Interconnection-wide Hour-ahead Scheduling in the Presence of Intermittent Renewables and Demand Response: a Surplus Maximizing Approach

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Abstract

This paper describes a new approach for solving the multi-area electricity resource allocation problem when considering both intermittent renewables and demand response. The method determines the hourly inter-area export/import set that maximizes the interconnection (global) surplus satisfying transmission, generation and load constraints. The optimal inter-area transfer set effectively makes the electricity price uniform over the interconnection apart from constrained areas, which overall increases the consumer surplus more than it decreases the producer surplus. The method is computationally efficient and suitable for use in simulations that depend on optimal scheduling models. The method is demonstrated on a system that represents North America Western Interconnection for the planning year of 2024. Simulation results indicate that effective use of interties reduces the system operation cost substantially. Excluding demand response, both the unconstrained and the constrained scheduling solutions decrease the global production cost (and equivalently increase the global economic surplus) by \$12.30B and \$10.67B per year, respectively, when compared to the standalone case in which each control area relies only on its local supply resources. This cost saving is equal to 25% and 22% of the annual production cost. Including 5% demand response, the constrained solution decreases the annual production cost by \$10.70B, while increases the annual surplus by \$9.32B in comparison to the standalone case.

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Keywords

Demand response, energy market, renewable intermittency, resource allocation, western interconnection

Nomenclature

A	Market state solution matrix
b	Market condition vector
d	Demand curve slope, in $\$/(\text{MWh.MW})$
e	Net export, in MW
f	Transfer flow, in MW
p	Price, in $\$/\text{MWh}$
p_{max}	Must-serve load price, in $\$/\text{MWh}$
p_{min}	Must-take generation price, in $\$/\text{MWh}$
q	Quantity, in MW
s	Supply curve slope, in $\$/(\text{MWh.MW})$
x	Market state vector
Y	Connectivity matrix
α	Degree of demand inelasticity
Δ	Difference operator
ω	Combined demand and supply slope, in $\$/(\text{MWh.MW})$
Ω	Diagonal matrix of combined slopes

Subscripts

0	Standalone
c	Clearing
d	Demand
p	Price
q	Quantity

r	Responsive
s	Supply
u	Unresponsive
w	Must-take

1. Introduction

Most jurisdictions in North America have adopted renewable energy portfolio policies as part of efforts to reduce greenhouse gas emissions. The inherent intermittency of renewables is the main challenge to the large-scale integration of these clean resources at high penetration levels. The traditional utility approach to generation variability is to operate reserve units, which are usually more costly and may increase emissions. Demand response is a zero-emission and potentially lower-cost alternative to the use of generation reserves. It also benefits the flexible load through payment for their services, and benefits all consumers through lowered electricity costs. The US Department of Energy has adopted a definition of demand response that is now widely recognized for its inclusiveness [1]: “load variations in response to changes in both financial incentives and/or reliability signals over time”.

The idea of including demand response in electricity markets is discussed in a large body of recent works. The impact of demand response integration on peak energy consumption, energy price and emissions under load uncertainty is analyzed in [2]. A model of demand response participation in real-time markets to minimize the operation cost considering the load elasticity is formulated in [3]. The interaction between renewable intermittency and demand response in the market environment is investigated in [4].

Load fluctuations and renewable generation intermittency are generally not strongly correlated with each other over a large interconnected system that includes multiple balancing authorities [5]. As a result, the combined interconnection power fluctuations are smaller than the sum of the variations in individual balancing authorities. Neighbouring jurisdictions can take advantage of the geographical diversity of renewable resources within the system, and cooperate more effectively to mitigate the intermittency of renewable power generation. This cooperation, which is beneficial from both reliability and economic viewpoints, requires an enhanced transmission system, sometimes referred to as a “supergrid” [6]. A recent study of consolidation of balancing authorities in the US [7] showed that if planners moved away from a regionally divided electricity system to a national system using high-voltage direct-current transmission lines then the deployment of wind

34 and solar power could reduce CO₂ emissions by up to 80% relative to 1990
35 levels, without an increase in electricity price.

36 Resource scheduling using locational marginal price (LMP) has been the
37 foundation of modern electricity system operations since the early 1980s
38 when it was first introduced [8]. The basic LMP solution was subsequently
39 extended to perform security constrained economic dispatch (SCED) to sat-
40 isfy operational constraints. This family of solutions has been deployed very
41 successfully by transmission system operators [9]. However, the LMP formu-
42 lation considers load to be essentially inelastic. Approaches to compensating
43 demand response that allow consideration of price sensitive loads have been
44 examined [10]. For policy-makers seeking to study the widespread develop-
45 ment of renewable resources and the impact of demand response in system
46 operation, the preferred LMP/SCED solution to the resource scheduling
47 problem presents a significant barrier to adoption because the system models
48 are typically constructed in a manner that assumes: (i) the system operation
49 is dominated by supply resources with significant and relatively consistent
50 fixed and variable cost components throughout an interconnected system,
51 and (ii) demand is essentially inelastic and predictable. Solutions to the
52 demand response problem include those proposed by the US Federal Energy
53 Regulatory Commission [11]. Unfortunately, renewable resources such as
54 wind and solar do not fulfill assumption (i), and short-term redispatchable
55 demand does not conform well to assumption (ii).

56 A deep understanding of the interconnection-scale impact of demand re-
57 sponse integration is difficult to achieve in the absence of accurate resource
58 allocation models that properly consider the system-wide impact of demand
59 response on locational energy price calculations and generation resource al-
60 location. This is even more important for the case of large interconnected
61 systems where mixed pricing mechanisms are extant, such as in the Western
62 Electricity Coordinating Council (WECC). In the WECC some regions have
63 fully developed energy markets and others do not, and multiple balancing
64 authorities operate and interact through a myriad of bilateral contracts and
65 other financial arrangements including some as obscure as the Columbia
66 River Treaty [12]. In an effort to address these barriers and to study op-
67 timal operation of large-scale interconnections, we are motivated to find a
68 more flexible and general model of the resource scheduling problem based
69 on energy pricing. In the absence of price sensitive loads, the problem of
70 unit commitment is to determine the hourly generation schedule in a way
71 that minimizes the operational costs, which equivalently maximizes the eco-
72 nomic surplus (social welfare) [13, 14]. Therefore solving the traditional
73 LMP problem is sufficient. However, when a significant amount of price

sensitive loads is present, minimizing cost is no longer a satisfactory objective, and maximizing surplus is preferred [15], as described in Section 2. Surplus maximization for the unit commitment problem has been already formulated at the balancing authority level [16, 17, 18]. In the present work, we are interested in analyzing this problem at the interconnection level. More precisely, we seek a set of inter-area power transfers that maximizes the global surplus, which is defined as the sum of consumer and producer surpluses over all balancing authorities in an interconnection.

The optimal operation of the interconnection helps utilities produce electricity with a lower cost, integrate more intermittent renewables, and defer or cancel costly investments in grid infrastructure. Previous work [19] has shown the potential annual savings in production cost due to consolidation of balancing authorities ranges from 2.4% to 3.2%, considering transmission congestions. The full coppersheet consolidation of the WECC system provides an additional 1.4% improvement. However this study did not consider the impact of demand response on system resource allocation. Load management assists the WECC system operators in dealing with uncertainty in demand and intermittent resource output [20].

We consider one important reference to be the inelastic demand scenario in which the WECC system as a whole is operated in the most economically efficient manner. This scenario is unlikely because of various jurisdictional regulations, but it does provide an upper bound for the achievable system-wide economic benefits considering the transmission constraints. Thus, demand response with different penetration levels across the system, and potential surplus increases are evaluated with respect to this best achievable performance absent demand response. It should be noted that the outcome of this work is a model to study system-wide scenarios for planning rather than proposing an operational tool to be used in WECC.

Energy scheduling and reserve scheduling can be performed simultaneously to achieve a more economically-efficient use of both supply and demand resources, particularly when reserve sharing is anticipated to be significant [21, 22]. We exclude reserve scheduling in this formulation/simulation for simplicity. But we recognize that including it is an essential future work.

The new contributions of this work are: (i) a new resource allocation method that incorporates the market-driven demand response into the unit commitment problem; (ii) a new model of the interchange export/import scheduling problem for the global (interconnection-wide) surplus maximization objective; and (iii) a demonstration of the proposed model on the Western Interconnection for the planning year 2024. In Section 2 an overview on the double auction market theory is provided, and in Section 3 the schedul-

ing problem considering demand price responsiveness is formulated. In Section 4, a reduced model of the WECC system is presented, and in Section 5, simulation results are discussed.

2. Electricity Markets

The ultimate purpose of the proposed model of resource allocation is to determine the hourly schedule for the most economically efficient mix of supply and demand resources that does not violate the transfer constraints on system interties within an interconnection. This hourly schedule is essential to establishing the intra-hourly control reference for both supply and demand resource dispatch, which is needed to evaluate the performance of short-term demand response control strategies. To obtain this schedule, an hour-by-hour virtual double auction wholesale market is assigned to each of the system's control areas in which both supply and demand resources participate. Although the magnitude of the responsive load is relatively small, it is still worth considering its impact on the optimal schedule, particularly in the presence of substantial intermittent renewable resources. One key advantage of using the proposed model is that it facilitates modeling of inter-temporal effects such as demand response by load shifting and recovery after load curtailment.

2.1. Market clearing process

We begin by considering how prices and quantities are computed in an area. In general, both supply and demand curves are composed of a series of linear segments (sell or buy bidding quantities/prices). For simplicity, we assume supply curves only include a flat segment for non-dispatchable generators (e.g. wind and nuclear power) and a variant segment for dispatchable generators. Similarly, we assume demand curves consist of a flat segment for must-serve loads and a variant segment for deferrable loads (e.g. electric vehicles). The supply and demand curves are given as:

$$p_s = \begin{cases} s (q_s - q_w) + p_{min} & q_s > q_w \\ p_{min} & \text{otherwise,} \end{cases} \quad (1a)$$

and

$$p_d = \begin{cases} d (q_d - q_u) + p_{max} & q_d > q_u \\ p_{max} & \text{otherwise,} \end{cases} \quad (1b)$$

respectively, where p_s is the supply price, $s > 0$ is the slope of the supply curve, q_s is the supply quantity, q_w is must-take (non-dispatchable) generation, p_{min} is the must-take price, p_d is the demand price, $d < 0$ is the

Fig. 1: A double auction electricity market.

146 slope of the demand curve, q_d is the demand quantity, q_u is must-serve load,
 147 and p_{max} is the must-serve price. The slope of an inelastic demand curve is
 148 infinite ($d \rightarrow -\infty$). Supply and demand curves are illustrated in Fig. 1.

149 The supply and demand prices, p_s and p_d respectively, of energy as well
 150 as the supply and demand quantities, q_s and q_d respectively, of power must
 151 satisfy the linear system:

$$\mathbf{Ax} = \mathbf{b}, \quad (2a)$$

152 where the matrix $\mathbf{A}$ represents the area supply and demand, the vector $\mathbf{x}$
 153 represents the prices and quantities for supply and demand, and the vector
 154 $\mathbf{b}$ represents the solution condition. In the case of the simple linear supply
 155 and demand system above, we have:

$$\mathbf{A} = \begin{bmatrix} -d & 1 & 0 & 0 \\ 0 & 0 & -s & 1 \\ -1 & 0 & 1 & 0 \\ 0 & -1 & 0 & 1 \end{bmatrix}, \quad \mathbf{x} = \begin{bmatrix} q_d \\ p_d \\ q_s \\ p_s \end{bmatrix}, \quad \text{and} \quad \mathbf{b} = \begin{bmatrix} p_{max} - d q_u \\ p_{min} - s q_w \\ \Delta q \\ \Delta p \end{bmatrix}, \quad (2b)$$

156 where Δq is the export (or import if $\Delta q < 0$) quantity and Δp is the price
 157 subsidy (or tax if $\Delta p < 0$). Note that if both s and d are infinite, this
 158 formulation is not appropriate.

159 The solution price and quantity at which supply equals demand in a
 160 standalone area (both Δq and Δp are zero) is found by solving the *standalone*

161 *area problem:*

$$\mathbf{x}_0 = \mathbf{A}^{-1}\mathbf{b} = [q_0 \ p_0 \ q_0 \ p_0]^T. \quad (2c)$$

162 The supply and demand quantities for a given price p can be found by solving
163 the *quantity problem*:

$$\mathbf{x}_p = \mathbf{A}_p^{-1}\mathbf{b}_p = [q_d \ p \ q_s \ p]^T, \quad (3a)$$

164 where

$$\mathbf{A}_p = \begin{bmatrix} -d & 1 & 0 & 0 \\ 0 & 0 & -s & 1 \\ 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix}, \text{ and } \mathbf{b}_p = \begin{bmatrix} p_{max} - d \ q_u \\ p_{min} - s \ q_w \\ p \\ p \end{bmatrix}. \quad (3b)$$

165 Similarly, the supply and demand prices for a given quantity q can be
166 found by solving the *price problem*:

$$\mathbf{x}_q = \mathbf{A}_q^{-1}\mathbf{b}_q = [q \ p_d \ q \ p_s]^T, \quad (4a)$$

167 where

$$\mathbf{A}_q = \begin{bmatrix} -d & 1 & 0 & 0 \\ 0 & 0 & -s & 1 \\ 1 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 \end{bmatrix}, \text{ and } \mathbf{b}_q = \begin{bmatrix} p_{max} - d \ q_u \\ p_{min} - s \ q_w \\ q \\ q \end{bmatrix}. \quad (4b)$$

168 Another important problem required to determine the multi-area sched-
169 ule is finding the price at which the difference between supply and demand
170 quantities (export) is Δq . The clearing price, supply and demand quantities
171 can be found by solving the *export problem* (or *import problem* for $\Delta q < 0$):

172

$$\mathbf{x} = \mathbf{A}^{-1}\mathbf{b}_{\Delta q} = [q_d \ p \ q_s \ p]^T, \quad (5a)$$

173 where

$$\mathbf{b}_{\Delta q} = \begin{bmatrix} p_{max} - d \ q_u \\ p_{min} - s \ q_w \\ \Delta q \\ 0 \end{bmatrix}. \quad (5b)$$

174 In addition, if there is a difference between supply and demand prices
175 such as a renewable subsidy or a carbon tax, the clearing quantity, supply
176 and demand prices can be found by solving the *subsidy problem* (or *tax*

177 *problem for $\Delta p < 0$):*

$$\mathbf{x} = \mathbf{A}^{-1} \mathbf{b}_{\Delta p} = [q \quad p_d \quad q \quad p_s]^T, \quad (6a)$$

178 where

$$\mathbf{b}_{\Delta p} = \begin{bmatrix} p_{max} - d \quad q_u \\ p_{min} - s \quad q_w \\ 0 \\ \Delta p \end{bmatrix}. \quad (6b)$$

179 2.2. Surplus calculation

180 The double auction market finds the quantity and price that maximize
 181 the total economic surplus, which is geometrically the area between the
 182 supply and demand curves, as shown in Fig. 1. By definition, the total
 183 surplus is the summation of the producer surplus (the red hatched area)
 184 and the consumer surplus (the blue hatched area) [13]. The green hatched
 185 area is the electricity production cost.

186 The idea of global surplus maximization is presented through an exam-
 187 ple. Consider two control areas with identical demand curves and slightly
 188 different supply curves, as illustrated in Fig. 2. The must-take supply re-
 189 source is 2000 MW in Area *A*, and 1000 MW in Area *B*. If these areas are
 190 not connected, their markets will be cleared under the standalone condition
 191 as shown in Table 1.

192 When we consider the unconstrained transfer problem, the generation
 193 units in Area *A* that did not get dispatched when the tieline was not oper-
 194 ating are now dispatched to serve additional load in Area *B*. Despite Area
 195 *A*, the generation in Area *B* decreases up to the point where the price dif-
 196 ference between two areas is zero as illustrated in Fig. 3. Notice that the
 197 clearing price increases in Area *A* and decreases in Area *B*. As a result,
 198 demand quantity decreases in Area *A* and increases in Area *B* such that
 199 the difference between supply and demand quantities is 500 MW in Area
 200 *A* and -500 MW in Area *B*. Electricity exchange, like any other economic
 201 transaction, increases the global surplus (social welfare), as tabulated in Ta-
 202 ble 2. The maximum global surplus which is obtained under this condition
 203 is referred to as the *coppersheet solution*.

204 Now we constrain the tieline's transfer capacity to 400 MW, which is
 205 insufficient to equalize the prices, as illustrated in Fig. 4. Table 3 shows that
 206 the global surplus associated with the constrained transfer solution (\$2666k)
 207 is between the standalone (\$2643k) and coppersheet surpluses (\$2679k). A
 208 surplus-maximizing scheduler identifies the tieline flow such that it either

Fig. 2: Standalone markets.

Fig. 3: Interconnected markets with unconstrained transfer capacity.

Fig. 4: Interconnected markets with constrained transfer capacity.

209 zeros out the price difference or fully utilizes the transfer capacity. This
 210 scheduling problem becomes more complex when the number of areas and
 211 tielines is increased.

Table 1: Standalone schedule and surplus (zero MW exchange)

Control area	Price [\$/MWh]	Demand [MW]	Supply [MW]	Consumer sur. [k\$/h]	Producer sur. [k\$/h]	Total sur. [k\$/h]
<i>A</i>	214	3286	3286	898	566	1464
<i>B</i>	375	3143	3143	439	740	1179
Total	284	6429	6429	1337	1306	2643

Table 2: Coppersheet schedule and surplus (500 MW exchange)

Control area	Price [\$/MWh]	Demand [MW]	Supply [MW]	Consumer sur. [k\$/h]	Producer sur. [k\$/h]	Total sur. [k\$/h]
<i>A</i>	286	3214	3714	666	816	1482
<i>B</i>	286	3214	2714	666	531	1197
Total	286	6428	6428	1332	1347	2679

Table 3: Constrained transfer schedule and surplus (400 MW exchange)

Control area	Price [\$/MWh]	Demand [MW]	Supply [MW]	Consumer sur. [k\$/h]	Producer sur. [k\$/h]	Total sur. [k\$/h]
<i>A</i>	271	3629	3229	713	763	1476
<i>B</i>	300	2800	3200	620	570	1190
Total	284	6429	6429	1333	1333	2666

212 3. Inter-area Transfer Scheduling

213 In this section, we formulate the inter-area transfer scheduling problem,
 214 and determine the export/import schedule that maximizes the global surplus
 215 excluding and including transmission constraints, i.e., the coppersheet and
 216 constrained transfer solutions, respectively.

217 3.1. Surplus maximization

218 The objective function maximizes the global surplus by varying the local
 219 supply and demand dispatch quantities over the interconnection. The op-
 220 timization effectively aims to maximize the sum of the areas circumscribed
 221 by the triangles bounded by the supply and demand curves and the price

222 after export/import (see Fig. 3 and Fig. 4). Because the standalone surplus
 223 is invariant, it can be ignored in the formulation for surplus maximization.
 224 The optimization problem for an N -control area system is stated as:

$$\max_{q_{s_n}, q_{d_n}} \sum_{n=1}^N \frac{1}{2} (p_{c_n} - p_{0_n}) (q_{s_n} - q_{d_n}), \quad (7a)$$

225 subject to:

$$q_{u_n} \leq q_{d_n} \leq q_{u_n} + q_{r_n}. \quad (7b)$$

226 Note that supply and demand constraints are not needed because they are
 227 fully captured by the supply and demand curves. The objective function
 228 can be simplified to (see Appendix 1):

$$\min \frac{1}{2} \sum_{n=1}^N \omega_n e_n^2, \quad (7c)$$

229 where e_n is the difference between the supply and the demand quantities
 230 (net export), and $\omega_n = \frac{s_n d_n}{s_n - d_n}$ is the combined demand and supply slope in
 231 area n .

232 Negative prices are allowed in the optimization, but the surplus calcu-
 233 lation is modified whenever the clearing price before power exchange (p_0)
 234 or after (p_c) is negative. As illustrated in Fig. 5, the positive-price region
 235 (red area) is considered as the true surplus increase, excluding the negative-
 236 price region (yellow area). If the standalone price is negative in an area
 237 (left side market), as long as the export cannot push the clearing price
 238 beyond 0 \$/MWh, the producer surplus is zero, and the supply quantity
 239 equals the maximum demand ($q_u + q_r$) plus the export (e). Notice that
 240 the resource allocation is at the hour-ahead scheduling level not at the real-
 241 time operation level, thus a situation in which the generation exceeds the
 242 required power does not occur so that generators never pay a penalty for
 243 over-production simply because they can never be allowed to over-produce.
 244 The actual surplus appears beyond 0 \$/MWh, where the supply quantity
 245 exceeds the local must-take generation. When the clearing price is negative
 246 (right side market), the actual import will be the difference between the
 247 maximum demand ($q_u + q_r$) and the local must-take generation (q_s), which
 248 happens at 0 \$/MWh. Thus, the surplus increase beyond this price is virtual
 249 and will never be realized during operation. If both prices are negative, the
 250 surplus increase is zero—if an area has too much excess power generation
 251 such that after exporting to its neighboring jurisdictions the clearing price

Fig. 5: Surplus calculation with a negative price.

is still negative, the area's income from exporting is zero.

3.2. Coppersheet solution

Under the maximum global surplus, we expect the price to be the same over the entire interconnection, which gives the most economically efficient allocation of supply and demand resources. To obtain this *coppersheet price*, we construct the coppersheet supply curve by combining all supply curves, and the coppersheet demand curve by combining all demand curves. From Eq. (2c), the intersection point determines the coppersheet quantity $\tilde{q}$ and price $\tilde{p}$:

$$\begin{bmatrix} \tilde{q} \\ \tilde{p} \end{bmatrix} = \begin{bmatrix} -\tilde{d} & 1 & 0 & 0 \\ 0 & 0 & -\tilde{s} & 1 \\ -1 & 0 & 1 & 0 \\ 0 & -1 & 0 & 1 \end{bmatrix} \begin{bmatrix} p_{cap} - \tilde{d} \sum_{n=1}^N q_{u_n} \\ \tilde{s} \sum_{n=1}^N q_{w_n} \\ 0 \\ 0 \end{bmatrix}, \quad (8a)$$

where coppersheet supply and demand slopes are:

$$\tilde{s} = \left(\sum_{n=1}^N s_n^{-1} \right)^{-1}, \quad (8b)$$

and

$$\tilde{d} = \left(\sum_{n=1}^N d_n^{-1} \right)^{-1}, \quad (8c)$$

respectively. We assume the must-take and must-serve prices are the same everywhere, e.g., the minimum price of zero and the maximum price of the

265 market cap. With the coppersheet price we obtain the ideal net exports,
 266 $\tilde{\mathbf{e}} = [\tilde{e}_1 \ \cdots \ \tilde{e}_n]^T$, from Eq. (5a).

267 We can find the unconstrained transfer flow solution using the graph
 268 theory framework. The connectivity matrix for an N -area L -line intercon-
 269 nection is:

$$\mathbf{Y} = \begin{bmatrix} y_{(1,1)} & \cdots & y_{(1,L)} \\ \vdots & \ddots & \vdots \\ y_{(N,1)} & \cdots & y_{(N,L)} \end{bmatrix}, \quad (9a)$$

270 where the value for a line l from area n to area m is $y_{(n,l)} = +1$ when $n < m$
 271 and $y_{(n,l)} = -1$ when $n > m$, and $y_{(n,l)} = 0$ when $n = m$ or no line connects
 272 areas n and m . Given the matrix $\mathbf{Y}$ and the ideal net export set $\tilde{\mathbf{e}}$ we can
 273 solve for the unconstrained flows on the L lines:

$$\tilde{\mathbf{f}} = \mathbf{Y}^+ \tilde{\mathbf{e}} = [\tilde{f}_1 \ \cdots \ \tilde{f}_L]^T, \quad (9b)$$

274 where $\mathbf{Y}^+$ is the Penrose pseudo-inverse of $\mathbf{Y}$. Among the possible flow
 275 solutions that result in the ideal net exports, this solution has the smallest
 276 2-norm [23], so arguably the transmission loss is minimum if tielines have
 277 similar loss factors.

278 3.3. Constrained-transfer solution

279 As described above, the maximum global surplus is achieved under a
 280 condition when the exports are those obtained from the coppersheet solution.
 281 This solution may assign a flow to a tieline over its transfer limit. In this
 282 case, we seek a flow set that does not violate transmission constraints but
 283 still results in the ideal net export values. If such a flow set does not exist,
 284 we will seek the flow set that results in a global surplus as close to the
 285 maximum surplus as possible. The objective function can be rewritten as:

$$\min_{\mathbf{e}} \mathbf{e}^T \boldsymbol{\Omega} \mathbf{e} = \min_{\mathbf{f}} (\mathbf{Y} \mathbf{f})^T \boldsymbol{\Omega} (\mathbf{Y} \mathbf{f}), \quad (10a)$$

286 subject to:

$$\mathbf{f}_{\min} \leq \mathbf{f} \leq \mathbf{f}_{\max}, \quad (10b)$$

287 where $\boldsymbol{\Omega}$ is the $N \times N$ diagonal matrix of $[\omega_1 \ \cdots \ \omega_N]$. In any feasible
 288 solution, as long as there is a price gradient on a tieline its associated transfer
 289 flow equals its limit:

$$f_{n \rightarrow m} = \begin{cases} f_{n \rightarrow m_{\min}} & \text{for } p_m < p_n, \\ f_{n \rightarrow m_{\max}} & \text{for } p_m > p_n. \end{cases} \quad (10c)$$

290 The price gradient vector $\delta \mathbf{p}$ is obtained from:

$$\delta \mathbf{p} = -\mathbf{Y}^T \mathbf{p}, \quad (10d)$$

291 where $\mathbf{p}$ is the price vector, calculated from (see Appendix 1):

$$\mathbf{p} = \mathbf{p}_0 - \mathbf{\Omega} \mathbf{e} = \mathbf{p}_0 - \mathbf{\Omega} \mathbf{Y} \mathbf{f}. \quad (10e)$$

292 We use a sequential quadratic programming (SQP) method [24] imple-
 293 mented by Matlab’s optimization toolbox function `fmincon` [25] to solve this
 294 optimization problem and determine the optimum flow set. The objective
 295 function is convex, and also the objective and constraints are differentiable
 296 functions, thus the solution to the optimization is the global optimum [26].
 297 Perhaps a good initial point to feed into the solver is the coppersheet solution
 298 with overloaded tielines adjusted to their capacity limits.

299 4. Western Interconnection

300 In this section, we present an interconnected system model that loosely
 301 represents the Western Interconnection. The WECC system extends from
 302 Canada to Mexico and includes the provinces of Alberta and British Columbia
 303 in Canada, the northern portion of Baja California in Mexico, and all or por-
 304 tions of 14 western US states. As of March 2016, there are 38 control areas
 305 (balancing authorities) in the WECC system [27]. California and Alberta
 306 are the only regions with full energy markets in the interconnection.

307 4.1. Bulk system model

308 A 20-area reduced model of the WECC system, illustrated in Fig. 6, is
 309 built by combining two or more balancing authorities into one consolidated
 310 area. The system interties (groups of transmission lines) are assumed loss-
 311 less. The intertie transfer limits are given in Appendix 2, estimated from
 312 the WECC 2024 common case [28]. In this model, the internal transmission
 313 constraints within the control areas are ignored, although area demand is
 314 scaled up by a constant factor that approximately accounts for these losses.
 315 The peak load and annual energy consumption forecasts as well as the in-
 316 ternal loss factors are provided in Table 4, extracted from the WECC 2024
 317 common case [28]. Intermittent (wind, solar and run-of-river hydro), base
 318 and dispatchable generation capacities are given in Table 5 also from the
 319 WECC 2024 common case.

Fig. 6: The bubble pipeline view of the 20-consolidated area WECC model.

4.2. Market model

We assign a hypothetical market to every consolidated area. The supply curve consists of a flat segment for must-take generators (wind, solar, run-of-river hydro, biomass, geothermal and nuclear units), and a variant segment for dispatchable generators (coal-fired, hydro and gas-fired units). The hourly power generation of intermittent generation resources (wind, solar and run-of-river) are extracted from the WECC 2024 common case. Once constructed, there is effectively no marginal cost of producing renewable energy, thus it will produce at a price as low 0 \$/MWh. We also assign a price of 0 \$/MWh to 15% of hydro capacity, 50% of coal capacity and all of nuclear capacity so that they will be treated as a must-take resource because once started these generators are costly to shut down and thus exhibit

Table 4: Demand forecast and internal loss data in 2024

Area number	Consolidated area	Peak [MW]	Energy [GWh/year]	Loss factor
1	AESO	16095	115061	1.019
2	BCH	12542	69326	1.020
3	PNW = AVA + BPA + CHPD + DOPD + GCPD + PACW + PGE + PSEI + SCL + TPWR	33384	184103	1.025
4	NWMT	1898	12163	1.023
5	PAWY	1681	11028	1.013
6	NCA = BANC + CIPB + CIPV + TIDC	30626	144848	1.043
7	SPPC	2447	15784	1.026
8	ID = IPFE + IPMV + IPTV	4157	19290	1.036
9	UT = PAID + PAUT	8443	39362	1.028
10	CO = WACM + WAUW	5867	34863	1.023
11	LDWP	7789	34129	1.027
12	NEVP	7034	30083	1.045
13	PSCO	8130	41027	1.028
14	SCA = CISC + VEA	26847	119573	1.040
15	AZ = AZPS + SRP + TEPC + WALC	23596	109534	1.026
16	CISD	5573	26702	1.037
17	IID	1342	4836	1.043
18	PNM	3136	16449	1.026
19	CEF	3255	15452	1.033
20	EPE	2391	11106	1.032

332 a negative marginal cost of operation below these levels.

333 For simplicity we assume that the variant segment is linear, and the
334 bidding prices of the cheapest and most expensive dispatchable units are
335 the same as the must-take (zero) and must-serve (here 500 \$/MWh) prices,
336 respectively. Note that must-take units operate continuously (except during
337 curtailment hours) so their start-up and shut-down costs are not considered.
338 In addition, for simplicity, the start-up and shut-down costs of dispatchable
339 units are not currently considered in the model.

340 Similarly, the demand curve consists of an unresponsive segment for
341 must-serve loads and a responsive segment for deferrable loads such as water
342 heaters, electric vehicles, heating, ventilation and air conditioning loads.
343 The responsive load can respond to the market price such that it is zero when
344 price is at the market cap, and is all-in when price is zero. A simple demand

Table 5: Supply data (aggregated installed capacity) in 2024

Area	Non-dispatchable (must-take) generation		Dispatchable generation [MW]
	Intermittent [MW]	Base (invariable) [MW]	
AESO	2275.2	3710	17733
BCH	815.3	3531	17000
PNW	14432.0	5845	36675
NWMT	664.2	1227	1993
PAWY	1315.3	1648	2105
NCA	5092.7	5351	38684
SPPC	800.0	1118	3287
ID	660.3	374	2845
UT	256.5	2183	8136
CO	656.4	1807	4310
LDWP	687.0	89	8727
NEVP	75.7	426	13085
PSCO	2441.1	1616	11645
SCA	6028.1	977	28645
AZ	3220.6	8601	39353
CISD	432.8	34	8558
IID	34.4	1170	1514
PNM	840.3	910	4504
CFE	384.2	697	6600
EPE	1.3	0	3512

model is developed to obtain the hourly responsive load function. Given that the wide variety of demand response functions available in literature can all be linearized in the neighborhood of the operating point, a linear model of demand is chosen for the multi-area resource allocation focus of this study.

The hourly demand forecast q_h in every balancing authority is available in the WECC 2024 common case. A portion of q_h is flexible and potentially responsive to the market price, and the remainder is unresponsive. For simplicity, we assume the relative magnitude of the unresponsive portion, $\alpha = \frac{q_u}{q_h}$, remains constant over the entire year. To approximate the responsive demand, we make the additional assumption that responsive load is linearly sensitive to the price fluctuation in a 4-hour future time window. If the average of inelastic-demand clearing prices over a 4-hour future time window (from a 4-hour ahead forecast) is less than the inelastic-demand clearing price at a given hour, then the cleared elastic demand will be lower than the inelastic demand. The motivation behind this behavior is driven by the opportunity to postpone a proportion of responsive load in order to

362 take advantage of lower prices within the next 4 hours.

363 Consider $\bar{p}$ is the price at which the cleared quantity of the elastic and
 364 inelastic demands are equal. We assume $\bar{p}$ is equal to the average of esti-
 365 mated inelastic-demand clearing prices in a 4-hour future time window. If
 366 the hourly price is equal to the average price, there is no economic incen-
 367 tive to adjust flexible loads. Using a linear demand curve, the maximum
 368 responsive load is:

$$q_r = \frac{(1 - \alpha) p_{cap}}{p_{cap} - \bar{p}} q_h. \quad (11)$$

369 Fig. 7 shows an hour at which must-take generation, inelastic demand
 370 and the associated price are 1000 MW, 3250 MW and 321 \$/MWh, re-
 371 spectively. Consider the case for which the forecast shows the must-take
 372 generation will increase to 1500 MW after one hour, 2000 MW after two
 373 hours and 2500 MW after three hours, therefore the associated prices will
 374 be 250 \$/MWh, 179 \$/MWh and 107 \$/MWh, respectively if the demand
 375 remains constant. The average price of these four hours is 214 \$/MWh.
 376 Assuming 80% of the demand is inelastic, then according to the model if the
 377 hour inelastic-demand price were 214 \$/MWh, the elastic demand quantity
 378 would be the same as the inelastic demand quantity (3250 MW). Because
 379 the hourly price (321 \$/MWh) is greater than the average price, the re-
 380 sponsive load adjusts such that the clearing price and cleared quantity are
 381 295 (< 321) \$/MWh and 3066 (< 3250) MW, respectively. This demand
 382 function gives an approximately constant energy consumption model over a
 383 4-hour window.

384 Although it may seem that a relatively large fraction of the demand
 385 is responsive, the active responsive demand is typically a smaller fraction.
 386 The dispatched quantity of the responsive demand is implicitly restricted
 387 between the quantities associated with the cheapest and the most expensive
 388 prices estimated in a 4 hour future time window, not between zero and q_r .
 389 This restriction avoids the load control saturation and oscillation observed
 390 in some studies of short-term dispatchable demand response [29, 30, 31].

391 5. Results and discussion

392 We evaluate the proposed scheduling method on the reduced WECC
 393 baseline model for each 8784 hours of the year 2024. First, a simulation is
 394 performed assuming the demand is completely inelastic. Second, another
 395 simulation is carried out for a case in which 5% of demand is price sensitive.
 396 To set up the responsive demand functions, the 4-hour rolling average prices

Fig. 7: Responsive load shape example.

(in each area) are gathered from the first simulation and used in the second one. All presented figures are from the second simulation with the transfer constraint limits set to 75% of the rated transfer capacity. Finally, several simulations are performed to explore the impact of various levels of demand response, and of relaxation of the transfer constraint limit on global cost.

5.1. Inelastic demand

The simulation results, excluding demand response, show that the unconstrained and the constrained transfer solutions decrease the global electricity production cost (and correspondingly increase the global surplus) by \$12.30B and \$ 10.67B per year, respectively, when compared with the standalone condition case. This cost reduction is equal to 25% and 22% of the standalone production cost respectively. The \$12.30B reduction is the difference between the two extreme coppersheet and standalone conditions. In WECC and many other jurisdictions, balancing authorities exchange electricity according to long-term and short-term bilateral contracts. Therefore, without the proposed unified operation the production cost is lower than the standalone condition case. In addition, in the model, we assume hydro (up to 15% of total nominal capacity) and baseload thermal (up to 50% of total nominal capacity) power plants are treated as must-take resources (base generation) to satisfy operational constraints. Thus, the reported percentage of cost saving, which is the cost reduction divided to the total cost is

over-estimated because its denominator excludes a portion of the operation cost.

Table 6 compares the producer cost reduction and surplus reduction in each consolidated area under unconstrained and constrained solutions. Negative cost reduction indicates an increase in production cost in that area. We note that although the magnitude of the decreased producer surplus is greater than the magnitude of the decreased production cost in many consolidated areas, the magnitude of the total surplus reduction is smaller than the magnitude of the total cost reduction.

Table 6: Producer cost and surplus reduction for 100% inelastic demand for 2024 (in M\$/year)

	Producer cost reduction		Producer surplus reduction	
	Unconstrained	Constrained	Unconstrained	Constrained
AESO	6642	1797	11421	2820
BCH	55	149	79	284
PNW	35	479	-552	588
NWMT	-260	-236	-1622	-1516
PAWY	-297	-246	-2513	-2132
NCA	-393	121	-817	145
SPPC	-297	-254	-1058	-933
ID	1873	1907	2630	2696
UT	453	557	763	997
CO	1244	1296	2978	3147
LDWP	2304	2422	2498	2632
NEVP	-183	-4	-214	-8
PSCO	-454	-306	-1044	-753
SCA	5697	6083	7215	7771
AZ	-4624	-4082	-12111	-10968
CISD	992	1108	1061	1187
IID	-213	-192	-1467	-1375
PNM	-324	-262	-873	-735
CFE	-521	-287	-873	-506
EPE	573	622	573	622
Total	12301	10671	6075	3965

5.2. Elastic demand

Coppersheet condition

Fig. 8 illustrates the aggregated hourly demand with 5% responsive fraction, intermittent generation and base generation (both must-take) in the summer peak month of July and the winter peak month of December 2024.

Fig. 8: Coppersheet demand, must-take and associated prices.

432 In addition, the net demand, which is the difference between the aggregated
 433 demand and the must-take generation is illustrated. The color of the net
 434 demand represents the associated coppersheet price. Notice that dispatch-
 435 able generation is also equal to the net demand. As expected, smaller net
 436 demand is associated with lower prices.

437 Fig. 9 shows the maximum global cost reduction (relative to standalone
 438 global cost) versus the standard deviation of standalone prices (for each of

Fig. 9: Global cost reduction vs. standard deviation of standalone prices for each hour.

8784 hours in the year 2024). Negative prices are considered zero when computing the standard deviation. The color represents the associated coppersheet price. A larger standard deviation value indicates a greater resource diversity, which usually creates a greater opportunity to reduce the production cost by exchanging power within the interconnection.

Constrained transfer condition

Fig. 10 illustrates fluctuations of the hourly global cost reduction under both the unconstrained and the constrained transfer conditions in July and December 2024. Clearly, the cost reduction is strongly correlated with demand. The color represents the *economic utilization factor*, which is a proposed performance index for the transmission system defines as the ratio of the cost reduction associated with the constrained transfer solution to the cost reduction associated with the unconstrained transfer solution on an hourly basis. We note that there is a greater opportunity to reduce the production cost in December than in July, despite the lower aggregate demand in December. The reason is the magnitude of net demand is more diverse over the system in winter than in summer. In other words, the relatively lower demand in winter enables some areas to feed cheap electricity to the rest of the system, so other areas do not schedule their more expensive units. However, because of transfer constraints the coppersheet

Fig. 10: Global hourly cost reduction.

459 export/import schedule is not usually achievable in December, thus the eco-
 460 nomic utilization factor in December is considerably lower than in July.

461 Fig. 11 shows a set of the “economic utilization factor” and the “stan-
 462 dard deviation of clearing price over areas” pairs. The utopia point is at
 463 the top left corner, where the clearing price is uniform over the entire in-
 464 terconnection. As the standard deviation approaches zero, the economic
 465 utilization factor increases. The color represents the mean value of clearing

Fig. 11: Economic utilization factor vs. price standard deviation.

prices.

Fig. 12 shows the optimal transfer set at the system peak hour. The node color represents the price associated with the standalone condition, which varies between 0 \$/MWh and 500 \$/MWh with a standard deviation of 124 \$/MWh. Because of the electricity exchange, the clearing price decreases in importing areas and increases in exporting areas. In the peak hour, the clearing price in AESO decreases to 251 \$/MWh, in BCH and CFE increases to 251 \$/MWh and 236 \$/MWh respectively, and in the rest of the system becomes 241 \$/MWh. Consequently, suppliers will gather less surplus in importing and more surplus in exporting areas in comparison to the standalone condition. The magnitude of the decreased surplus in importing areas is greater than the magnitude of increased surplus in exporting areas thus sharing generators decreases the overall producer surplus.

Table 7 compares the production cost per unit associated with the standalone and the constrained transfer solutions in every consolidated area for the 100% and the 95% inelastic demand conditions. In general, the production cost per unit decreases in importer-areas, and increases in exporter-areas. Table 7 indicates that demand response does not reduce the production cost per unit notably. Without demand response, the average production cost under the standalone and the constrained transfer solutions are 41.96 \$/MWh and 33.40 \$/MWh, respectively. With 5% demand response,

Fig. 12: Optimal transfer flow solution at the system peak hour.

the average production cost under the standalone and the constrained transfer solutions are 41.95 \$/MWh and 33.39 \$/MWh, respectively. Notice that the electricity production cost is very low in consolidated areas with a significant amount of must-take generators in some hours.

5.3. British Columbia

We now illustrate the impact of optimal scheduling on British Columbia's export/import schedule. British Columbia's hydro-dominated grid connects Alberta's fossil-dominated grid to the rest of the WECC system. Hydroelectric storage assets in British Columbia can also provide the reserves needed to help WECC integrate a significant amount of intermittent renewables in the future.

Fig. 13 illustrates the load duration curve of the Pacific Northwest–British Columbia tieline. The color represents the price difference. The positive direction is from Pacific Northwest to British Columbia, with positive price difference as the British Columbia price minus the Pacific Northwest price. The price difference is zero when the transfer flow is not at

Table 7: Production cost per unit in \$/MWh

	Standalone		Constrained	
	100% inelastic	95% inelastic	100% inelastic	95% inelastic
AESO	78.48	78.47	67.51	67.50
BCH	32.72	32.71	31.31	31.30
PNW	26.33	26.31	24.64	24.63
NWMT	1.45	1.44	14.78	14.77
PAWY	0.00	0.00	11.11	11.10
NCA	32.14	32.13	31.68	31.67
SPPC	9.76	9.75	21.29	21.28
ID	109.06	109.07	32.83	32.79
UT	35.66	35.62	26.92	26.91
CO	50.93	50.92	19.19	19.18
LDWP	97.06	97.04	51.01	51.01
NEVP	49.45	49.44	49.91	49.90
PSCO	26.24	26.23	31.62	31.61
SCA	76.38	76.37	41.27	41.26
AZ	6.11	6.11	28.10	28.09
CISD	79.17	79.17	52.90	52.90
IID	0.01	0.01	13.82	13.81
PNM	16.58	16.57	27.71	27.71
CFE	21.43	21.43	33.10	33.11
EPE	90.20	90.19	57.33	57.33
Average	41.96	41.95	33.40	33.39

its limits, because the neighboring area prices will naturally equilibrate due to the power transfer. As shown, British Columbia exports a significant amount of the imported electricity (820-900 MW) to Alberta. The positive direction of the Alberta–British Columbia tieline is from Alberta to British Columbia, with positive price difference as the British Columbia price minus the Alberta price. The optimal solution suggests that the Alberta–British Columbia tieline is usually operated under the full transfer capacity (900 MW), and as a result there is a price gradient on this tieline. Therefore British Columbia has an arbitrage opportunity buying relatively cheaper electricity from the US to sell to Alberta.

Fig. 14 shows the surplus increase as a function of the net export in British Columbia. The shape of this curve should be a parabola according to Eq. (7c), which is verified in the figure. The color represents the clearing price.

Fig. 13: Load duration curve of the Pacific Northwest–British Columbia and the Alberta–British Columbia tielines.

Fig. 14: Surplus increase in British Columbia.

518 5.4. Sensitivity analysis

519 The model presented belongs to a class of agent-based models for which
520 validation can be challenging [32]. Validation methods include the usual sta-
521 tistical, behavior, and structural validation, as well as so-called *face* valida-
522 tion in which experts observe the response of the system to various scenarios
523 to consider whether the model exhibits the expected local and global prop-
524 erties and sensitivities. In spite of these challenges, agent-based models are
525 particularly well-suited for the study of transient dynamics in highly com-
526 plex hybrid econo-physical systems such as smart-grids [33]. If the model

behaves in the same way as the physics of the problem dictates, the model can be a useful tool that provides insight to the system behavior [34].

For the proposed model we expect that (i) upgrading the transmission system and (ii) integrating demand response result in a greater cost reduction. Table 8 confirms this expectation: as the intertie constraints are relaxed the global cost decreases. The same trend is also observed when the fraction of responsive demand increases significantly. However, the economic benefit of introducing inter-hourly demand response is not substantial when the system is operated with the optimal inter-area transfer set. The rational behind this is that the optimal transfer set has already adjusted to price fluctuations (as much as the transmission system allows); hence the remaining opportunity for demand response to react is very limited. If we used a more flexible demand curve such as that presented in previous studies by the authors [35, 36], the impact of demand response would be potentially greater, but probably still not comparable with the impact of the optimal interchange transfer.

Table 8: Global cost reduction

Demand response	75% transfer limit [B\$]	90% transfer limit [B\$]	105% transfer limit [B\$]	Copper-sheet [B\$]
0%	10.67	10.85	11.01	12.30
1%	10.68	10.86	11.02	12.31
5%	10.70	10.88	11.04	12.33
10%	10.72	10.91	11.06	12.35
20%	10.77	10.95	11.10	12.39
50%	10.85	11.04	11.19	12.48

Relaxation of the transfer limit from 75% to 90% (even to 105%) does not provide a significant additional cost reduction, in comparison to the achievable benefit from operating the system under optimal inter-area transfer set (relative to standalone case). Some tielines probably need major upgrades, but most have sufficient transfer capacity at least for the WECC 2024 scenario studied. This finding highlights the great cost reduction opportunity that exists in operating the interconnection in an unified manner with the existing transmission capacity. This opportunity is more appreciable with greater penetration levels of intermittent renewables in the future. Operating the system in an economically efficient manner enables the interconnection to meet its greenhouse gas emissions reduction targets with a relatively moderate incremental cost. Although technical and non-technical barriers make a unified scheduling and dispatch control challenging, distributed dis-

patch control strategies exist that can provide sub-optimal inter-area transfer sets.

Optimizing the interchange transfer effectively depresses the clearing price by sharing low-cost generation units over the interconnection. Consequently, the expensive peak units are dispatched less frequently and the annual producer surplus decreases. Table 9 indicates the global producer surplus reduction for different limits of transfer constraint and levels of demand response. For example, under the 75% limit of transfer constraint and 5% demand response, this reduction is 4% of the global producer surplus. In general we find that optimal scheduling decreases producer surplus which may have an adverse economic impact both on operators that rely on congestion revenues and zero marginal-cost generation units that must recover capital costs.

Table 9: Global producer surplus reduction

Demand response	75% transfer limit [B\$]	90% transfer limit [B\$]	105% transfer limit [B\$]	Copper-sheet [B\$]
0%	3.96	4.07	4.26	6.07
1%	3.97	4.07	4.27	6.08
5%	4.00	4.10	4.30	6.11
10%	4.03	4.13	4.33	6.14
20%	4.08	4.18	4.38	6.19
50%	4.19	4.29	4.49	6.30

6. Conclusions

In this paper we have presented a method to model the limits and optimal generation and demand response allocation for the hourly schedule problem. The purpose is not to solve the interconnection resource allocation problem itself. Rather we seek to provide a method that facilitates impact studies of renewable generation and demand response interaction at the interconnection scale without fully implementing the various market designs extant.

Accordingly a new resource allocation modeling method that incorporates both energy supply and demand response resource is presented. This method is used to model the interconnection-scale scheduling problem in the Western Electricity Coordinating Council (WECC) system planning year 2024. We quantify the potential benefits of demand response integration in WECC using the proposed surplus-maximizing scheduling model considering tieline transfer limits on an hourly basis. The method determines the

584 optimal inter-area transfer set that effectively makes the clearing price uni-
585 form over the interconnection’s markets (as much as possible). The overall
586 consumer surplus increases and the overall producer surplus decreases, while
587 the increased magnitude is always greater than the decreased magnitude. At
588 the same time, the magnitude of production cost decrease is greater than
589 the magnitude of produce surplus decrease. Results show that inter-regional
590 collaboration assist control areas in reducing production cost by \$10.67B,
591 equal to 22% relative to the standalone condition with inelastic demand. In
592 addition, integration of 5% demand response provides an additional \$27M
593 cost saving. However, we also conclude that economic benefit of inter-hourly
594 demand response is not substantial when the system is operated with the
595 optimal inter-area transfer set, which suggests that the majority of the ben-
596 efits for demand response arise from intra-hourly demand response resources
597 which are not considered in conventional hourly resource scheduling mech-
598 anisms.

599 The hourly supply and demand resource commitments found in this pa-
600 per can be used to establish a 5-minute redispatch market in each balancing
601 authority to provide reliable and efficient short-term matching of generation
602 and load resources. Suitable control systems are needed to enable demand
603 response participation in redispatch markets and ultimately in the ancillary
604 services markets for frequency [37] and voltage regulation [38].

605 Future work will apply the proposed scheduling method for energy plan-
606 ning purposes for renewable energy policy studies in the Western Intercon-
607 nection beyond the year 2024. The objective will be to determine the most
608 economically beneficial type and capacity of renewable energies in each re-
609 gion such that the interconnection can achieve a target level of greenhouse
610 gas emissions reduction.

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Appendix 1: Objective function

Under the standalone condition, supply and demand quantities are equal, so the clearing price in control area n is:

$$p_{0n} = \frac{s_n p_{max} - d_n p_{min}}{s_n - d_n} + \frac{s_n d_n}{s_n - d_n} (q_{w_n} - q_{u_n}).$$

For a non-zero net export $e_n = q_{s_n} - q_{d_n}$, the demand price is equal to the supply price:

$$\underbrace{d_n (q_{d_n} - q_{u_n}) + p_{max}}_{p_{d_n}} = \underbrace{s_n (q_{s_n} - q_{w_n}) + p_{min}}_{p_{s_n}} = s_n \underbrace{(q_{d_n} + e_n - q_{w_n})}_{q_{s_n}} + p_{min},$$

therefore the demand quantity is:

$$q_{d_n} = \frac{p_{max} - p_{min}}{s_n - d_n} + \frac{s_n q_w - d_n q_u}{s_n - d_n} - \frac{s_n}{s_n - d_n} e_n,$$

and the clearing price is:

$$p_{c_n} = \underbrace{\frac{s_n p_{max} - d_n p_{min}}{s_n - d_n} + \frac{s_n d_n}{s_n - d_n} (q_{w_n} - q_{u_n})}_{p_{0n}} - \frac{s_n d_n}{s_n - d_n} e_n = p_{0n} - \omega_n e_n,$$

so the price vector is:

$$\mathbf{p} = \mathbf{p}_0 - \mathbf{\Omega} \mathbf{e}.$$

Accordingly, Eq. (7a) can be rewritten as:

$$\max \frac{-1}{2} \sum_{n=1}^N \omega_n e_n^2 \equiv \min \frac{1}{2} \sum_{n=1}^N \omega_n e_n^2.$$

Appendix 2: WECC intertie transfer capacity

Path number	From area	To area	Minimum [MW]	Maximum [MW]
P01	AESO	BCH	-1200	1000
P03	PNW	BCH	-3150	3000
P08	NWMT	PNW	-2150	3000
P09	NWMT	CO	-2573	2573
P14	ID	PNW	-2250	3400
P16	ID	SPPC	-360	500
P18	NWMT	ID	-256	337
P20	ID	UT	-2250	2250
P22	PNM	AZ	-2325	2325
P24	NCA	SPPC	-150	160
P26	NCA	SCA	-3000	4000
P27	UT	LDWP	-1400	2400
P30	UT	PSCO	-650	650
P31	PSCO	PNM	-690	690
P32	SPPC	UT	-235	440
P35	UT	NEVP	-580	600
P36	CO	PSCO	-1680	1680
P42	IID	SCA	-1500	1500
P43	LDWP	SCA	-4000	4000
P44	CISD	SCA	-2500	2500
P45	CISD	CFE	-800	400
P46N	NEVP	LDWP	-6000	6000
P46S	NEVP	SCA	-5000	5000
P47	EPE	AZ	-1048	1048
P48	EPE	PNM	-1970	1970
P49	AZ	NEVP	-10200	10200
P59	AZ	SCA	-218	218
P65	PNW	LDWP	-3100	3220
P66	PNW	NCA	-3675	4800
P76	PNW	SPPC	-300	300
P78	UT	PNM	-600	600
P79	AZ	UT	-300	265
P80	NWMT	PAWY	-600	600
PP1	PAWY	UT	-1700	1700
PP2	IID	CISD	-150	150
PP3	AZ	CISD	-1160	1650
PP4	AZ	IID	-160	260

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