for all 48 periods. We unfix all variables, set the upper bound on hydro generation to be equal to optimal quantities found by RC. We do not set an upper bound on thermal generation, however, just in case there are any numerical precision errors and the model needs to exceed the optimal thermal generation marginally. We offer these quantities in at the same offer prices used by RC. This produces a set of prices that can be compared with our other market simulation models.

Chapter 4

Experimental Results

Figures 4.1 and 4.2 show the results of our first experiment. In this experiment, the Historical, Clairvoyant and Stack vSPD models are solved over approximately one year of data. We break the costs into two categories, fuel cost and infeasibility cost. The fuel cost is calculated as the sum of cost of fuel burnt, thermal operational and maintenance costs, and the costs (or savings) associated with using more (or less) water than the targets dictate. The infeasibility costs are the cost of violating particular vSPD constraints. The vSPD constraint penalties are outlined in Figure 3.3. The monetary penalty applied are the CVP (Constraint Violation Price) values provided by Transpower [2]. However, the CVP values used for failure to meet demand vary from New Zealand's Value of Lost Load (VoLL). The VoLL used by Philpott and Guan is $10,000/MWh [26], whereas the CVP value for deficit bus generation is $100,000. Due to the arbitrary nature of the cost involved with constraint violation, we will focus more on the difference in fuel cost between our models.

	Historical	Clairvoyant	Stack vSPD
Fuel Cost	$ 1,600,441.89	$ 1,401,375.33	$1,572,947.53
Infeasibility Cost	$ 34,310.03	$ 4,605.11	$ 55,497.25
Total Cost	$ 1,634,751.92	$ 1,405,980.44	$ 1,628,544.78

Figure 4.1: Breakdown of Costs for Historical, Clairvoyant and Stack vSPD models. Cost displayed is average daily cost from 16 July 2008 until 20 July 2009. All costs in 2013 NZD.

	(Hist−Clair)/Hist	(Hist−Stack)/Hist	(Stack−Clair)/Stack
Fuel Cost	12.4%	1.72%	10.9%
Infeasibility Cost	86.6%	-62.0%	91.7%
Total	14.0%	0.380%	13.6%

Figure 4.2: Percentage Savings compared between each of the three models solved. Results are from 16 July 2008 to 20 July 2009.

Historical vs. Clairvoyant

The first observation we make is the difference between the Historical model and the Clairvoyant model. The difference between these models provides an estimate of the total inefficiency in New Zealand's market. The Clairvoyant model produced fuel cost savings of 12.4% in comparison to what actually happened in the market. Including the 86.6% savings on constraint violation costs, the total savings for the Clairvoyant model were 14.0%. Therefore, we estimate that the total inefficiency in the NZEM, for the period of time studied, is between 12.4% and 14%.

Stack vSPD vs. Clairvoyant

The difference between the Stack vSPD model and the Clairvoyant model provides us with an estimate of the loss of efficiency due to demand uncertainty plus loss of coordination. The Clairvoyant model produced fuel cost savings of 10.9% in comparison to our Stack vSPD model. Including the 91.7% savings on constraint violation costs, the total savings for the Clairvoyant model were 13.6%. Therefore, we estimate that the ineffiency due to demand uncertainty and loss of coordination in the NZEM, for the period of time studied, is between 10.9% and 13.6%.

Historical vs. Stack vSPD

The difference between the Historical model and the Stack vSPD model provides us with an estimate of the loss of efficiency due to other factors, including exercise of market power, risk effects, and use of reserves. The Stack vSPD model produced fuel cost savings of 1.72% in comparison to what actually happened in the market. However, the Stack vSPD model incurred 62% higher total constraint violation costs, resulting in total savings of 0.380% for the Stack vSPD model. Therefore, we estimate that the inefficiency due to residual effects in the NZEM, for the period of time studied, is between 1.72% and 0.380%. From the fuel cost savings figure, we estimate that market power and other residual effects account for at most 14.0% of inefficiency in New Zealand's electricity market. This means that the remaining 86% can be accounted for by demand uncertainty and loss of coordination.

The difference in hydro production between these three models is interesting to us.

Stack vSPD vs. Clairvoyant

These two models have the same target reservoir volumes and target end of day in-transit flows. The Stack vSPD model is not required to meet these targets, but failing to meet targets will incur either a penalty or savings. The amount of hydro generation produced in the Stack vSPD model was very close to the amount used by the Clairvoyant model. However, the Stack vSPD model incurred a high penalty for failing to meet the targeted volumes and in-transit flows. This figure accounts for 8.2% of the total fuel cost for the Stack vSPD model. Since more water was required to achieve the same amount of hydro generation, the productive efficiency of the hydro stations is reduced.

Historical vs. Clairvoyant

> The target reservoir volumes and target end of day in-transit flows for the Clairvoyant model come from the Hydro Boundary Condition model, which is based on what happened in history. Therefore, the boundary conditions for the Clairvoyant model are approximately equal to the those of the historical model. We observe that the amount of hydro generation used by the Historical model is 5.4% less than the amount used by the Clairvoyant model, meaning the productive efficiency of the hydro generation is higher for the Clairvoyant model.

We observe that there is a decreased productive efficiency for hydro stations for both the Stack vSPD and the Historical models. This loss of productive efficiency may be due to a combination of lack of coordination, the rolling dispatch mechanism, and demand uncertainty.

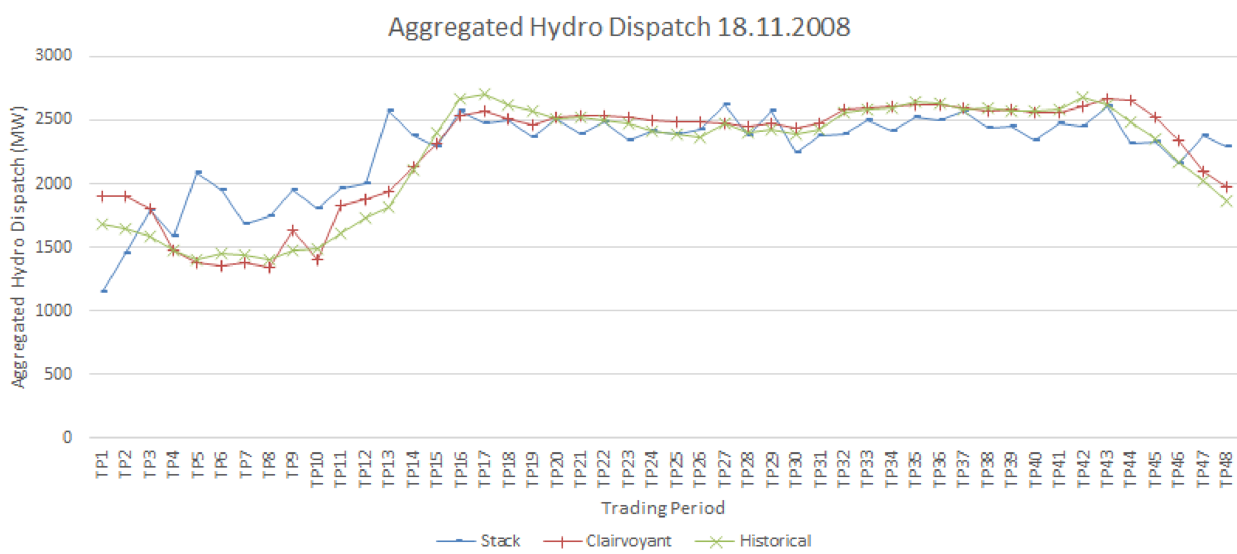

Figure 4.3: New Zealand Aggregated Hydro Dispatch for Historical, Clairvoyant and Stack vSPD models for November 18, 2008.

In Figure 4.3, we see the aggregated hydro production for the Historical, Clairvoyant, and Stack vSPD models. We see that the Historical and Clairvoyant models tend to produce a smoother solution than the Stack vSPD model. The historical offers do not vary much within each day, allowing a smooth transition from period to period. However, the current and future offers for the Stack vSPD model are updated every trading period, in response to changes in price. The drawback to this oscillation is that water that would ideally be allocated to peak periods may be consumed in off-peak periods.

In our first experiment we calculated the loss of efficiency due to the sum of the effects of demand uncertainty and loss of coordination. We want to separate the extent to which each of these factors contribute to market inefficiency. Therefore, we conducted a second experiment including the Rolling Central model to isolate each of these factors. Figures 4.4 and 4.5 show the results of our second experiment. In this experiment, the Historical, Clairvoyant, Stack vSPD, and Rolling Central models are solved over two months of data. In addition to comparisons including the Rolling Central model, we redo the comparisons from the first experiment on the two month subset. We do this in order to estimate the proportion of inefficiency caused by demand uncertainty and by loss of coordination.

	Historical	Clairvoyant	Stack vSPD	Rolling Central
Fuel Cost	$ 1,837,724.095	$ 1,631,029.74	$ 1,818,094.29	$ 1,636,496.61
Infeasibility Cost	$ 9,586.61	$ 151.34	$ 151.34	$ 151.34
Total Cost	$ 1,847,310.70	$ 1,631,181.07	$ 1,818,245.63	$ 1,636,647.94

Figure 4.4: Breakdown of Costs for Historical, Clairvoyant, Stack vSPD, and Rolling Central models. Cost displayed is average daily cost for the months of February 2009 and June 2009. All costs in 2013 NZD.

	(Hist−Clair)/Hist	(Hist−Stack)/ Hist	(Stack−Clair)/Stack	(Stack−RC)/Stack	(RC−Clair)/RC
Fuel Cost	11.2%	1.07%	10.3%	9.99%	0.334%
Infeasibility Cost	98.4%	98.4%	0.0%	0.0%	0.0 %
Total	11.7%	1.57%	10.3%	9.99%	0.334%

Figure 4.5: Percentage Savings compared between each of the three models solved. Results are from the months of February 2009 and June 2009.

Historical vs. Clairvoyant

The first observation we make is the difference between the Historical model and the Clairvoyant model for this subset of data. The difference between these models provides an estimate of the total inefficiency in New Zealand's market. The Clairvoyant model produced fuel cost savings of 11.2% in comparison to what actually happened in the market. Including the 98.4% saving on constraint violation costs, the total savings for the Clairvoyant model were 11.7 %. Therefore, we estimate that the total inefficiency in the NZEM, for the period of time studied, is between 11.2% and 11.7%.

Historical vs. Stack vSPD

The difference between the Historical model and the Stack vSPD model provides us with an estimate of the loss of efficiency due to other factors, including exercise of market power. The Stack vSPD model produced fuel cost savings of 1.07% in comparison to what actually happened in the market. Including the 98.4% saving on constraint violation costs, the total savings for the Stack vSPD model were 1.57%. Therefore, we estimate that the upper bound on ineffiency due to Market Power in the NZEM, for the period of time studied, is between 1.07% and 1.57%.

Stack vSPD vs. Clairvoyant

The difference between the Stack vSPD model and the Clairvoyant model provides us with an estimate of the loss of efficiency due to coordination loss and demand uncertainty. The Clairvoyant model produced fuel cost savings of 10.3% in comparison to the Stack vSPD model. Because there was no difference in the cost of constraint violation, the total loss of efficiency due to loss of coordination and demand uncertainty, for the period of time studied, is 9.99%.

Stack vSPD vs. Rolling Central

The difference between the Stack vSPD model and the Rolling Central model provides us with an estimate of the loss of efficiency due to coordination loss. The Rolling Central model produced fuel cost savings of 9.99% in comparison to the Stack vSPD model. Because there was no difference in the cost of constraint violation, the total loss of efficiency due to loss of coordination, for the period of time studied, is 9.99%.

Rolling Central vs. Clairvoyant

The difference between the Rolling Central model and the Clairvoyant model provides us with an estimate of the loss of efficiency due to uncertainty of demand. The Clairvoyant model produced fuel cost savings of 0.334% in comparison to the Rolling Central model. Because there was no difference in the cost of constraint violation, the total loss of efficiency due to demand uncertainty, for the period of time studied, is between 0.334%.

Chapter 5

Discussion and Conclusions

- In our first experiment, we estimated the total inefficiency in the New Zealand electricity market, by simulating over a year of data. This figure was estimated to be 12.4%, in terms of fuel cost. Our second experiment, which was simulated over only two months, estimated the inefficiency to be 11.2%. Therefore, we believe that these two months are reasonably representative of the larger data set.

- From the results of our second experiment, we found that our estimate of the impact of demand uncertainty on inefficiency was very low. Our estimate of the inefficiency due to demand uncertainty is 0.334%. The demand forecasting method we used was unsophisticated. Therefore, we believe that with a more complex forecasting method, it is likely that lower estimates would be obtained. Additionally, electricity is traded through bilateral contracts in New Zealand's electricity market. However, information on these contracts is not publicily available, except for the Meridian-Tiwai contract. Therefore, we only include the Tiwai-Meridian contract in our models. Including these contracts would lessen the impact of demand uncertainty in our models.

- We found that coordination loss was the major source of inefficiency in the New Zealand electricity market. In our second experiment, we estimated the inefficiency due to loss of coordination to be approximately 10%. From this result, we can conclude that poor pricing forecasts can lead to poor coordination of generation, even when generators are acting as pricetakers.

- We estimated the inefficiency due to residual factors to be 1.57%, in terms of fuel cost. These other factors may include exercise of market power, the effects of risk, or use of reserve. Philpott and Guan [27] estimated the short-term inefficiencies in the market to be 10%. These inefficiencies are not solely attributable to market power.

- A recurring issue in the development of the Stack vSPD model was the lack of smooth generation from one trading period to the next. This behaviour has negative effects on peak shaving, leading to reduced productive efficiency. If a more stable algorithm could be developed, then improved estimates on the inefficiency due to market power and loss of coordination could be obtained. A model with improved peak shaving may show that the inefficiency due to market power is higher and the inefficiency due to loss of coordination is lower than we have estimated.

- The unsteady behaviour exhibited in our Stack vSPD shows that if generators rely too heavily on price signals to guide their offers, then the amout of dispatched hydro generation will fluctuate significantly from one trading period to the next.

- In order to obtain our estimate on the inefficiency due to market power, we had to assume that demand uncertainty in the Stack vSPD model and the historical model were equal. However, our demand forecasting method is not as sophisticated as the mechanism that is used by the system operator. Therefore, the demand uncertainty in our Stack vSPD models is likely to be higher than actually occurs in the market. With a better demand projection method, the Stack vSPD model would likely produce cheaper solutions, resulting in a higher estimate of inefficiency due to market power and a lower estimate of inefficiency due to lack of coordination.

Chapter 6

Future Works

This paper could be criticized for implementing a simple demand forecasting method. A more detailed study of uncertainty in the New Zealand electricity market would include a more complex demand forecasting method, similar to that used by Transpower. However, we found that the effect of demand uncertainty was fairly insignificant despite our simple demand projection method.

An issue that was common in our experiments was the fluctuation in hydro usage from one trading period to the next. This instability is detrimental to productive efficiency. In future attempts at modelling the behaviour of the large generators, special attention should be paid toward producing a more steady supply of hydro generation. This could be achieved in a number of manners. The ramping rates of the hydro stations could be restricted. This would prevent the major hydro generators from deviating too far from the previous period's production. Another method would be to implement contracts ensuring that each major hydro generator produces above some contracted generation level. As mentioned earlier, the terms for existing generation contracts are not publicly available. However, experiments could be performed at various levels of contracted generation, in a similar manner to Scott and Read [39].

Reserves play an important role in the New Zealand electricity market. Due to time constraints, we did not include the offering of reserve in our Clairvoyant, Stack vSPD, or Rolling Central models. vSPD has the framework for offering of reserve and interruptible load. Therefore, this study could be extended to investigate inefficiency when reserve procurement is included in the system. Additionally, various reserve offering strategies could be simulated for the purpose of designing efficient strategies.

This study has begun to assess the impact that a day-ahead market would have on the New Zealand electricity market. It would be useful to develop a model to simulate how a day-ahead market would work in New Zealand. Such a project would involve designing a market structure that is optimised for New Zealand's unique system, so as to incent competitive behaviour and maximize productive, allocative, and dynamic efficiency. The day-ahead model could be compared to historical data to estimate the gain (or loss) in efficiency that could be obtained by instituting a day-ahead market in New Zealand.

Appendices

Appendix A

Pseudocode

A.1 Pseudocode for Simple Pricetaker Model

A.1.1 Sets and Mappings used in Pseudocode

- T the set of time periods
- H the set of Hydro Stations,Reservoirs and Junctions
- L the subset of H for Reservoirs only
- S the set of all Stations
- S^T the set of Thermal Stations
- S^H the set of Hydro Stations
- N the set of transmission nodes
- S the set of all stations

- C the set of River Chains
- A the set of River Chains with block dispatch
- B the set of River Chains without block dispatch
- N^c a single transmission node corresponding to river chain $c \in C$
- H^C the set of all stations,reservoirs, and junctions corresponding to river chain $c \in C$
- S^C the set of all stations to river chain $c \in C$

A.1.2 Variables used in Pseudocode

- $X_{s,t}$ is the generation of station $s \in S$ at trading period $t \in T$
- $\omega_{\hat{h},\check{h},t}$ is the non-generating flow between from reservoir $\hat{h} \in H$ to reservoir $\check{h} \in H$ at trading period $t \in T$
- $X^{\Sigma}_{c,t}$ is the sum of generation at river chain $c \in C$ for time period $t \in T$. When fixed, this variable enforces the block dispatch constraint.

A.1.3 Parameters Used in Pseudocode

- $Q_{s,t}$ is the quantity offered at station $s \in S$ at trading period $t \in T$
- $D_{n,t}$ is the actual demand at node n$\in N$ at trading period $t \in T$
- $\overline{D}_{n,t}$ is the projected demand at node $n \in N$ at trading period $t \in T$
- $P_{n,t}$ is the forecast electricity price at node $n \in N$ at trading period $t \in T$
- $P^{Y}_{n,t}$ is the energy price from the previous day at node$n \in N$ at trading period $t \in T$

- $X^*_{s,t}$ is the optimal generation of station $s \in S$ at trading period $t \in T$

- $\omega^*_{\hat{h},\check{h},t}$ is the optimal non-generating flow between from reservoir $\hat{h} \in H$ to reservoir $\check{h} \in H$ at trading period $t \in T$

A.1.4 Pseudocode

Forecast Prices for day set to yesterday's prices: $P_{n,t} = P^Y_{n,t}$ $\forall t \in T, \forall n \in N$

Loop over time periods, $\bar{t}$. $\bar{t}$ is always the current time period.

for $\bar{t} = 1$ to $|T|$

Loop over river chains for each $c \in C$

Solve Offer Problem for River Chain c, optimised using the forecast prices at node N^c:

$max \sum^{s \in S^c} \sum^{t \in T} P_{N^c,t} \times X_{s,t}$

s.t. Conservation of Mass Constraints, Reservoir Volume Limits, Ramping Constraints, Spill Limits, Generating Flow Limits, Generation Limits, Block Dispatch Constraint. Yields new $X^*_{s,t}$ and $\omega^*_{\hat{h},\check{h},t} \forall s \in S^c, \forall t \in T, \forall \check{h}, \hat{h} \in H$

Dispatch from model solved gives the offers for all time periods coming from River Chain c

$Q_{s,t} = X^*_{s,t}$ $\forall s \in S^c, \forall t \in T$

next c

Fix water releases from previous period

fix $\omega_{\hat{h},\check{h},\bar{t}-1} = \omega^*_{\hat{h},\check{h},\bar{t}-1}$ $\forall \check{h}, \hat{h} \in H$

Loop over river chains with block dispatch

for each $a \in A$

Fix Hydro Dispatch and non-generating flow from the previous time period for river chains with block dispatch:

if $\bar{t} > 1$

fix$X_{s,\bar{t}-1} = X^*_{s,\bar{t}-1}$ $\forall s \in S^A$

end if

next a

Nodal Demand for Period $\bar{t}$, $D_{n,\bar{t}}$ becomes known for all $n \in N$. Projected demands, $\overline{D}_{n,t}$ are reestimated by shifting $\overline{D}_{n,t}$ by $D_{n,\bar{t}} -, \overline{D}_{n,\bar{t}}$ for each $t > \bar{t}$ and $n \in N$

Set Offers for Thermal Stations to be maximum generation and Hydro Offer Prices are set to zero.

Solve Scheduling, Pricing and Dispatch problem minimizing thermal costs: s.t. Meet Nodal Demand, Transmission and Voltage Angle Constraints, Block Dispatch Constraint, Thermal and Hydro Ramping Constraints, Station Dispatch does not exceed offer.

Yields new $X^*_{s,t} \forall s \in S, \forall t \in T$

Calculate New forecast Prices, $P_{n,t}$, the dual variables for the "Meet Nodal Demand" constraint, in $\$/MWh$.

Loop over river chains with block dispatch for each $a \in A$

Fix the sum of dispatch for river chain a for period $\bar{t}$:

Fix $X^{\Sigma}_{a,\bar{t}} = \sum^{s \in S^A} X^{*}_{s,\bar{t}}$

next a

- Loop over river chains without block dispatch

for each $b \in B$

Fix the dispatch for period $\bar{t}$:

Fix $X_{s,\bar{t}} = X^{*}_{s,\bar{t}}$ $\forall s \in S^b$

next b

Fix Thermal Dispatch for period $\bar{t}$

Fix $X_{s,\bar{t}} = X^{*}_{s,\bar{t}}$ $\forall s \in S^T$

next $\bar{t}$

A.2 Clairvoyant Model Pseudocode

A.2.1 Sets and Mappings used in Pseudocode

- T the set of time periods
- H the set of Hydro Stations,Reservoirs and Junctions
- S the set of all Stations
- L the subset of H for Reservoirs only

- L^F the subset of H for Reservoirs only corresponding to agent $f \in F$
- S^T the set of Thermal Stations
- S^H the set of Hydro Stations.
- S the set of all stations
- S^0 subset of S containing non-offering stations
- N the set of transmission nodes
- R the five tranches for hydro offers
- C the set of River Chains
- C^F the set of River Chains corresponding to agent $f \in F$

A.2.2 Variables used in Pseudocode

- $X^B_{r,s,t}$ is the generation of station $s \in S$ at trading period $t \in T$ for Tranche $r \in R$
- $\widehat{\delta}_l$ is the surplus above the target reservoir level for each reservoir $l \in L$
- $\breve{\delta}_l$ is the deficit below the target reservoir level for each reservoir $l \in L$
- $\widehat{\delta}^{\omega}_h$ is the surplus above the target end of day in-transit volume for hydro node $h \in H$
- $\breve{\delta}^{\omega}_h$ is the deficit below the target target end of day in-transit volume for hydro node $h \in H$

A.2.3 Parameters used in Pseudocode

- $Q_{r,s,t}$ is the quantity offered at station $s \in S$ at trading period $t \in T$ corresponding to tranche $r \in R$

- $\widehat{P}_{r,s,t}$ is the price offered at station $s \in S$ at trading period $t \in T$ corresponding to tranche $r \in R$
- $D_{n,t}$ is the actual demand at node n$\in N$ at trading period $t \in T$
- $U_{s,t}$ is the maximum generation at station s $\in S$, at trading period $t \in T$, subject to generator derating
- $X^*_{s,t}$ is the optimal generation of station $s \in S$ at trading period $t \in T$
- α is the percentage of base fuel cost by which each tranches fuel cost exceeds the previous tranche
- $\widehat{c}_s$ is the base marginal fuel consumption cost for station $s \in S^T$. This is equal to the heat rate multiplied by the wholesale fuel cost.
- $\breve{c}_s$ is the marginal operations and maintenance cost for station $s \in S^T$.
- $X^{B*}_{r,s,t}$ is the optimal generation of station $s \in S$ at trading period $t \in T$ for Tranche $r \in R$
- $X^H_{s,t}$ historical generation for station $s \in S^0$ and $t \in T$
- γ_l is the cost coefficient corresponding to having a shortage of water relative to target reservoir levels for each reservoir $l \in L$
- β_l is the cost coefficient corresponding to exceeding target reservoir levels for each reservoir $l \in L$
- γ^ω_h is the cost coefficient corresponding to having a shortage of water relative to target end of day in-transit volume for hydro node $h \in H$
- β^ω_h is the cost coefficient corresponding to exceeding target end of day in-transit volume for hydro node $h \in H$
- γ^{lim} is some upper bound on the starting value for γ and γ^ω

- β^{lim} is some lower bound on the starting value for β and β^{ω}
- $\widehat{\delta}_l^{min}$ is the minimum possible surplus above target reservoir level for each reservoir $l \in L$
- $\breve{\delta}_l^{min}$ is the minimum possible deficit below target reservoir level for each reservoir $l \in L$
- $\widehat{\delta}_l^{\omega,min}$ is the minimum possible surplus abovetarget end of day in-transit flows for each hydro nod $h \in H$
- $\breve{\delta}_l^{\omega,min}$ is the minimum possible deficit below target end of day in-transit flows for each hydro node $h \in H$
- δ is the aggregated absolute total deviation from target reservoir levels across all reservoirs
- δ^{min} is the aggregated absolute total deviation from target reservoir levels that minimizes the penalty cost of deviation from target levels
- δ^{ω} is the aggregated absolute total deviation from target end of day in-transit volumes across all hydro nodes
- δ^{min} is the aggregated absolute total deviation from target end of day in-transit volumes that minimizes the penalty cost of deviation from target in-transit volumes
- θ is the linear factor for scaling γ_l, γ_h^{ω}, $beta_l$, and β_h^{ω} after each solve
- ψ is a quadratic factor for scalingγ_l, γ_h^{ω}, $beta_l$, and β_h^{ω} after each solve
- c^{MAX} is the maximum fuel cost out of all stations in the system

A.2.4 Pseudocode

Set the offers for the thermal generators

$$Q_{r,s,t} = U_{s,t} \qquad r = 1 \forall t \in T, \forall s \in S^T$$

$$\widehat{P}_{r,s,t} = \widehat{c}_s + \check{c}_s \qquad r = 1, \forall t \in T, \forall s \in S^T$$

$$Q_{r,s,t} = 0 \qquad r > 1 \forall t \in T, \forall s \in S^T$$

Set quantity and price for all hydro tranches to zero

$$Q_{r,s,t} = 0 \qquad \forall r \in R \forall t \in T, \forall s \in S^H$$

$$\widehat{P}_{r,s,t} = 0 \qquad \forall r \in R, \forall t \in T, \forall s \in S^H$$

Set offer quantity for tranche 1 to be the maximum generation for station

$$Q_{r,s,t} = U_{s,t} \qquad \forall s \in S^H, \forall t \in T, r = 1$$

Set quantity and price to be zero for all nonoffering generators $Q_{r,s,t} = 0 \qquad \forall r \in R \forall t \in T, \forall s \in S^0$

$$\widehat{P}_{r,s,t} = 0 \qquad \forall r \in R, \forall t \in T, \forall s \in S^0$$

Offer in historical generation for non-offering generators

$$Q_{r,s,t} = X^H_{s,t} \qquad \forall s \in S^0, \forall t \in T, r = 1$$

Set γ and γ^ω to be very high and β and β^ω to be very low

$$\beta_l = -1 \times 10^4 \qquad \forall l \in L$$

$$\gamma_l = 1 \times 10^4 \qquad \forall l \in L$$

$$\beta^\omega_h = -9 \times 10^3 \qquad \forall h \in H$$

$$\gamma^\omega_h = 9 \times 10^3 \qquad \forall h \in H$$

solve vSPD Central minimizing sum of fuel costs, penalty costs, and water penalty costs. Yields new $\widehat{\delta}_l$, $\check{\delta}_l$, $\widehat{\delta}^\omega_h$, and $\check{\delta}^\omega_h$

Set γ_l, β_l, γ^ω_h, and β^ω_h, to be equal to the shadow price on initial reservoir level limit

Set the deviation levels corresponding to the solve that minimizes deviation. In most cases, these will equal zero, but there is a chance that the boundary conditions do not line up perfectly.

$\widehat{\delta}_l^{min} = \widehat{\delta}_l,$

$\check{\delta}_l^{min} = \check{\delta}_l$

$\widehat{\delta}_h^{\omega,min} = \widehat{\delta}_h^{\omega},$

$\check{\delta}_h^{\omega,min} = \check{\delta}_h^{\omega}$

Set the aggregated deviation corresponding to the minimum deviation from target levels

$\delta^{min} = \sum^{l \in L} \check{\delta}_l^{min} + \widehat{\delta}_l^{min}$

Set the aggregated deviation corresponding to the minimum deviation from target intransit volumes

$\delta^{\omega,min} = \sum^{h \in H} \check{\delta}_h^{\omega,min} + \widehat{\delta}_h^{\omega,min}$

Loop over each reservoir. If the γ (γ^{ω}) are unrealistically high or the β (β^{ω}) are unrealistically low, then set estimate the value to be $\$0.02/m^3$. Exceeding these bounds will often coincide with $\check{\delta}_l^{min}$ ($\check{\delta}_h^{\omega,min}$) or $\widehat{\delta}_l^{min}(\widehat{\delta}_h^{\omega,min})$ not equalling zero.

for each $l \in L$

    if $\gamma_l > \gamma_l^{lim}$

        $\gamma_l = 0.2$

    end if

    if $\beta_l < \beta_l^{lim}$

        $\beta_l = 0.2$

end if

$\gamma_l = \gamma_l * (1 + \theta)$

$\beta_l = \beta_l * (1 - \theta)$

next l

for each $h \in H$

if $\gamma_h^{\omega} > \gamma_h^{\omega,lim}$

$\gamma_h^{\omega} = 0.2$

end if

if $\beta_h^{\omega} < \beta_h^{\omega,lim}$

$\beta_h^{\omega} = 0.2$

end if

$\gamma_h^{\omega} = \gamma_h^{\omega} * (1 + \theta)$

$\beta_h^{\omega} = \beta_h^{\omega} * (1 - \theta)$

next h

Set the aggregated absolute deviation from target levels to be +inf

$\delta = +inf$

$\delta^{\omega} = +inf$

Set loop index to zero

$i = 0$

Iteratively change the β_l (β_h^ω) and γ_l (γ_h^ω)values until the deviation from target levels converges to its minimum possible deviation.

We use the quadratic update term to accelerate conversion towards the appropriate γ_l and β_l values.

while $\delta - \delta^{min} > eps$ and $\delta^\omega - \delta^{\omega,min} > eps$

solve vSPD Central minimizing sum of fuel costs, penalty costs, and water penalty costs. Yields new $\widehat{\delta}_l$, $\check{\delta}_l$, $\widehat{\delta}_h^\omega$, $\check{\delta}_h^\omega$, and $X_{r,s,t}^{*B}$

$\delta = \sum^{l \in L} \check{\delta}_l + \widehat{\delta}_l$

$\delta^\omega = \sum^{h \in H} \check{\delta}_h^\omega + \widehat{\delta}_h^\omega$

for each $l \in L$

If the surplus on reservoir l's target level exceeds the minimum possible surplus, then adjust β_l.

if $\widehat{\delta}_l^{min} - \widehat{\delta}_l > eps$

$\beta_l = \beta_l * (1 - \theta) - i^2\psi$

end if

If the deficit on reservoir l's target level exceeds the minimum possible deficit, then adjust γ_l.

if $\check{\delta}_l^{min} - \check{\delta}_l > eps$

$\gamma_l = \gamma_l * (1 + \theta) + i^2\psi$

end if

next l

for each $h \in H$

If the surplus on hydro node h's target in-transit volume exceeds the minimum possible surplus, then adjust β_h^ω.

if $\widehat{\delta}_h^{\omega,min} - \widehat{\delta}_h^\omega > eps$

$\beta_h^\omega = \beta_h^\omega * (1 - \theta) - i^2\psi$

end if

If the deficit on hydro node h's target in-transit volume exceeds the minimum possible deficit, then adjust γ_h^ω.

if $\breve{\delta}_h^{\omega,min} - \breve{\delta}_h^\omega > eps$

$\gamma_h^\omega = \gamma_h^\omega * (1 + \theta) + i^2\psi$

end if

next h

$i = i + 1$

loop

Now, in order to produce prices comparable to the rolling solutions, we set the hydro offer quantities to be equal to the optimal dispatch from vSPD Central's most recent solve, and keep all non-hydro offers the same. The offer price is already zero, so this does not need to change

$$Q_{r,s,t} = X_{r,s,t}^{B*} \qquad \forall s \in S^H, \forall t \in T$$

solve vSPDR minimizing sum of fuel costs and penalty costs. Yields an unchanged $X_{h,t}^{B*}$ and new $P_{n,t}$, the nodal prices.

A.3 Stack vSPD Pseudocode

A.3.1 Sets and Mappings used in Pseudocode

- T the set of time periods
- H the set of Hydro Stations,Reservoirs and Junctions
- L the subset of H for Reservoirs only
- F the set of all Firms or Agents
- S the set of all stations
- S^T the set of Thermal Stations
- S^H the set of Hydro Stations.
- S^0 subset of S containing non-offering stations
- N the set of transmission nodes
- R the five tranches for hydro offers
- C the set of River Chains
- C^F the set of River Chains corresponding to agent $f \in F$
- N^c a single transmission node corresponding to river chain $c \in C$
- H^C the set of all stations,reservoirs, and junctions corresponding to river chain $c \in C$
- S^C the set of all stations to river chain $c \in C$

- H^F the set of all stations,reservoirs, and junctions corresponding agent $f \in F$
- H^F the set of all station corresponding to agent $f \in F$
- N^h a single transmission node corresponding to hydro station $h \in H$. All stations on the same river chain correspond to a single node.
- A the set of River Chains with block dispatch
- B the set of River Chains without block dispatch
- I the set of price distribution intervals

A.3.2 Variables used in Pseudocode

- $X^B_{r,s,t}$ is the generation of station $s \in S$ at trading period $t \in T$ for Tranche $r \in R$
- $\omega_{\hat{h},\check{h},t}$ is the non-generating flow between from reservoir $\hat{h} \in H$ to reservoir $\check{h} \in H$ at trading period $t \in T$
- $X^{\Sigma}_{c,t}$ is the sum of generation at river chain $c \in C$ for time period $t \in T$. When fixed, this variable enforces the block dispatch constraint.

A.3.3 Parameters used in Pseudocode

- $Q_{r,s,t}$ is the quantity offered at station $s \in S$ at trading period $t \in T$ corresponding to tranche $r \in R$
- $\widehat{P}_{r,s,t}$ is the price offered at station $h \in S$ at trading period $t \in T$ corresponding to tranche $r \in R$
- $\tilde{P}_{r,h,t}$ is the conditional expectation on price, at station $h \in S^H$ at trading period $t \in T$ corresponding to tranche $r \in R$

- $D_{n,t}$ is the actual demand at node n$\in N$ at trading period $t \in T$
- $\overline{D}_{n,t}$ is the projected demand at node $n \in N$ at trading period $t \in T$
- $P_{n,t}$ is the forecast electricity price at node $n \in N$ at trading period $t \in T$
- $\pi_{r,n,t}$ is an estimated electricity price at node $n \in N$ at trading period $t \in T$ corresponding to tranche $r \in R$
- $P^Y n, t$ is the energy price from the previous day at node$n \in N$ at trading period $t \in T$
- $U_{s,t}$ is the maximum generation at station s $\in S$ at trading period $t \in T$, subject to generator derating
- X_s^{fix} is the generation to be fixed at station s $\in S$
- $\omega_{\hat{h},\check{h}}^{fix}$ is the non-generating flow to be fixed between from reservoir $\hat{h} \in H$ to reservoir $\check{h} \in H$
- $X_{s,t}^*$ is the optimal generation of station $s \in S$ at trading period $t \in T$
- $X_{r,s,t}^{B*}$ is the optimal generation of station $s \in S$ at trading period $t \in T$ for Tranche $r \in R$
- $X_{s,t}^H$ historical generation for station $s \in S^0$ and $t \in T$
- $\omega_{\hat{h},\check{h},t}^*$ is the optimal non-generating flow between from reservoir $\hat{h} \in H$ to reservoir $\check{h} \in H$ at trading period $t \in T$
- α is the percentage of base fuel cost by which each tranches fuel cost exceeds the previous tranche
- $\widehat{c}_s$ is the base marginal fuel consumption cost for station $s \in S^T$. This is equal to the heat rate multiplied by the wholesale fuel cost.
- $\check{c}_s$ is the marginal operations and maintenance cost for station $s \in S^T$.

- $\widehat{\pi}_{n,r,i}$ is the price break corresponding to tranche $r \in R$ at node $n \in N$ given that the price for the previous period falls in price interval $i \in I$

- $\overline{\pi}_i$ is the upper bound on price for price interval $i \in I$. i.e. If $\pi_{n,i,t} \leq \overline{\pi}_i$ and $\pi_{n,i,t} > \overline{\pi}_{i-1}$ then $\pi_{n,i,t}$ falls in interval $i \in I$

- $\tilde{\pi}_{n,r,i}$ is the conditional expectation for a corresponding price break at node $n \in N$ corresponding to tranche $r \in R$, given that the price for the previous period falls in price interval $i \in I$

- $\Lambda_{i,n}$ predicts the price at node $n \in N$ given that the price 24 hours ago falls in interval $i \in I$

- c^{MAX} is the maximum fuel cost out of all stations in the system

A.3.4 Pseudocode

Loop over time periods, $\bar{t}$. $\bar{t}$ is always the current time period.

for $\bar{t} = 1$ to $|T|$

Set the thermal offer stack. Offer the full capacity at a single tranche at marginal fuel and maintenance cost

$$Q_{r,s,t} = U_{s,t} \qquad r = 1 \forall t \in T, \forall s \in S^T$$

$$\widehat{P}_{r,s,t} = \widehat{c}_s + \breve{c}_s \qquad r = 1, \forall t \in T, \forall s \in S^T$$

$$Q_{r,s,t} = 0 \qquad r > 1 \forall t \in T, \forall s \in S^T$$

Set quantity and price to be zero for all nonoffering generators $Q_{r,s,t} = 0 \quad \forall r \in R \forall t \in T, \forall s \in S^0$

$$\widehat{P}_{r,s,t} = 0 \qquad \forall r \in R, \forall t \in T, \forall s \in S^0$$

Offer in historical generation for non-offering generators $Qr,s,t = X^H s,t \forall s \in S^0, \forall t \in T, r = 1$

Reset all offer stacks to maximum generation for hydro generators. This prevents rearranged block dispatches from causing infeasibility.

$Q_{r,s,t} = U_{s,t}$ $\quad\forall t \in T, \forall s \in S^H, \forall r \in R$

if $\bar{t} = 1$ then

for $i = 1$ to $|I|$

for each $c \in C$

for $t = 2$ to $|T|$

Given that yesterdays price is in interval i, set the projected price to be $\Lambda_{i,n}$, where

$\overline{\pi}_0 = 0$

if $P^Y_{N^c,t} \in [\overline{\pi}_{i-1}, \overline{\pi}_i)$

$P_{N^c,t} = \Lambda_{i,N^c}$

end if

next t

next n

for each $c \in C$

Given the price from the previous day's final period is in interval i, where $\overline{\pi}_0 = 0$

if $P^Y_{N^c,'48'} \in [\overline{\pi}_{i-1}, \overline{\pi}_i)$

if $r = 1$

$\widehat{P}_{r,s,\bar{t}} = 0$ $\quad\forall s \in S^C, \forall r \in R$

else

Set the conditional expectation and offer prices, respectively, for current period.

$\tilde{P}_{r,s,\bar{t}} = \tilde{\pi}_{N^c,r,i}$ $\forall s \in S^C, \forall r \in R$

$\widehat{P}_{r,s,\bar{t}} = \widehat{\pi}_{N^c,r,i}$ $\forall s \in S^C, \forall r \in R$

end if

end if

next c

next i

else

for $i = 1$ to $|I|$

for each $c \in C$

Given the price from the previous period is in interval i, where $\overline{\pi}_0 = 0$

if $P_{N^c,\bar{t}-1} \in [\overline{\pi}_{i-1}, \overline{\pi}_i)$

Set the conditional expectation and offer prices, respectively, for current period.

$\tilde{P}_{r,s,\bar{t}} = \tilde{\pi}_{N^c,r,i}$ $\forall s \in S^C, \forall r \in R$

$\widehat{P}_{r,s,\bar{t}} = \widehat{\pi}_{N^c,r,i}$ $\forall s \in S^C, \forall r \in R$ $\tilde{P}_{r,s,\bar{t}} = 0.01$ $\forall s \in S^C, r = 1$

$\widehat{P}_{r,s,\bar{t}} = 0$ $\forall s \in S^C, r = 1$

end if

next c

next i

end if

Loop over tranches to generate offer stacks for current period and future periods.

for $r = 1$ to $|R|$

For each $f \in F$

$$P_{N^h,\bar{t}} = \tilde{P}_{r,N^h,\bar{t}} \qquad \forall s \in S^F$$

Solve River Chain Problem for agent f optimised using the relevant price estimate for each $s \in S^H$, $P_{N^h,t}$:

$max \sum^{s \in S^F} \sum^{t \in T} P_{N^h,t} \times X_{s,t} + \sum^{l \in L^f} \beta_l \check{\delta}_l - \gamma_l \widehat{\delta}_l$ s.t. River Chain and Block Dispatch Constraints

Yields new $X^*_{s,t}$ and $\omega^*_{\hat{h},\check{h},t} \forall s \in S^F, \forall \hat{h}, \check{h} \in H^F, \forall t \in T$

Set Offer Stack for current period.

if $r = 1$

$$Q_{r,s,\bar{t}} = X^*_{s,\bar{t}} \qquad \forall s \in S^F$$

else

$$Q_{r,s,\bar{t}} = X^*_{s,\bar{t}} - \sum_{\hat{r}=1}^{r-1} Q_{\hat{r},h,\bar{t}} \qquad \forall s \in S^F$$

end if

Tranche 3 corresponds to the price from the previous period. This block sets the single offer quantity and price for all subsequent periods and sets the amount to be fixed due to block dispatch

if $r = 3$

For all future periods, reset offers on all tranches at all hydro stations to zero

$$Q_{\hat{r},s,t} = 0 \qquad \forall \hat{r} \in R \forall t > \bar{t} \in T, \ \forall s \in S^F$$

$\widehat{P}_{\hat{r},s,t} = 0 \qquad \forall \hat{r} \in R \forall t > \bar{t} \in T, \forall s \in S^F$

Set tranche 1 offer quantity for all future periods.

$Q_{'1',s,t} = X^*_{s,t} \qquad \forall t > \bar{t} \in T, \ \forall s \in S^F$

$\widehat{P}_{'1',s,t} = 0 \qquad \forall t > \bar{t} \in T, \forall s \in S^F$

Set tranche 2 offer quantity to be max generation at maximum system fuel cost for all future periods

$Q_{'1',s,t} = U_{s,t} \qquad \forall t > \bar{t} \in T, \ \forall s \in S^F$

$\widehat{P}_{'1',s,t} = c^{MAX} \qquad \forall t > \bar{t} \in T, \forall s \in S^F$

if $\bar{t} > 1$

For each river chain belonging to agent f, if the river chain is block dispatched, set the quantity to be fixed for each $c \in C^F$

if $c \in A$ then

$X^{fix}_{s,\bar{t}-1} = X^*_{s,\bar{t}-1} \qquad \forall s \in S^C$

$\omega^{fix}_{\hat{h},\check{h},\bar{t}-1} = \omega^*_{\hat{h},\check{h},\bar{t}-1} \qquad \forall \check{h}, \hat{h} \in H^C$

elseif $c \in B$

$\omega^{fix}_{\hat{h},\check{h},\bar{t}-1} = \omega^*_{\hat{h},\check{h},\bar{t}-1} \qquad \forall \check{h}, \hat{h} \in H^C$

end if

next c

end if

end if

next c

next r

Nodal Demand for Period $\bar{t}$, $D_{n,\bar{t}}$ becomes known for all $n \in N$. Projected demands, $\overline{D}_{n,t}$ are reestimated by shifting $\overline{D}_{n,t}$ by $D_{n,\bar{t}} -, \overline{D}_{n,\bar{t}}$ for each $t > \bar{t}$ and $n \in N$

Solve vSPDR(vSPD with dynamic ramp constraints) Yields new $X^{B*}_{r,s,t} \forall s \in S, \forall r \in R, \forall t \in T$

Calculate New forecast Prices, $P_{n,t}$, the dual variables for the "Meet Nodal Demand" constraint, in $\$/MWh$.

Loop over river chains with block dispatch

for each $a \in A$

Fix the sum of dispatch for river chain a for period $\bar{t}$:

and the individual dispatches from previous period: Fix $X_{s,\bar{t}-1} = X^{fix}_{s,\bar{t}-1}$ $\forall s \in S^A$

Fix $X^{\Sigma}_{a,\bar{t}} = \sum^{s \in S^a} X^{*}_{s,\bar{t}}$

next a

Fix the spill from previous period: Fix $\omega_{\hat{h},\check{h},\bar{t}-1} = \omega^{fix}_{\hat{h},\check{h},\bar{t}-1}$ $\forall \check{h}, \hat{h} \in H$

Loop over river chains without block dispatch

for each $b \in B$

Fix the sum of dispatch for river chain b for period $\bar{t}$:

Fix $X_{s,\bar{t}} = X^{*}_{s,\bar{t}}$ $\forall s \in S^B$

next b

Fix Thermal Dispatch for period $\bar{t}$

Fix $X_{s,\bar{t}} = X^*_{s,\bar{t}}$ $\forall s \in S^T$

next $\bar{t}$

A.4 Rolling Central Pseudocode

A.4.1 Sets and Mappings used in Pseudocode

- T the set of time periods
- H the set of Hydro Stations,Reservoirs and Junctions
- L the subset of H for Reservoirs only
- L^F the subset of H for Reservoirs only corresponding to agent $f \in F$
- S the set of all stations
- S^T the set of Thermal Stations
- S^H the set of Hydro Stations.
- S^0 subset of S containing non-offering stations
- N the set of transmission nodes
- R the five tranches for hydro offers
- C the set of River Chains
- C^F the set of River Chains corresponding to agent $f \in F$

A.4.2 Variables used in Pseudocode

- $X^B_{r,s,t}$ is the generation of station $s \in S$ at trading period $t \in T$ for Tranche $r \in R$
- $\widehat{\delta}_l$ is the surplus above the target reservoir level for each reservoir $l \in L$
- $\check{\delta}_l$ is the deficit below the target reservoir level for each reservoir $l \in L$

A.4.3 Parameters used in Pseudocode

- $Q_{r,s,t}$ is the quantity offered at station $s \in S$ at trading period $t \in T$ corresponding to tranche $r \in R$
- $\widehat{P}_{r,s,t}$ is the price offered at station $s \in S$ at trading period $t \in T$ corresponding to tranche $r \in R$
- $D_{n,t}$ is the actual demand at node n$\in N$ at trading period $t \in T$
- $U_{s,t}$ is the maximum generation at station s $\in S$ at trading period $t \in T$, subject to generator derating
- $X^*_{s,t}$ is the optimal generation of station $s \in S$ at trading period $t \in T$
- α is the percentage of base fuel cost by which each tranches fuel cost exceeds the previous tranche
- $\widehat{c}_s$ is the base marginal fuel consumption cost for station $s \in S^T$. This is equal to the heat rate multiplied by the wholesale fuel cost.
- $\check{c}_s$ is the marginal operations and maintenance cost for station $s \in S^T$.
- $X^{B*}_{r,s,t}$ is the optimal generation of station $s \in S$ at trading period $t \in T$ for Tranche $r \in R$

- $X^H_{s,t}$ historical generation for station $s \in S^0$ and $t \in T$
- γ_l is the cost coefficient corresponding to having a shortage of water relative to target reservoir levels for each reservoir $l \in L$
- β_l is the cost coefficient corresponding to exceeding target reservoir levels for each reservoir $l \in L$

  γ^{lim} is some upper bound on the starting value for γ β^{lim} is some lower bound on the starting value for β
- $\widehat{\delta}_l^{min}$ is the minimum possible surplus above target reservoir level for each reservoir $l \in L$
- $\breve{\delta}_l^{min}$ is the minimum possible deficit below target reservoir level for each reservoir $l \in L$
- δ is the aggregated absolute total deviation from target levels across all reservoirs
- δ^{min} is the aggregated absolute total deviation from target levels that minimizes the penalty cost of deviation from target levels
- θ is the linear factor for scaling γ_l and $beta_l$ after each solve
- ψ is a quadratic factor for scaling γ_l and $beta_l$ after each solve
- c^{MAX} is the maximum fuel cost out of all stations in the system

A.4.4 Pseudocode

Set the offers for the thermal generators

$$Q_{r,s,t} = U_{s,t} \qquad r = 1 \forall t \in T, \forall s \in S^T$$

$$\widehat{P}_{r,s,t} = \widehat{c}_s + \breve{c}_s \qquad r = 1, \forall t \in T, \forall s \in S^T$$

$$Q_{r,s,t} = 0 \qquad r > 1, \forall t \in T, \forall s \in S^T$$

Set quantity and price to be zero for all nonoffering generators

$Q_{r,s,t} = 0$ $\qquad \forall r \in R \forall t \in T, \forall s \in S^0$

$\widehat{P}_{r,h,t} = 0$ $\qquad \forall r \in R, \forall t \in T, \forall s \in S^0$

Offer in historical generation for non-offering generators

$Qr, s, t = X^H s, t \forall s \in S^0, \forall t \in T, r = 1$

Loop over time periods, $\bar{t}$. $\bar{t}$ is always the current time period.

for $\bar{t} = 1$ to $|T|$

Set quantity and price for all hydro tranches to zero for all trading periods greater than and including $\bar{t}$

$Q_{r,h,t} = 0$ $\qquad \forall r \in R \forall t \geq \bar{t} \in T, \forall h \in S^H$

$\widehat{P}_{r,h,t} = 0$ $\qquad \forall r \in R, \forall t \geq \bar{t} \in T, \forall h \in S^H$

Set offer quantity for tranche 1 to be the maximum generation for each station for all trading periods greater than and including $\bar{t}$

$Q_{r,s,t} = U_{s,t}$ $\qquad \forall s \in S^H, \forall t \geq \bar{t} \in T, r = 1$

solve vSPD Central minimizing sum of fuel costs, penalty costs, and water penalty costs.

Yields new $X^{B*}_{s,t}$ and $\omega^*_{\hat{h},\check{h},t}$ $\qquad \forall s \in S, \forall t \in T, \forall \check{h}, \hat{h} \in H, \forall t \in T$

Offer optimal quantity from vSPD Central to vSPDR in order to get prices that are not affected by intertemporal storage

$Q_{r,s,t} = X^{B*}_{r,s,t}$ $\qquad \forall s \in S^H, \forall t \geq \bar{t} \in t$

solve vSPDR minimizing sum of fuel costs and penalty costs.

Yields new $X^{B*}_{r,s,t}$ and $P_{n,t}$ $\qquad \forall r \in R, \forall s \in S, \forall t \in T$

Fix the spill and generation for current period

fix $X_{r,s,\bar{t}} = X^{B*}_{r,s,\bar{t}}$ $\quad \forall r \in R, \forall s \in S$

fix $\omega_{\hat{h},\check{h},t} = \omega^{*}_{\hat{h},\check{h},t}$ $\quad \forall \hat{h}, \check{h} \in H \forall t \in T$

next t

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