EMBER 2.0 Hydro vSPD

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Contents

1 Introduction

The EMBER 2.0 project (Electricity Market Benchmarking Exploring Risk) uses DOASA and Hydro vSPD as counterfactuals of the electricity market in New Zealand to benchmark the differences in thermal costs, reservoir storage, generation, prices and market rents between social planning and the market. DOASA implements the SDDP technique to schedule hydro-thermal power generation in a planning horizon of weekly stages and generate policies that are Benders cuts for reservoirs in a river-valley hydro network of four river chains (Waikato River, Waitaki River, Clutha River and Manapouri River). Hydro vSPD simulates energy dispatching and pricing in half-hourly trading periods accounting for the value of reservoir storage using Benders cuts on a day-by-day basis. The results from Hydro vSPD are compared with the market results that consist of results generated using vSPD and historical reservoir storage.

Hydro vSPD is adapted from the vSPD model that is the duplicate of the market model, SPD. vSPD can be downloaded from the Electricity Market Information (EMI) website (EMI 2018b). Hydro vSPD adapted from vSPD of version 1.4 is used for 2005 to 2014. Note that the parameter of DispatchableDemandGDXGDate in the vSPDSolve.gms file for vSPD of version 1.4 is changed from 41773 to 41778 (This change was informed by Tuong Nguyen in the Electricity Authority). Hydro vSPD adapted from vSPD of version 2.0.5 is used from 2015. A national market for interruptible load reserve from October 20, 2016 is implemented in vSPD of version 3.0.3 but is ignored in Hydro vSPD. The data is from public sources, e.g., the EMI, the Ministry of Business, Innovation and Employment (MBIE), and the data in the EMBER 1.0 project.

The description of the model and data, the mathematic formulation of the model, a guide of running the model and the generation of results from output are presented.

2 Planning horizon

The planning horizon is one day that consists of half-hourly trading periods in the day. There are 46 and 50 trading periods in the days when daylight savings start and end respectively and 48 trading periods in the other days.

3 Generators in hydro power stations in four river chains

The generators in the hydro power stations in the four river chains submit offers to the market. The generators are run at short run marginal costs that are assumed to be zero, and thus the offer prices are set to zero. The offer quantities are those in vSPD. The generation is bounded by ramping limits that are the maximum increase and decrease from the generation in the previous trading period.

Power station	1/01/2005	14/04/2011	10/05/2011	11/05/2011
Aratiatia	0.284		0.2844	0.284
Ohakuri	0.2779	0.2783	0.2779	0.2783
Atiamuri	0.1958	0.1955	0.1958	0.1955
Whakamaru	0.3154	0.3164		0.3168
Maraetai	0.4979		0.4975	0.5152
Waipapa	0.1386			
Arapuni	0.4630		0.4741	
Karapiro	0.2653			

Table 1: Conversion factors (MW/cumec) and effective dates for hydro power stations in Waikato River before 13/05/2011

Power station	13/05/2011	23/05/2011	12/08/2013	8/04/2014
Aratiatia	0.2844	0.284		
Ohakuri	0.2779	0.2783	0.2779	0.284
Atiamuri	0.1958	0.1955	0.1958	
Whakamaru	0.3164			
Maraetai	0.5263	0.5267	0.5263	
Waipapa				
Arapuni		0.4622		
Karapiro			0.2639	

Table 2: Conversion factors (MW/cumec) and effective dates for hydro power stations in Waikato River from 13/05/2011

Manapouri is operated under operational constraints that are difficult to model, e.g., different minimum flows at different time and 24-hour flows in different months for different purposes (see EMI 2017c). Thus the generation of generators in the Manapouri power station are fixed as the generation in vSPD.

The conversion factor of a hydro power station is used for the generators in the power station. The conversion factors and effective dates for the power stations in the Waikato River are presented in Table 1 and Table 2, and those in the other three river chains are presented in Table 3.

1. The conversion factors of power stations in the Waikato River, Waitaki River except Tekapo A, Tekapo B, Ohau B and Ohau C, and Manapouri River are calculated from the specific energy in EMI 2017e.

2. The conversion factors of Tekapo A, Tekapo B, Ohau B, Ohau C and the power stations in the Clutha River are not available in EMI 2017e and thus they are calculated from the plant factors in EMI 2017c.

The conversion factors change on the effective dates. The conversion factors are assumed to be independent of the storage of reservoirs and head ponds.

Power station	1/01/2005	10/04/2008	1/09/2010	1/06/2011
Tekapo A	0.2322			0.2322
Tekapo B	1.2821			1.2847
Ohau A	0.5004			0.5004
Ohau B	0.4167			0.4167
Ohau C	0.4167			0.4167
Benmore	0.8176			0.8176
Aviemore	0.31			0.31
Waitaki	0.1624			0.1624
Clyde	0.5181		0.5181	
Roxburgh	0.3968		0.4016	
Manapouri	1.4641	1.5314		

Table 3: Conversion factors (MW/cumec) and effective dates for hydro power stations in Waitaki River, Clutha River and Manapouri River

4 Generators in main thermal power stations

The generators in the main thermal power stations submit offers to the market. The generators are run on short run marginal costs and thus the offer prices are set to the short run marginal costs. The offer quantities are those in vSPD. The generation is bounded by ramping limits.

The short run marginal cost (SRMC, $/MWh) is the total of the fuel cost multiplied by heat rate, the carbon cost multiplied by the heat rate, and the operating and maintenance cost.

The heat rates and fuel type of thermal power stations are presented in Table 4. The heat rates are obtained from EMI 2017a except the Stratford peakers. The heat rate for the Stratford peakers is the heat rate in the EMBER 1.0 project.

The fuel used in a thermal power station is coal, natural gas or diesel. Coal is supplied from stockpiles that are restocked under long-term contracts. Thus it is assumed that the cost is constant at 4. Natural gas is supplied by take-or-pay contracts. It is assumed that in social planning the supply can be secured and the costs are wholesale prices. The quarterly average prices of natural gas for wholesale are available in MBIE 2018. The quarterly average prices of diesel for commercial in MBIE 2018 are used as the costs of diesel. The quarterly average prices are converted into real dollars in December 2015 and the converted prices are presented in Table 5. The weekly costs in the four 13 weeks in each year are the prices of the four quarters in the year respectively. Note that the fuel costs in the input of DOASA refer to the total of fuel costs and carbon costs.

High gas and coal costs are also used and the results are compared with the results with the fuel costs above. High gas costs of Contact and Genesis and high coal costs of Genesis in nominal dollars in 2009-2018 financial years are provided by Gluyas 2018. The high gas and coal costs in 2008-2017 calendar years in real dollars in December 2015 are calculated and presented in Table 6.

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Power station	Heat rate	Fuel
Huntly main 1	10.3	coal
Huntly main 2	10.3	coal
Huntly main 3	10.3	coal
Huntly main 4	10.3	coal
Huntly e3p	7.2	natural gas
Huntly peaker	9.8	natural gas
New Plymouth 1	11	natural gas
New Plymouth 2	11	natural gas
New Plymouth 3	11	natural gas
Otahuhu B	7.45	natural gas
Stratford peakers	9.5	natural gas
Taranaki Combined Cycle	7.6	natural gas
Whirinaki	11	diesel

Table 4: Heat rates (GJ/MWh) and fuel types of thermal power stations

	Natural gas				Deisel			
Year	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
2005	4.80	4.45	4.19	5.42	24.61	26.57	28.55	27.74
2006	5.39	5.32	5.41	5.96	28.87	34.18	32.48	27.26
2007	6.21	6.28	6.30	5.87	26.00	27.42	27.88	31.06
2008	5.57	5.39	5.69	6.03	33.11	40.20	40.40	30.32
2009	7.23	7.58	7.52	7.43	26.56	24.32	25.50	25.44
2010	7.67	6.73	7.76	7.88	26.52	28.77	26.86	27.26
2011	7.39	7.23	7.31	6.23	30.13	34.09	29.40	31.06
2012	6.52	6.68	6.70	6.20	31.27	30.65	31.33	30.88
2013	6.82	6.43	6.34	6.39	30.73	28.45	30.11	29.28
2014	6.01	5.80	6.45	6.14	28.29	27.79	27.51	25.29
2015	5.55	5.72	4.88	5.04	21.73	22.50	21.84	19.88
2016	5.29	5.32	5.22	4.57	15.75	14.68	17.15	18.07
2017	5.71	4.62	5.42	5.51	19.58	20.14	19.95	23.78

Table 5: Quarterly average prices of natural gas and diesel ($/GJ) in real dollars in December 2015

	Natural gas for Contact				Natural gas for Genesis				Coal
Year	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Annual
2008	6.68	6.46	6.82	7.23	18.63	18.01	19.02	20.17	4.74
2009	9.05	9.49	9.41	9.30	16.44	17.24	17.10	16.90	4.84
2010	9.85	8.64	9.95	10.11	9.98	8.76	10.08	10.24	4.91
2011	9.17	8.97	9.06	7.73	10.06	9.84	9.94	8.48	4.74
2012	8.27	8.48	8.49	7.87	9.47	9.71	9.72	9.01	4.78
2013	8.97	8.46	8.33	8.40	10.28	9.69	9.55	9.63	4.82
2014	8.07	7.79	8.66	8.25	8.86	8.56	9.51	9.06	4.98
2015	7.84	8.08	6.90	7.13	7.82	8.06	6.89	7.11	5.41
2016	7.08	7.13	7.00	6.12	7.44	7.48	7.35	6.43	5.94
2017	6.70	5.42	6.36	6.47	7.90	6.40	7.50	7.63	6.02

Table 6: High costs of natural gas and coal ($/GJ) in real dollars in December 2015

1. The high gas and coal costs are converted into real dollars in December 2015.

2. In each calendar year, historical generation weighted average costs by companies over the financial years part of which fall into the calendar year are calculated.

3. For coal, the average costs are used as the high costs.

4. For gas, in each calendar year, scaling factors are calculated by dividing the average costs by the average MBIE quarterly gas prices in the corresponding financial years, and then the MBIE quarterly gas prices in the calendar year are inflated by the scaling factors.

The carbon cost is the cost of CO2 emission for each unit of fuel used by a thermal power station under the NZ Emission Trading Scheme. The electricity generation industry took part in the scheme on July 1, 2010, and weekly carbon costs are calculated from week 27 in 2010. The weekly carbon costs are calculated by multiplying the weekly NZU price of emission ($/tCO2e), the emission quantity from fuel (tCO2e/PJ) and a scaling factor of 1/1,000,000. NZU spot prices are available on Theecanmole 2018. The weekly NZU price in a week is the first spot price in the week, or the latest spot price before the week if no spot price is available in the week. Since two emission units are counted as one in the scheme before January 2013, the weekly NZU prices before week 1 of 2013 are divided by two. The weekly NZU prices are converted into real dollars in December 2015. The emission quantities from fuel are available on EA 2011 and they are presented in Table 7.

The operating and maintenance costs (O&M cost) of thermal power stations are presented in Table 8. The costs are those used by the Generation Expansion Model used by the Electricity Commission (EC) that are available in PB 2009

Coal	Natural gas	Diesel
91,200	52,800	0

Table 7: Emission quantities from fuel (tCO2e/PJ)

Power station	Cost
Huntly main 1	9.6
Huntly main 2	9.6
Huntly main 3	9.6
Huntly main 4	9.6
Huntly e3p	4.25
Huntly peaker	6.4
New Plymouth 1	9.6
New Plymouth 2	9.6
New Plymouth 3	9.6
Otahuhu B	4.3
Stratford peakers	6.4
Taranaki Combined Cycle	4.3
Whirinaki	10

Table 8: Operating and maintenance costs ($/MWh) of thermal power stations

except for New Plymouth 1-3 and Stratford peaks. The costs for New Plymouth 1-3 and Stratford peaks are those used in the EMBER 1.0 project. The costs are used as the costs in real dollar in December 2015 as it is suggested in PB 2009 that the costs do not change with inflation.

5 Generators with fixed generation

The generation of generators other than the generators in the hydro power stations in the four river chains and the main thermal power stations are fixed as the generation in vSPD. The offer prices are set to zero.

6 River-valley hydro network

The river-valley hydro network consists of reservoirs, head ponds, hydro power stations, canals, spillways and inflows in the Waikato River, Waitaki River, Clutha River and Manapouri River. The reservoirs are Taupo in Waikato River, Tekapo, Pukaki and Ohau in Waitaki River, Hawea in Clutha River and Manapouri (Lake Manapouri and Lake Te Anau) in Manapouri River. The head ponds provide small storage capacities. Time delays in flows are ignored.

Reservoir	Capacity	Effective time	Storage type
Taupo	855,400,000	all time	active
Tekapo	705,100,000	Jan-Feb, Oct-Dec	active and available contingent
	734,400,000	Mar	
	763,900,000	Apr, Aug	
	793,600,000	May	
	823,400,000	Jun-Jul	
	705,100,000	Sept	
Pukaki	2,335,920,000	Jan-Apr and Sept-Dec before 11/09/2012	active
	2,425,450,000	May-Aug before 11/09/2012	
	2,425,450,000	from 11/09/2012	
Ohau	48,070,000	all time	active and consented contingent
Hawea	1,405,820,000	all time	active and available contingent
Manapouri	1,029,230,000	all time	active

Table 9: Reservoir storage capacities (m3), effective time and storage type

7 Reservoirs

The storage capacities of reservoirs are obtained from the storage data in consents in EMI 2017c. The storage capacities, effective time and type of storage are presented in Table 9. The changes of storage capacities are accounted for. On the other hand, the low storage in some reservoirs are used under certain conditions in reality. The available contingent storage in Tekapo and Hawea, 191,000,000 in Jan-Mar and Oct-Dec and 263,870,000 from 25/05/2007 respectively, can be used when there is national shortage; the consented contingent storage in Ohau is used when there is forecast of large inflows; and the storage of Pukaki under 24,190,000 is used with no generation from the generator in Tekapo A. However, these conditions are ignored.

The value of reservoir storage at the end of each day is the value of national storage and is calculated using Benders cuts generated for the week by DOASA. The Benders cuts are linear functions of reservoir storage and each Benders cuts consists of an intercept and a coefficient for each reservoir.

Although Manapouri generation is fixed as the generation in vSPD, the Manapouri storage at the end of each day is different from the historical storage as the conversion factor is different. Furthermore, the historical storage can be higher than the storage capacity and Benders cuts do not provide good values for such high storage. Thus the Manapouri storage is set to the historical storage after the optimisation problem is solved. The historical daily reservoir storage are available on EMI 2017d.

Head pond	Storage capacity
Aratiatia	900,000
Ohakuri	27,400,000
Atiamuri	8,300,000
Whakamaru	17,500,000
Maraetai	17,200,000
Waipapa	6,000,000
Arapuni	31,400,000
Karapiro	19,100,000
Lake Scott	79,920
Tekapo B	10,751,132
Ruataniwha	1,440,000
Ohau C	43,215,676
Benmore	42,345,108
Aviemore	16,660,000
Waitaki	11,890,000
Dunstan/Clyde	25,200,000
Roxburgh	10,324,800

Table 10: Head pond storage capacities (m3)

8 Head ponds

The storage capacities of head ponds are presented in Table 10.

1. The storage capacities of head ponds in the Waikato River and of Ruataniwha, Aviemore and Waitaki are the active storage in consents in EMI 2017c.

2. The storage capacity of Benmore is 10% of the active storage in EMI 2017c as Benmore is operated at and above 90% of storage capacity generally.

3. The storage capacities of the other head ponds are not found in public sources and thus they are set to those used in the EMBER 1.0 Project.

The storage of head ponds at the beginning and the end of each day are assumed to be fixed at 50% of storage capacities. This prevents empty head ponds at the end of each day. The 50% is chosen so that there is storage space for the inflows and the flows released from upstream from mid-night to just before morning peak hours when demand is low.

9 Inflows

Inflows in each trading period in each day are set to the daily inflows as the former are not available in public sources. This ignores the variation of inflows

Flow	Bound	In consent	Effective date
Taupo	lower	50	12/04/2006
Aratiatia	lower	50	12/04/2006
Karapiro	lower	148 in Jan-Mar 140 or 148 in Apr and Dec 140 in May-Nov	12/04/2006
Ohau to Ruataniwha	lower	8 in May-Oct 12 in the other months	31/05/2011
Waitaki	lower	120	31/05/2011
Hawea	lower	10	25/05/2007
Clyde to Roxburgh	lower	120 at 6:26am-19:49pm	25/05/2007
Roxburgh	lower	250	25/05/2007
Hawea	upper	200 in Feb-Aug 60 in the other months	25/05/2007

Table 11: Lower bounds and upper bounds (cumec) of flows and effective dates

during the day. The daily inflows are the inflow data available on EMI 2017b. Note that the inflows at Karapiro are calculated from those at Arapuni and a tributary factor as a large number of inflows at Karapiro in actual data are smaller than those at Aarapuni, implying possible errors in the actual data.

10 Flows

There are lower bounds and upper bounds on the flows in the hydro network. The lower bounds and upper bounds and effective dates in consents in EMI 2017c are presented in Table 11. The lower bound of flow from Karapiro in April and December depends on the operation of Huntly power stations but it is set to 148 to cover the smaller lower bound. The effective dates are accounted for. The lower bounds and upper bounds that are not available in EMI 2017c are the data used in the EMBER 1.0 Project.

Penalty variables are used to allow violations of lower bounds and upper bounds. The effect of penalty costs on node prices should be as small as possible.

1. If the penalty cost is higher than the cost to meet demand, then the node price is the latter and thus not affected by the penalty cost.

2. If the penalty cost is lower than the cost to meet demand, then the flow bound constraint may be violated, and the node price will be the penalty cost and thus underestimated.

3. If the flow bound is violated due to infeasibility, e.g., not enough water in upstream reservoirs and head ponds to meet flow lower bound, then the violation is not related to demand and thus penalty cost has no impact on node price.

Thus the penalty costs are set to high values, which are \$1,000/MWh. The costs from penalty variables are calculated by multiplying the penalty variables by the penalty cost, the length of a trading period, and a high conversion factor (7 MW/cumec) that converts the penalty variables into energy.

11 HVDC risk and reserves

Hydro vSPD is run with HVDC risk and reserves, which is the most important risk. The offer quantities of partially loaded, tail water depressing and interruptible load reserves are set to the historical levels and the offer prices are set to zero. The HVDC pole ramp up is set to the historical level. The other reserves strongly depend on the offers to meet demand and thus they will be different from historical levels but these haven't been derived for Hydro vSPD. However, it is assumed that if vSPD is run with HVDC risk and reserves, then net free reserve will be available to meet reserve requirements. The minimum net free reserve required in such a vSPD run is used in Hydro vSPD.

12 Solving methods

Multiple threads are used in the GAMS model option and the concurrent method is used in the Cplex option to allow the use of multiple methods in parallel to speed up the solving of optimisation problems. However, the concurrent method may fail to solve an optimisation problem, e.g., the Barrier method may return a solution with unscaled infeasibility that is likely related to the scaling of the optimisation problem. Thus if this occurs, then the dual simplex method is used to re-solve the problem, and if the dual simplex method fails, then the primal simplex method is used.

13 Mathematical formulation

The constraints copied from vSPD are defined abstractly by the following constraint.

$$d_t \in D_t, q_t \in Q_t, r_t \in R_t, w_t \in W_t, y_t \in Y_t, z_t \in Z_t, t \in T$$

where D_t is the set of demand, Q_t is the set of dispatches, R_t is the set of reserves, W_t is the set of bids for interruptable load reserves, Y_t is the set of flows in transmission and distribution network, Z_t is the set of bids for energy, and T is the set of trading periods in the day.

The water mass balancing for reservoirs and head ponds and for the other nodes in the hydro network are defined in the following constraints.

$$x_{it} = x_{i,t-1} - \tau u_{it} + \tau v_{it}, i \in J \cup K, J \subset I, K \subset I, t \in T$$

$$u_{it} = v_{it}, i \in I, i \notin J \cup K, t \in T$$

where x_{it} is the storage of reservoir and head pond i, τ is the number of seconds in one trading period, u_{it} is the flow sent from node i, v_{it} is the flow received at node i, J is the set of reservoirs, K is the set of head ponds, and J and K are subsets of I that is the set of nodes in the river-valley hydro network.

The flows sent and received are calculated in the following constraints.

$$u_{it} = h_{it} + \sum_{i' \in S_i} s_{ii't}, i \in I, t \in T$$

$$v_{it} = \sum_{i' \in H_i} h_{i't} + \sum_{i' \in S'_i} s_{i'it} + \omega_{it}, i \in I, t \in T$$

where h_{it} is the generating flow, $s_{ii't}$ is the spill sent from node i to node i', S_i is the set of nodes at which spills sent from node i are received, $h_{i't}$ is the generating flow at node i', H_i is the set of nodes from which generating flows are sent to node i, $s_{i'it}$ is the spill sent from node i' to i, S'_i is the set of nodes from which spills are sent to node i, and ω_{it} is the inflow.

The boundary conditions for the storage of reservoirs and head ponds are defined in following constraints.

$$x_{i,0} = \bar{x}_i, i \in J \cup K$$

$$x_{i,48} = x_{i,0}, i \in K$$

$$x_{i,48} = \frac{1}{2}\hat{x}_i, i \in K$$

$$0 \leq x_{it} \leq \hat{x}_i, i \in J \cup K, t \in T$$

where $\bar{x}_i$ is the storage at the beginning of the day, and $\hat{x}_i$ is the storage capacity.

The lower bounds and upper bounds on flows in the river-valley hydro network are presented in the following constraints.

$$s_{ii't} + s^-_{ii't} \geq \check{s}_{ii't}, i \in I, i' \in I, t \in T$$

$$s_{ii't} - s^+_{ii't} \leq \hat{s}_{ii't}, i \in I, i' \in I, t \in T$$

$$u_{it} + u^-_{it} \geq \check{u}_{it}, i \in I, t \in T$$

$$u_{it} - u^+_{it} \leq \hat{u}_{it}, i \in I, t \in T$$

$$h_t, u^-_t, u^+_t, s^-_t, s^+_t \geq 0, t \in T$$

where $s_{ii't}^-$ and $s_{ii't}^+$ are the penalty variables for the violation of $\check{s}_{ii't}$ and $\hat{s}_{ii't}$ that are the lower bound and upper bound of spill sent from node i to node i', and u_{it}^- and u_{it}^+ are the penalty variables for the violation of $\check{u}_{it}$ and $\hat{u}_{it}$ that are the lower bound and upper bound of flow sent from node i.

The power generated from flows in hydro power stations are calculated in the following constraint.

$$g_{it} = \gamma_i h_{it}, i \in M, M \subset I, t \in T$$

where g_{it} is the generation in hydro power station i, γ_i is the conversion factor, and M is the set of hydro power stations and is a subset of I.

The mappings of hydro power stations and generators in the stations are presented in the following constraint.

$$g_{it} = \sum_{o \in O_{it}} q_{ot}, i \in M, t \in T$$

where q_{ot} is the dispatch of generator o, and O_{it} is the set of generators in hydro power station i which submit energy offers to the market.

The following constraints are related to the dispatches of generators.

$$q_{o,t-1} - \check{q}_{ot} \leq q_{ot} \leq q_{o,t-1} + \hat{q}_{ot}, o \in O_t, O_t \subset P_t, t \in T$$

$$q_{o,0} = \bar{q}_o, o \in O_t, t \in T$$

$$q_{ot} = \bar{q}_{ot}, o \in P_t, o \notin O_t, t \in T$$

where $\check{q}_{ot}$ and $\hat{q}_{ot}$ are the maximum ramp-down and ramp-up for generator o, $\bar{q}_o$ is the dispatch just before the beginning of the day, $\bar{q}_{ot}$ is the dispatch in vSPD, and O_t is the set of generators that submit energy offers to the market, and P_t is the set of all generators.

The HVDC risk and reserves are presented in the following constraint.

$$r_{lcet} = y_{lt} - f_{lcet} - v_{lct}, l \in L, c \in C, e \in E, e = \text{DCCE}, t \in T$$

$$r_{lcet} = y_{lt} - f_{lcet}, l \in L, c \in C, e \in E, e = \text{DCECE}, t \in T$$

where r_{lcet} is the risk at island l for reserve type c and HVDC risk e (DCCE and DCECE), y_{lt} is the HVDC flow received at island l, f_{lcet} is the net free reserve at island l for reserve type c and HVDC risk e, v_{lct} is the net free reserve at island l for reserve type c, L is the set of islands, C is the set of reserve types, and E is the set of HVDC risk classes.

The objective function and the value of reservoir storage are presented in the following constraints

$$\max \sum_{t \in T} \left[\phi_t(z_t) - \sum_{o \in O_t} \pi_o q_{ot} - \varphi_t(w_t) - \psi_t(q_t, r_t, w_t, y_t, z_t) - \rho\left(s_t^+, s_t^-, u_t^+, u_t^-\right) \right] + \theta$$

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Parameter	Value
Model	Standard vSPD
License model	1 (Developer)
Solver name	CPLEX
Vectorisation	1 (Yes)
Produce trade period reports	1 (Yes)
Use variable reserves	-1 (Auto)
Include reserves	1 (Yes)
Include AC losses	1 (Yes)
Include HVDC losses	1 (Yes)
Use Transpower loss segments	1 (Yes)
Resolve circular branch flows	0 (No)
Model AC branch limits	1 (Yes)
Model HVDC branch limits	1 (Yes)
LP time limit	36000 seconds
MIP time limit	36000 seconds
Operating mode	0 (Public)

Table 12: Settings for Hydro vSPD with HVDC risk and reserves

$$\theta \leq \alpha_n + \sum\nolimits_{i \in J} \beta_{in} x_{i,48}, n \in N$$

where ϕ_t is the value function for z_t, π_o is the short run marginal cost of generator o, φ_t is the cost function for w_t, ψ_t is the cost function for penalty variables in vSPD, ρ is the cost function for the penalty variables in the constraints for the river-valley hydro network, θ is the value of reservoir storage, α_n is the intercept in the Benders cut n, β_{in} is the coefficient for reservoir i in the Benders cut n, and N is the set of indecies of Benders cuts.

14   Guide to run Hydro vSPD

Hydro vSPD is run by running a macro in a spreadsheet or the runvSPD.gms file in GAMS in the Program_Mod folder. The macro generates the vSPDsettings.inc file that contains the settings selected in the spreadsheet, and vSPDsettings.inc is used by runvSPD.gms. The settings of Hydro vSPD with HVDC risk and reserves are presented in Table 12. If the Include reserves parameter is set to 0, which sets the useReserveModel parameter in vSPDsettings.inc to 0, then Hydro vSPD is run with no reserve. Note that it is recommended that the suppressOverrides parameter in vSPDsettings.inc is set to 1 manually to ignore the code of overriding demand and price.

One of the main input are gdx data files that are used in vSPD. These files are available on EMI 2018a. There is one gdx data file for each day from 2005 to 2017 except 11 days.

- On August 5, 6 and 10, 2009, and December 19, 2016, there are two files that are identical except the data for case name and file name, and the first file is used.

- On July 21 and December 9, 2009, one file contains the data for the first some trading periods, the other file contains the data for the remaining trading periods of the day, and the violation costs in the parameters of i_CVPValues are different in the two files. Since the i_CVPValues in the second file does not change the solutions in vSPD run with the first file, the two files are merged with the i_CVPValues in the second file overwriting that in the first file.

- On July 21 and December 9 in 2009 and March 2, 3 and 17 in 2010, one file contains the data for the first some trading periods, the other file contains the data for the remaining trading periods of the day, and there is no conflict in data. The two files are merged.

The input can be changed in the following files.

1. In the Input folder

   (a) F.gdx for gdx data file, where F is the name of the file, e.g., FP_20050101

   (b) F_fuel_cost.csv in the fuel_cost folder for the total of fuel cost and carbon cost

   (c) F_OfferResults_TP.csv in the generation folder for the generation in vSPD

   (d) F_inflow in the inflow folder for the daily inflows

   (e) F_end_storage in the end_storage folder for the reservoir storage at the end of the day

   (f) BendersCuts_1_1.csv and BendersCuts_2_1.csv in the Cuts folder for the Benders cuts in two weeks

2. In the Programs_Mod folder

   (a) vSPDfileList.inc for the names of gdx data files

   (b) vSPDpaths.inc for runName that is the name of the folder for output

   (c) RiverData.xls for the data of river-valley hydro network

   (d) vSPD_boundary.gdx for the initial storage and initial generation of the first day

The vSPD_boundary.gdx file for the first day can be generated by running Hydro vSPD.

1. The initial storage is in the reservoirs.xlsx file in the Programs_Mod folder, and the parameter of useInitialStorage in the file is set to 1.

2. The initial generation is in the gdx data file in the Input folder.

3. Hydro vSPD is run and then terminated after vSPD_boundary.gdx has been generated.

4. The parameter of useInitialStorage in reservoirs.xlsx is changed back to 0.

Hydro vSPD generates output in csv files.

15   Generate result from Hydro vSPD output

The followings are examples of results that can be generated from Hydro vSPD output.

1. Daily generation

2. Weekly thermal costs

3. Node prices of upper North Island, lower North Island and South Island

4. Weekly revenues, costs and market rents of companies

5. Demand violation by trading periods

6. Daily reservoir storage

7. End storage values

Daily generation is available in the OfferResults.csv files. Note that on July 21, 2009, the daily generation of each generator in the file appears twice as the company of the generator is presented by its name and then by a numerical code.

Weekly thermal costs are the total of weekly thermal costs of main thermal power stations. The latter are the total of daily thermal costs that are calculated by multiplying the daily generation by the short run marginal cost.

Node prices of the upper North Island, lower North Island and South Island are the prices at the nodes of OTA2201, HAY2201 and BEN2201 respectively. The prices by trading periods are obtained from the NodeResults_TP.csv files and they can be up to half million, particularly when there are demand violations. However, in reporting the node prices are capped by \$10,000/MWh if there are demand violations as the pay-out price by the Electricity Authority (EA) for demand violation is between \$10,000/MWh and \$20,000/MWh, and capped by \$1,000/MWh otherwise as 99.8% of historical node prices in trading periods without demand violation are less than this.

The weekly revenue of a company is the total revenue over the generators owned by the company over the week, and the revenue from a generator is calculated by multiplying the generation of the generator by the price at the node to which the generator supplies energy. The companies are Contact, Genesis, Mercury, Meridian and Trustpower, and they own the hydro power stations

in the four river chains, the main thermal power stations and numerous small power stations. Generation by trading periods are obtained from the Offer-Results_TP.csv files. Node prices by trading periods are obtained from the NodeResults_TP.csv files, and again, they are capped. Note that the Tekapo A and Tekapo B power stations were transferred from Meridian to Genesis on June 1, 2011, and thus the ownerships of the revenues are changed. The weekly costs of each company are the weekly thermal costs of thermal power stations owned by the company that are calculated using the daily generation and short run marginal costs of the thermal power stations. The weekly market rents for each company are calculated as the difference of the weekly revenues and the weekly thermal costs.

The demand violations by trading periods are obtained from the SummaryResults_TP.csv files.

The daily reservoir storage are obtained from the Levels.csv files.

The end storage value at the end of a week is calculated using the storage at the end of the last day in the week and the Benders cuts for the week.

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