Supplement to the paper

"Intraday markets, wind integration and uplift payments in a regional U.S. power system"

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This supplement contains additional data and results for the paper "Intraday markets, wind integration and uplift payments in a regional U.S. power system". Section A provides a list of figures not presented in the paper: Figure A1 shows the level of historic uplift payments for several RTOs in the U.S. over the past ten years; Figure A2 presents the 36-node electric power system used in our models; Figures A3 and A4 illustrate the solution process for the two-settlement market design model and the multi-settlement market design model, respectively; Figure A5 shows the wind curtailment by zone for the historical High Wind case. Section B provides a list of data tables not included in the paper. Tables B1 and B2 present the unit characteristics for all the generators in our system. Section C presents a detailed description of the data used in our modified test system. Section D shows the formulation for our models. This includes the nomenclature, the model formulation for the day-ahead and real-time stages of the two-settlement, and the formulation for the second intraday market stage of the multi-settlement. Lastly, Section E includes a description of the uplift calculation method used in the paper.

Appendix A: Figures

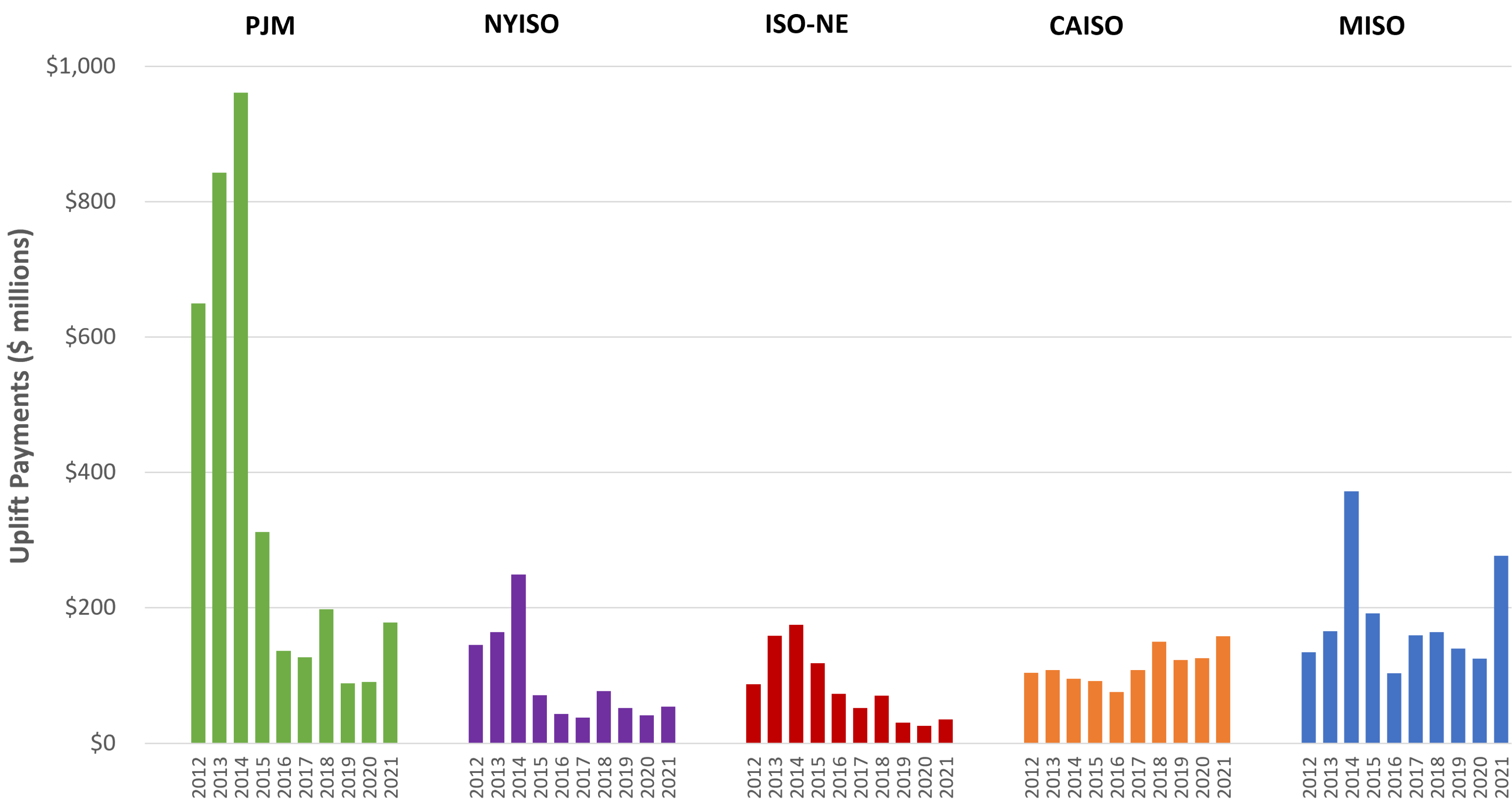

Figure A1: Historic Uplift Payments for each U.S. Electricity Market [1–5]

Note: The spikes in uplift payments in the MISO region during 2014 and 2021 are due to severe winter storms.

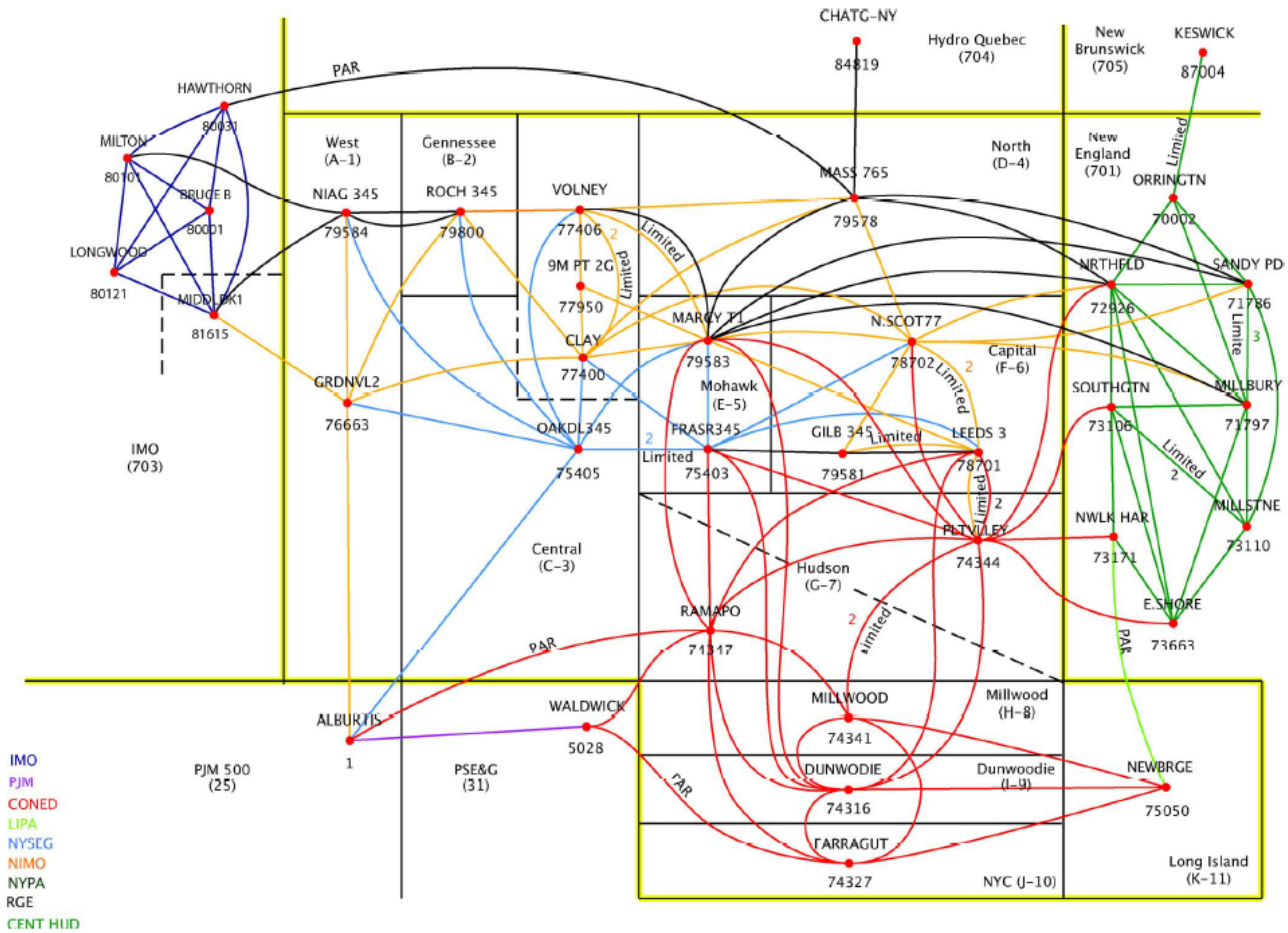

Figure A2: 36-Node Network (based on [6]). Wind generators are located at the following nodes: Orrington, Sandy Pond, Millbury, Northfield, Southington, Millstone, Norwalk Harbor, Millwood, Newbridge, 9-Mile Point, Leeds, Massena, Gilboa, Marcy, Niagara, Rochester, and Alburtis.

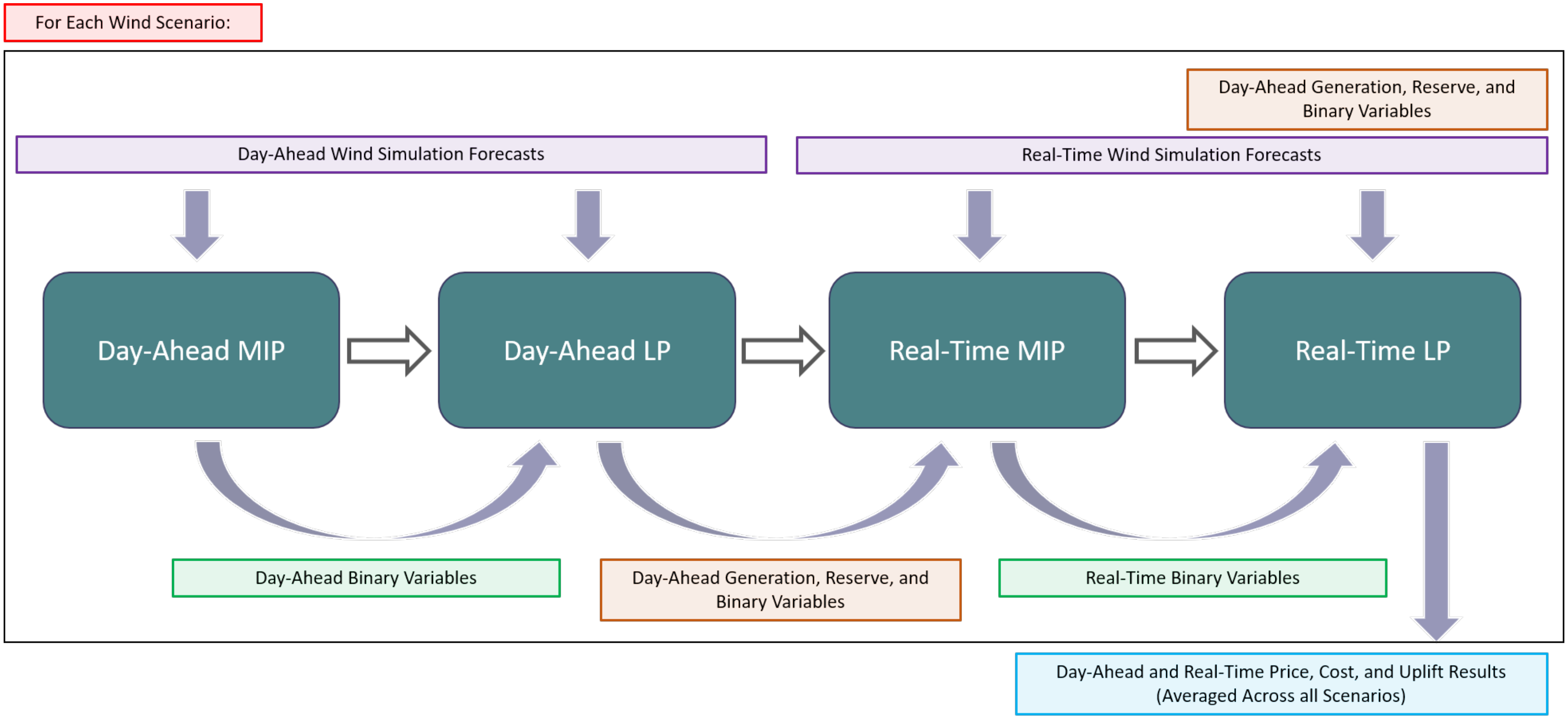

Figure A3: Model Solution Flow - Two-Settlement Market Design

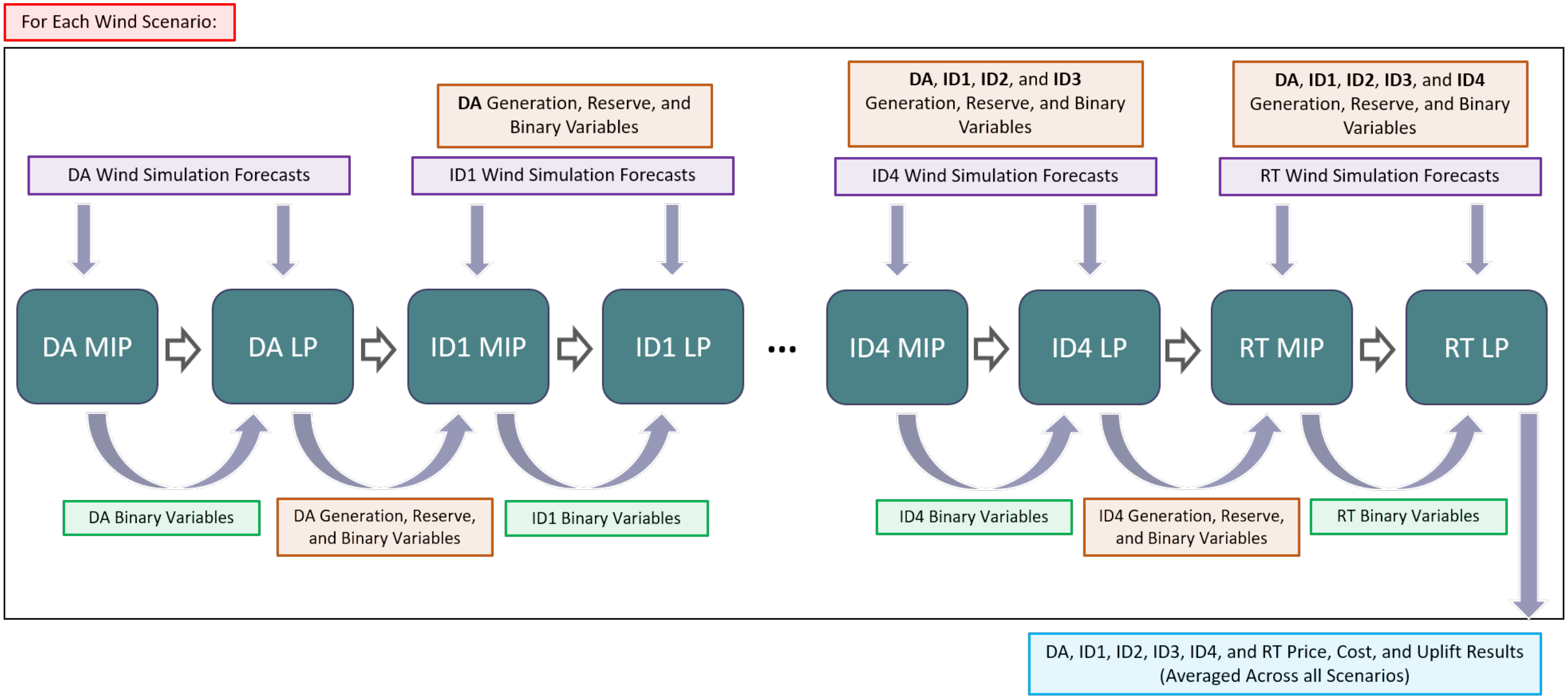

Figure A4: Model Solution Flow - Multi-Settlement Market Design

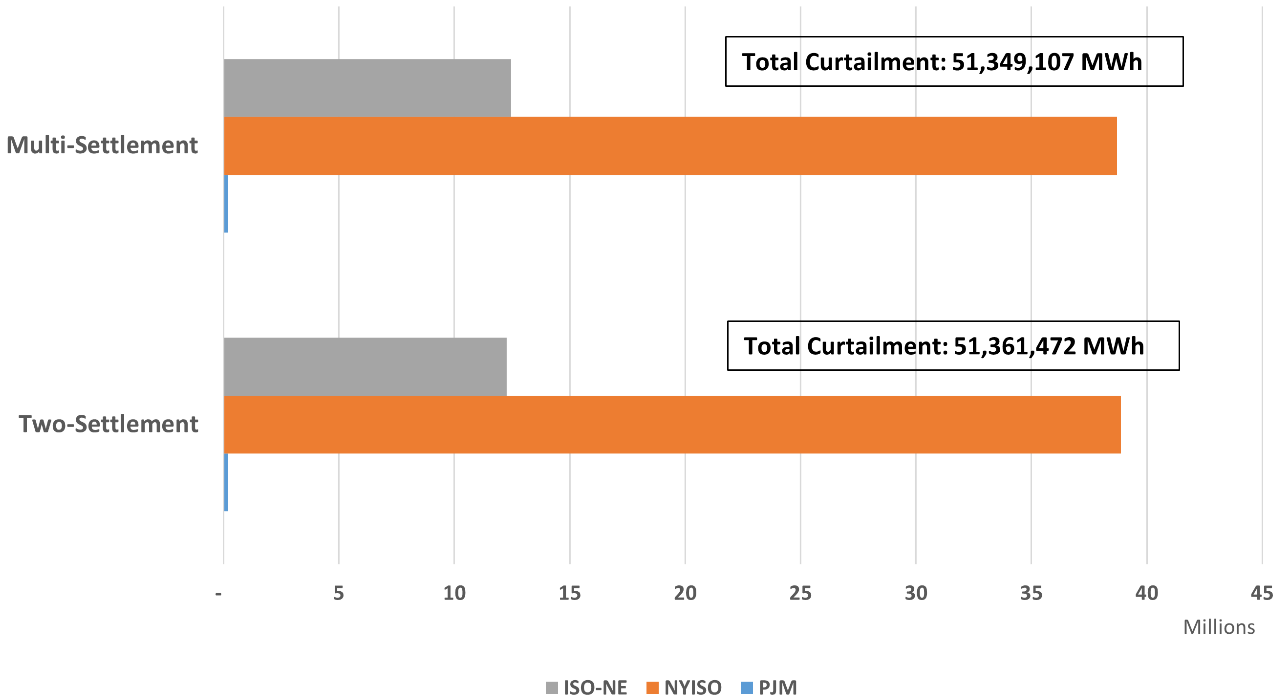

Figure A5: High Wind: Total Wind Curtailment by Zone

Appendix B: Tables

Generator	Marginal Cost ($/MWh) [7]	No-Load Cost ($/MW per Hour) [8] [9]	Min Load (% MW) [10] [11]	SPF (% Cap) [8]
Nuclear - All ISO	26.87	0	88	0
Coal - PJM	35.88	1.10	26	20
Coal - ISO-NE	62.41	1.10	26	20
Coal - NYISO	50.47	1.10	38	20
NGCC - PJM	28.42	4.78	50	50
NGCC - ISO-NE	33.08	4.78	56	50
NGCC - NYISO	34.27	4.78	50	50
NGCT - PJM	55.74	8.86	62	80
NGCT - ISO-NE	49.92	8.86	75	80
NGCT - NYISO	58.10	8.86	62	80
Hydro - PJM	13.97	0	0	80
Hydro - ISO-NE	14.59	0	0	80
Hydro - NYISO	12.19	0	0	80
Oil - PJM	241.97	8.86	62	80
Oil - ISO-NE	238.33	8.86	62	80
Oil - NYISO	221.56	8.86	49	80
Wind - PJM	3.07	N/A	N/A	N/A
Wind - ISO-NE	4.36	N/A	N/A	N/A
Wind - NYISO	3.03	N/A	N/A	N/A

Note: SPF refers to the maximum spinning reserve fraction a generator can provide.

Table B1: Generating Unit Characteristics [7] [10] [11] [8]

Generator	Ramp Up (% Cap/Hr) [8] [12] [13]	Ramp Down (% Cap/Hr) [8] [12] [13]	Start-up Cost ($/MW per Start-up) [8] [14]	Shut-down Cost ($/MW per Shut-down) [8] [14]	Uptime (hr) [11]	Downtime (hr) [11]	Start-up and Notification Time (hr) [11]
Nuclear - All ISO	10	10	N/A	N/A	24	24	N/A
Coal - PJM	35	35	131.35	1.31	8	5	6
Coal - ISO-NE	35	35	131.35	1.31	8	5	6
Coal - NYISO	35	35	131.35	1.31	8	5	6
NGCC - PJM	50	50	61.80	0.62	4	2	4
NGCC - ISO-NE	50	50	61.80	0.62	4	2	4
NGCC - NYISO	50	50	61.80	0.62	4	2	4
NGCT - PJM	100	100	40.60	0.41	1	1	1
NGCT - ISO-NE	100	100	40.60	0.41	1	1	1
NGCT - NYISO	100	100	40.60	0.41	1	1	1
Hydro - PJM	100	100	6.76	6.76	1	1	1
Hydro - ISO-NE	100	100	6.76	6.76	1	1	1
Hydro - NYISO	100	100	6.76	6.76	1	1	1
Oil - PJM	100	100	40.60	0.41	1	1	1
Oil - ISO-NE	100	100	40.60	0.41	1	1	1
Oil - NYISO	100	100	40.60	0.41	1	1	1
Wind - PJM	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wind - ISO-NE	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wind - NYISO	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table B2: Generating Unit Characteristics [7] [10] [11] [8]

Appendix C: Test System

This section provides a detailed description of our test system, which is a modified version of the 36-node electric power system in [6] (Figure A2). Each of the 36 nodes have generation capacity and load, with the exception of the DC line terminal[1] in Quebec at Chateauguay, which is represented as a single hydro generator radially connected to the rest of the Eastern Interconnection. Multiple aggregate generators (each one representing the total capacity of a given technology type) are located at each node. The nodes of the network are connected by 121 high-voltage transmission lines, some of which have limited transmission capacity.

C.1 Generator Data

The network in [6] consists of 77 aggregate generators that differ by fuel and technology type. Each aggregate generator is connected to a node in the network. Total generation capacity by node and RTO zone, along with the generation mix at each node, are given in [6]. Based on these shares, we obtain generation capacity by fuel type at each node. Next, we build gas-fired power plant technology variation (i.e., combined cycle vs gas turbine natural gas plants) into the test system, using data from NYISO and SNL Energy [7, 15]. This enhancement is required because more flexible gas turbines are more likely to respond to changes in output due to wind generation.

Next, we divide all thermal generators (i.e., coal, nuclear, gas, and oil) into individual units, as that allows us to incorporate intertemporal constraints (e.g. start-up costs, minimum output, etc.). To get the number of individual units associated to each node, the capacity of each thermal aggregate generator is divided by the average capacity of generators with that fuel and technology type (found from [7]). This value is then rounded to the nearest whole number, which represents the total number of units of each fuel and technology type. Lastly, the total aggregate generator capacity is divided by the number of individual units to find the new generation capacity of each unit.

An additional modification to the original dataset relates to generators located at nodes representing a "DC Line Terminal", "SVC" or "STATCON" from the 36-node network in [6]. Three static VAR compensators (SVCs) and one static synchronous condenser (STATCON) are present on the NPCC bulk power system in [6], and represented as a generator with no real power output. Since our models use a DC formulation which does not consider reactive power generation, we remove these four zero-output generators. In addition, there are 3 DC lines in the original network. We model the DC line terminals connected to these DC lines as generators which have a constant output over all hours equal to their total capacity.

Finally, we modify the network to include aggregate wind generators at 9 nodes in New York and 7 nodes in New England, as suggested by [16, 17], and 1 node in PJM. ISO-NE provided hourly wind forecast and actual output data for wind plants in their footprint in 2016 and 2017. Forecasts refer to six different look-ahead periods: 24 hours ahead of actual production, 18 hours ahead, 12 hours ahead, 6 hours ahead, 3 hours ahead, and 30 minutes ahead. From the original dataset, we identify a subset of 16 wind generators that have data for at least 90% of the hours in 2016 and 2017. Next, we exclude days with missing hours, leaving 480 days for each generator. Finally, the data are converted from Greenwich Mean Time (GMT) to Eastern Standard Time (EST) and further reduced, leaving only

[1] A DC line terminal represents a node in the network that is connected to a high-voltage DC transmission line.

the days in which all generators have 24 hours of data per day based on EST. The final dataset includes 419 days for 16 wind generators, and is used in the day-ahead, intraday, and real-time wind production forecasts of our models. Each generator is placed at a different node, and one duplicate generator is placed at the PJM node, yielding a total of 17 wind generators in our system.

Generating unit characteristics are provided in Tables B1 and B2. The marginal costs of each generator are calculated by using data from SNL Energy. Heat rate, fuel cost, and heat content data for 2017 are averaged by fuel type, technology type, and RTO. Using these data, we calculate the variable fuel cost by generator technology type for each RTO, assuming wind and hydro plants have a fuel cost equal to zero. Variable non-fuel operations and maintenance costs from SNL are also averaged by fuel type, technology type, and RTO. The variable fuel costs are added to the variable non-fuel operations and maintenance costs to find the total marginal cost by generator technology type for each RTO. We use the average fuel cost and operating cost in [18] to calculate the marginal costs for nuclear plants. The no-load cost data are obtained from [8] and [9]. In our model, we assume that oil plants have the same O&M cost as natural gas combustion turbine (NGCT) plants. Further, minimum generation levels for the coal, natural gas combined cycle (NGCC), NGCT, and oil plants come from [10], where oil plants are assumed to have the same limits as NGCT plants. This report shows the minimum electricity production levels as an estimated percentage of total generator capacity for steam turbine, combined cycle, and combustion turbine technologies. These average percentages are also split up by the heat rate of each plant type. Using SNL Energy, we find the average heat rate during 2008 for each plant type and RTO region. Then, the minimum generation levels for all plants are found by multiplying the relevant percentage, which is based on the heat rate and regional location of a plant, by their total generation capacity. In addition, the minimum generation level for nuclear plants comes from [11] and hydro plants are assumed to a minimum generation level of 0. Finally, the maximum spinning reserve fraction that generators are able to procure comes from [8] and represents a percentage of total capacity for each generator technology type.

Ramp rates are gathered from several sources for the generator technology types in our model. Coal, NGCC, NGCT, and oil plants use the ramping limits from [8], where oil plants are assumed to have the same limits as NGCT plants. These limits represent typical one-hour ramps for each type of generator. The ramp rates for nuclear and hydro plants come from [12] and [13] respectively, which provide information on the typical ramp limits for nuclear and hydro generators.[2] Regarding unit startup and shutdown costs, data for coal, NGCC, NGCT, and oil plants are obtained from [8], where oil plants are assumed to have the same costs as NGCT plants. Additionally, data for hydro plants are obtained from [14]. Nuclear plants are assumed to be "must run" and thus have no applicable startup or shutdown costs. Next, minimum uptime and downtime data are obtained from [11], where oil and hydro plants are assumed to have the same limits as NGCT plants. Lastly, we include the start-up and notification times for all plants, which represents the amount of time a generator requires to start-up and how far in advance they need to be notified to update their commitment decisions.

[2] A more detailed analysis on the hydropower resources in Quebec is discussed in [19], where seasonality of water availability limits plant flexibility. Future work could investigate how less flexible hydro technologies change the outcomes of our model.

C.2 Transmission Data

The NPCC electric test system in [6] includes 121 high-voltage transmission lines connecting node pairs. The original data include 8 instances of duplicate lines (i.e., lines connecting the same node pairs) and 2 instances of three lines connecting the same node pairs. These instances represent parallel lines, where each line is characterized by a different MW transmission capacity. Transmission capacity data and reactances for each line are obtained from [6]. All transmission lines in our study use the original capacity data except for those connecting to the Long Island node, which is a severely constrained area. These line capacities have been tripled to relieve congestion surrounding this node and prevent high price spikes caused by energy scarcity. Our model formulation uses power transmission distribution factors (PTDFs), which are calculated from the reactances using the method described in [20].

C.3 Load and Reserve Requirement Data

Load data at each node in the NPCC system presented in [6] refer to a peak hour in summer 2007. However, our simulations require hourly load for multiple days. We use data from FERC Form 714 [21] to create a yearly load profile for PJM, NYISO, and ISO-NE in 2007. Next, we transform the FERC Form 714 load profile data as follows. Within each RTO, the peak hour load from FERC Form 714 is divided by the annual load from [6]; this creates an RTO-specific scaling factor between the FERC Form 714 load data and the original data provided by [6]. The scaling factor is then applied to the FERC Form 714 load data to create a scaled version of the 2007 hourly load profile for each RTO. Finally, the scaled RTO load profiles are applied to the specific nodes, assuming that the share of load at each node (over the total RTO load) is the same as in [6]. We run our models for different representative days (as discussed in Section 3 of the paper), and the 24-hour load profiles associated to these days are used for the day-ahead, intraday, and real-time data. It should be noted that, while the model formulation is written to be general, the load profiles in the day-ahead, intraday, and real-time market stages are assumed to be the same for a representative day. As a result, any difference in the day-ahead, intraday, and real-time net load (i.e., load minus wind production) is caused by the difference between the wind production forecasts at each stage.

Reserve requirement levels vary by hour of the day, depending on the system load. In line with the literature (e.g., [22]), the total spinning reserve requirement for the whole system is set to a percentage (10%) of the total system load for each hour of the day. Since load is assumed to be the same in the day-ahead, intraday, and real-time markets, the reserve requirement levels are also the same for all stages.

Appendix D: Model Formulation

D.1 Nomenclature

Sets

H	Set of hours
H^{ψ_2}	Set of hours from intraday market 2 (hours 5 - 23)
I	Set of nodes
J	Set of all generators
J_i	Set of generators at node i
J_i^f	Set of fast-start generators at node i - includes oil, gas combustion turbine, and hydro plants
J_i^{nw}	Set of non-wind generators at node i
J_i^s	Set of slow-start generators at node i - includes gas combined cycle, coal, and nuclear plants
J_i^w	Set of wind generators at node i
J_i^n	Set of nuclear generators at node i
J_i^c	Set of coal generators at node i
J_i^{cc}	Set of gas combined cycle generators at node i
L	Set of transmission lines
S	Set of all intraday and real-time market stages (excludes the day-ahead stage)
Φ	Day-ahead designation
Ψ_2	Intraday market 2 designation
Ω	Real-time designation

Parameters

D_{ih}^{ϕ}	Day-ahead demand at node i, during hour h (MW)
$D_{ih}^{\psi_2}$	Intraday market 2 demand adjustment at node i, during hour h (MW)
D_{ih}^{ω}	Real-time demand adjustment at node i, during hour h (MW)
$\overline{K}_{ij}$	Maximum capacity at node i, for generator j (MW)
$\underline{\mathrm{K}}_{ij}$	Minimum power output at node i, for generator j (MW)
MC_{ij}	Marginal cost of production at node i, for generator j (\$/MWh)
NL_{ij}	No-load cost at node i, for generator j (\$)
$PTDF_{il}$	Power transfer distribution factor of net injection at node i, on line l
RU_{ij}	Ramp-up limit at node i, for generator j (MW)
RD_{ij}	Ramp-down limit at node i, for generator j (MW)
S_h^{ϕ}	Day-ahead spinning reserve requirement during hour h (MW)
$S_h^{\psi_2}$	Intraday market 2 spinning reserve requirement during hour h (MW)
S_h^{ω}	Real-time spinning reserve requirement during hour h (MW)

SD_{ij}	Shut-down cost at node i, for generator j (\$)
SPF_{ij}	Maximum fraction of capacity that can provide spinning reserves at node i, for generator j
SU_{ij}	Start-up cost at node i, for generator j (\$)
T_l	Transmission capacity limit on line l (MW)
TU_{ij}	Minimum uptime at node i, for generator j (hr)
TD_{ij}	Minimum downtime at node i, for generator j (hr)
W_{ijh}^{ϕ}	Day-ahead wind production forecast at node i, for generator j, during hour h (MW)
$W_{ijh}^{\psi_2}$	Intraday market 2 wind production forecast at node i, for generator j, during hour h (MW)
W_{ijh}^{ω}	Real-time wind production forecast at node i, for generator j, during hour h (MW)
WCC	Wind curtailment cost - set to \$100/MWh

Primal Variables

s_{ijh}^{ϕ}	Day-ahead spinning reserves at node i, for generator j, during hour h (MW)
$s_{ijh}^{\psi_2}$	Intraday market 2 spinning reserves at node i, for generator j, during hour h (MW)
s_{ijh}^{ω}	Real-time spinning reserves at node i, for generator j, during hour h (MW)
u_{ijh}^{ϕ}	Day-ahead commitment status at node i, for generator j, during hour h
$u_{ijh}^{\psi_2}$	Intraday market 2 commitment status at node i, for generator j, during hour h
u_{ijh}^{ω}	Real-time commitment status at node i, for generator j, during hour h
v_{ijh}^{ϕ}	Day-ahead start-up status at node i, for generator j, during hour h
$v_{ijh}^{\psi_2}$	Intraday market 2 start-up status at node i, for generator j, during hour h
v_{ijh}^{ω}	Real-time start-up status at node i, for generator j, during hour h
w_{ijh}^{ϕ}	Day-ahead shut-down status at node i, for generator j, during hour h
$w_{ijh}^{\psi_2}$	Intraday market 2 shut-down status at node i, for generator j, during hour h
w_{ijh}^{ω}	Real-time shut-down status at node i, for generator j, during hour h
wc_{ijh}^{ω}	Wind curtailment at node i, for generator j, during hour h (MWh)
x_{ijh}^{ϕ}	Day-ahead generation at node i, for generator j, during hour h (MWh)
$x_{ijh}^{\psi_2}$	Intraday market 2 generation at node i, for generator j, during hour h (MWh)
x_{ijh}^{ω}	Real-time generation at node i, for generator j, during hour h (MWh)
y_{ih}^{ϕ}	Day-ahead net injection into node i, during hour h (MWh)
$y_{ih}^{\psi_2}$	Intraday market 2 net injection into node i, during hour h (MWh)
y_{ih}^{ω}	Real-time net injection into node i, during hour h (MWh)

Dual Variables

pe_{ih}^{ϕ}	Day-ahead energy price at node i, during hour h (\$/MWh)
$pe_{ih}^{\psi_2}$	Intraday market 2 energy price at node i, during hour h (\$/MWh)
pe_{ih}^{ω}	Real-time energy price at node i, during hour h (\$/MWh)

ps^{ϕ}_{ih}	Day-ahead spinning reserve price at node i, during hour h (\$/MW)
$ps^{\psi_2}_{ih}$	Intraday market 2 spinning reserve price at node i, during hour h (\$/MW)
ps^{ω}_{ih}	Real-time spinning reserve price at node i, during hour h (\$/MW)

D.2 Two-Settlement Model Formulation

Day-Ahead Market

The model formulation for the day-ahead market is provided below. The objective function (D.1) of the model minimizes the total cost of the system. Total cost is comprised of 4 parts: (1) variable costs, which are incurred when a generator has positive production, (2) start-up costs, which are incurred when a generator is turned on, (3) no-load costs, which are incurred whenever a generator is committed, and (4) shut-down costs, which are incurred when a generator is turned off.

Non-wind generators are constrained by maximum and minimum capacity constraints (D.2 - D.3), ramp up and ramp down constraints (D.4 - D.5), a spinning reserve allocation constraint (D.6), and minimum uptime and downtime constraints (D.8 - D.9). Additionally, day-ahead start-up and shut-down variables are calculated for non-wind generators in equation (D.7). If a generator is scheduled to be off in time period *h-1* (i.e., $u^{\phi}_{ijh-1} = 0$), but on in time period h (i.e., $u^{\phi}_{ijh} = 1$), then the start-up variable must equal 1 (i.e., $v^{\phi}_{ijh} = 1$). However, if the generator is scheduled to be on in time period *h-1* (i.e., $u^{\phi}_{ijh-1} = 1$), but off in time period h (i.e., $u^{\phi}_{ijh} = 0$), then the shutdown variable must equal 1 (i.e., $w^{\phi}_{ijh} = 1$). Next, wind generators are constrained by the wind production forecast equation (D.10), which prevents them from being scheduled to produce more than their maximum day-ahead forecast level. Further, network constraints are included in equations (D.11 - D.13), while the market-clearing energy and market-clearing spinning reserve constraints are included in equations (D.14) and (D.15) respectively. Finally, non-negativity and binary declarations are provided in equations (D.16 - D.18).

$$\min \quad \sum_h \Big[\sum_i \sum_j MC_{ij} \cdot x^{\phi}_{ijh} + \sum_i \sum_{j \in J^{nw}_i} (SU_{ij} \cdot v^{\phi}_{ijh} + NL_{ij} \cdot u^{\phi}_{ijh} + SD_{ij} \cdot w^{\phi}_{ijh}) \Big] \tag{D.1}$$

$$\text{subject to} \quad x^{\phi}_{ijh} + s^{\phi}_{ijh} \leq \overline{K}_{ij} \cdot u^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{D.2}$$

$$x^{\phi}_{ijh} \geq \underline{K}_{ij} \cdot u^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{D.3}$$

$$x^{\phi}_{ijh} - x^{\phi}_{ijh-1} + s^{\phi}_{ijh} \leq RU_{ij} \cdot u^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{D.4}$$

$$x^{\phi}_{ijh} - x^{\phi}_{ijh-1} \geq -RD_{ij} \cdot u^{\phi}_{ijh-1} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{D.5}$$

$$s^{\phi}_{ijh} \leq (\overline{K}_{ij} \cdot u^{\phi}_{ijh}) \cdot SPF_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{D.6}$$

$$u^{\phi}_{ijh} - u^{\phi}_{ijh-1} = v^{\phi}_{ijh} - w^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{D.7}$$

$$\sum_{q=h-TU_{ij}+1}^{h} v_{ijq}^{\phi} \le u_{ijh}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{nw}, \forall h \in [TU_{ij}, H] \tag{D.8}$$

$$\sum_{q=h-TD_{ij}+1}^{h} w_{ijq}^{\phi} \le 1 - u_{ijh}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{nw}, \forall h \in [TD_{ij}, H] \tag{D.9}$$

$$x_{ijh}^{\phi} \le W_{ijh}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{w}, \forall h \in H \tag{D.10}$$

$$\sum_i y_{ih}^{\phi} = 0 \qquad \forall h \in H \tag{D.11}$$

$$-\sum_i PTDF_{il} \cdot y_{ih}^{\phi} \le T_l \qquad \forall l \in L, \forall h \in H \tag{D.12}$$

$$-\sum_i PTDF_{il} \cdot y_{ih}^{\phi} \ge -T_l \qquad \forall l \in L, \forall h \in H \tag{D.13}$$

$$\sum_{j \in J_i} x_{ijh}^{\phi} + y_{ih}^{\phi} = D_{ih}^{\phi} \qquad \left(pe_{ih}^{\phi}\right) \qquad \forall i \in I, \forall h \in H \tag{D.14}$$

$$\sum_i \sum_{j \in J_i^{nw}} s_{ijh}^{\phi} = S_h^{\phi} \qquad \left(ps_h^{\phi}\right) \qquad \forall h \in H \tag{D.15}$$

$$x_{ijh}^{\phi} \ge 0 \qquad \forall i \in I, \forall j \in J_i, \forall h \in H \tag{D.16}$$

$$s_{ijh}^{\phi} \ge 0 \qquad \forall i \in I, \forall j \in J_i^{nw}, \forall h \in H \tag{D.17}$$

$$u_{ijh}^{\phi}, v_{ijh}^{\phi}, w_{ijh}^{\phi} \in \{0,1\} \qquad \forall i \in I, \forall j \in J_i^{nw}, \forall h \in H \tag{D.18}$$

Real-Time Market

The model formulation for the real-time market is provided below. Note that real-time variables represent adjustments from the day-ahead stage, where the sum of the day-ahead and real-time values equal the total level for each variable. The objective function (D.19) of this model minimizes the total cost of the system. In this case, variable costs, start-up costs, no-load costs, and shut-down costs are minimized for the real-time stage only.

The constraints in this problem are included separately for fast-start generators (i.e., NGCT, oil, and hydro plants), slow-start generators (i.e., NGCC, coal, and nuclear plants), and wind generators. Fast-start generators are constrained by maximum and minimum capacity constraints (D.20, D.22), ramp up and ramp down constraints (D.24, D.26), a spinning reserve allocation constraint (D.28), and minimum uptime and downtime constraints (D.31 - D.32). Additionally, real-time start-up and shut-down variables are calculated for fast-start generators in equation (D.30). The logic for these constraints is the same as in the day-ahead stage but includes both the day-ahead parameters and real-time decision variables. Further, these fast-start generators are able to update their commitment status in the real-time.

Slow-start generators are also constrained by maximum and minimum capacity constraints (D.21, D.23), ramp up and ramp down constraints (D.25, D.27), and a spinning reserve allocation constraint (D.29). In this case, these plants are unable to update their commitment status during the real-time stage. Next, wind generators are constrained by the wind production forecast equation (D.33), network constraints are included in equations (D.34 - D.36), and the market-clearing energy and market-clearing spinning reserve constraints are included in equations (D.37) and (D.38) respectively. Lastly, non-negativity and binary constraints are provided by equations (D.39 - D.45).

$$\min \quad \sum_h \Big[\sum_i \sum_j MC_{ij} \cdot x^{\omega}_{ijh} + \sum_i \sum_{j \in J^f_i} (SU_{ij} \cdot v^{\omega}_{ijh} + NL_{ij} \cdot u^{\omega}_{ijh} + SD_{ij} \cdot w^{\omega}_{ijh}) + \sum_i \sum_{j \in J^w_i} WCC \cdot wc^{\omega}_{ijh} \Big] \tag{D.19}$$

subject to

$$\left(x^{\phi}_{ijh} + x^{\omega}_{ijh}\right) + \left(s^{\phi}_{ijh} + s^{\omega}_{ijh}\right) \le \overline{K}_{ij} \cdot (u^{\phi}_{ijh} + u^{\omega}_{ijh}) \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in H \tag{D.20}$$

$$\left(x^{\phi}_{ijh} + x^{\omega}_{ijh}\right) + \left(s^{\phi}_{ijh} + s^{\omega}_{ijh}\right) \le \overline{K}_{ij} \cdot u^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^s_i, \forall h \in H \tag{D.21}$$

$$x^{\phi}_{ijh} + x^{\omega}_{ijh} \ge \underline{\mathrm{K}}_{ij} \cdot (u^{\phi}_{ijh} + u^{\omega}_{ijh}) \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in H \tag{D.22}$$

$$x^{\phi}_{ijh} + x^{\omega}_{ijh} \ge \underline{\mathrm{K}}_{ij} \cdot u^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^s_i, \forall h \in H \tag{D.23}$$

$$(x^{\phi}_{ijh} + x^{\omega}_{ijh}) - (x^{\phi}_{ijh-1} + x^{\omega}_{ijh-1}) + \left(s^{\phi}_{ijh} + s^{\omega}_{ijh}\right) \le RU_{ij} \cdot (u^{\phi}_{ijh} + u^{\omega}_{ijh}) \quad \forall i \in I, \forall j \in J^f_i, \forall h \in H \tag{D.24}$$

$$(x^{\phi}_{ijh} + x^{\omega}_{ijh}) - (x^{\phi}_{ijh-1} + x^{\omega}_{ijh-1}) + \left(s^{\phi}_{ijh} + s^{\omega}_{ijh}\right) \le RU_{ij} \cdot u^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^s_i, \forall h \in H \tag{D.25}$$

$$(x^{\phi}_{ijh} + x^{\omega}_{ijh}) - (x^{\phi}_{ijh-1} + x^{\omega}_{ijh-1}) \ge -RD_{ij} \cdot (u^{\phi}_{ijh-1} + u^{\omega}_{ijh-1}) \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in H \tag{D.26}$$

$$(x^{\phi}_{ijh} + x^{\omega}_{ijh}) - (x^{\phi}_{ijh-1} + x^{\omega}_{ijh-1}) \ge -RD_{ij} \cdot u^{\phi}_{ijh-1} \qquad \forall i \in I, \forall j \in J^s_i, \forall h \in H \tag{D.27}$$

$$s^{\phi}_{ijh} + s^{\omega}_{ijh} \le \overline{K}_{ij} \cdot (u^{\phi}_{ijh} + u^{\omega}_{ijh}) \cdot SPF_{ij} \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in H \tag{D.28}$$

$$s^{\phi}_{ijh} + s^{\omega}_{ijh} \le \overline{K}_{ij} \cdot (u^{\phi}_{ijh}) \cdot SPF_{ij} \qquad \forall i \in I, \forall j \in J^s_i, \forall h \in H \tag{D.29}$$

$$(u^{\phi}_{ijh} + u^{\omega}_{ijh}) - (u^{\phi}_{ijh-1} + u^{\omega}_{ijh-1}) = (v^{\phi}_{ijh} + v^{\omega}_{ijh}) - (w^{\phi}_{ijh} + w^{\omega}_{ijh}) \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in H \tag{D.30}$$

$$\sum_{q=h-TU_{ij}+1}^{h} (v^{\phi}_{ijq} + v^{\omega}_{ijq}) \le (u^{\phi}_{ijh} + u^{\omega}_{ijh}) \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in [TU_{ij}, H] \tag{D.31}$$

$$\sum_{q=h-TD_{ij}+1}^{h} (w^{\phi}_{ijq} + w^{\omega}_{ijq}) \le 1 - (u^{\phi}_{ijh} + u^{\omega}_{ijh}) \qquad \forall i \in I, \forall j \in J^f_i, \forall h \in [TD_{ij}, H] \tag{D.32}$$

$$(x^{\phi}_{ijh} + x^{\omega}_{ijh}) + wc^{\omega}_{ijh} = W^{\omega}_{ijh} \qquad \forall i \in I, \forall j \in J^w_i, \forall h \in H \tag{D.33}$$

$$\sum_i y^{\omega}_{ih} = 0 \qquad \forall h \in H \tag{D.34}$$

$$-\sum_i PTDF_{il} \cdot \left(y^{\phi}_{ih} + y^{\omega}_{ih}\right) \le T_l \qquad \forall l \in L, \forall h \in H \tag{D.35}$$

$$-\sum_i PTDF_{il} \cdot \left(y^{\phi}_{ih} + y^{\omega}_{ih}\right) \ge -T_l \qquad \forall l \in L, \forall h \in H \tag{D.36}$$

$$\sum_{j \in J_i} x^{\omega}_{ijh} + y^{\omega}_{ih} = D^{\omega}_{ih} \qquad \left(pe^{\omega}_h\right) \qquad \forall i \in I, \forall h \in H \tag{D.37}$$

$$\sum_{i} \sum_{j \in J_i^{nw}} s_{ijh}^{\omega} = S_h^{\omega} \qquad \left(ps_h^{\omega}\right) \qquad \forall h \in H \tag{D.38}$$

$$x_{ijh}^{\phi} + x_{ijh}^{\omega} \geq 0 \qquad \forall i \in I, \forall j \in J_i, \forall h \in H \tag{D.39}$$

$$s_{ijh}^{\phi} + s_{ijh}^{\omega} \geq 0 \qquad \forall i \in I, \forall j \in J_i^{nw}, \forall h \in H \tag{D.40}$$

$$wc_{ijh}^{\omega} \geq 0 \qquad \forall i \in I, \forall j \in J_i^{w}, \forall h \in H \tag{D.41}$$

$$u_{ijh}^{\omega} \in \{0,1\} \qquad \forall i \in I, \forall j \in J_i^{f}, \forall h \in H \tag{D.42}$$

$$u_{ijh}^{\phi} + u_{ijh}^{\omega} \leq 1 \qquad \forall i \in I, \forall j \in J_i^{f}, \forall h \in H \tag{D.43}$$

$$0 \leq v_{ijh}^{\phi} + v_{ijh}^{\omega} \leq 1 \qquad \forall i \in I, \forall j \in J_i^{f}, \forall h \in H \tag{D.44}$$

$$0 \leq w_{ijh}^{\phi} + w_{ijh}^{\omega} \leq 1 \qquad \forall i \in I, \forall j \in J_i^{f}, \forall h \in H \tag{D.45}$$

D.3 Multi-Settlement Model Formulation

Intraday Market 2: 1am EST (d)

An example of the model formulation for one intraday market stage (i.e., Intraday Market 2) is provided below. This stage is cleared for a subset of hours during the operating day, represented by H^{ψ_2} (i.e., hours 5 - 23). The timeline for this market clearing can be seen in Figure 2 of the paper. Additionally, the intraday variables represent adjustments from the previous stages, similar to the real-time market in the two-settlement model (D.105 - D.110).

In the Intraday Market 2 stage, the problem is formulated separately for five groups of generators, including coal plants, NGCC plants, nuclear plants, fast-start (i.e., NGCT, hydro, and oil) plants, and wind plants. Each group of generators solve their problem for different subsets of hours, depending on the notification times of the plant type. For example, coal plants are slow-starting technology types that have long notification times as defined in [23]. Therefore, they are unable to update their commitment status during hours 5 - 7 of the operating day, but are able to adjust their commitment status for hours 8 - 23 of the operating day. Other generator types, such as NGCT, hydro, and oil plants, are fast-starting technologies and are able to update their commitment statuses for all hours of the operating day. The set of hours where each generator type can change their commitment status is shown in Figure 3 of the paper.

Similar to the two-settlement model, the objective function for the Intraday Market 2 stage (D.46) minimizes the total cost of the system. In this case, the start-up, no-load, and shut-down cost calculation is separated for different hours of the operating day and different generation types. However, the variable costs are calculated for all generation types and all hours of the operating day. Further, the constraints for each group of generators are formulated in a similar way to the real-time market stage of the two-settlement model. Each type of generator acts as a fast-start or slow-start technology depending on their notification time and the hour the market is clearing. For example, coal plants act as slow-start technologies during hours 5 - 7 of the operating day (D.47 - D.51), but act as fast-start technologies during hours 8 - 23 of the operating day (D.52 - D.63). Other technology types are formulated in a similar manner. Network and market clearing constraints are included for all hours of the operating day that are cleared by the Intraday Market 2 stage (D.99 - D.103). Lastly, non-negativity of reserve provision for thermal power plants is given by equation (D.104).

$$\begin{aligned}\min \quad & \sum_{h\in H^{\psi_2}}\sum_i\sum_j MC_{ij}\cdot x^{\psi_2}_{ijh} + \sum_{h\in[8,23]}\sum_i\sum_{j\in J_i^c}(SU_{ij}\cdot v^{\psi_2}_{ijh} + NL_{ij}\cdot u^{\psi_2}_{ijh} + SD_{ij}\cdot w^{\psi_2}_{ijh}) \\ & + \sum_{h\in[6,23]}\sum_i\sum_{j\in J_i^{cc}}(SU_{ij}\cdot v^{\psi_2}_{ijh} + NL_{ij}\cdot u^{\psi_2}_{ijh} + SD_{ij}\cdot w^{\psi_2}_{ijh}) \\ & + \sum_{h\in H^{\psi_2}}\sum_i\sum_{j\in J_i^f}(SU_{ij}\cdot v^{\psi_2}_{ijh} + NL_{ij}\cdot u^{\psi_2}_{ijh} + SD_{ij}\cdot w^{\psi_2}_{ijh}) \end{aligned} \tag{D.46}$$

subject to <u>Coal Plants: Hours 5 - 7</u>

$$\left(x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh}\right) + \left(s^{\phi\to\psi_1}_{ijh} + s^{\psi_2}_{ijh}\right) \le \overline{K}_{ij}\cdot u^{\phi\to\psi_1}_{ijh} \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[5,7] \tag{D.47}$$

$$x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh} \ge \underline{K}_{ij}\cdot u^{\phi\to\psi_1}_{ijh} \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[5,7] \tag{D.48}$$

$$\begin{aligned}&(x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh}) - (x^{\phi\to\psi_1}_{ijh-1} + x^{\psi_2}_{ijh-1}) + \left(s^{\phi\to\psi_1}_{ijh} + s^{\psi_2}_{ijh}\right) \le RU_{ij}\cdot u^{\phi\to\psi_1}_{ijh} \\ &\qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[5,7]\end{aligned} \tag{D.49}$$

$$(x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh}) - (x^{\phi\to\psi_1}_{ijh-1} + x^{\psi_2}_{ijh-1}) \ge -RD_{ij}\cdot u^{\phi\to\psi_1}_{ijh-1} \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[5,7] \tag{D.50}$$

$$s^{\phi\to\psi_1}_{ijh} + s^{\psi_2}_{ijh} \le \overline{K}_{ij}\cdot(u^{\phi\to\psi_1}_{ijh})\cdot SPF_{ij} \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[5,7] \tag{D.51}$$

<u>Coal Plants: Hours 8 - 23</u>

$$\left(x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh}\right) + \left(s^{\phi\to\psi_1}_{ijh} + s^{\psi_2}_{ijh}\right) \le \overline{K}_{ij}\cdot(u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh}) \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23] \tag{D.52}$$

$$x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh} \ge \underline{K}_{ij}\cdot(u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh}) \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23] \tag{D.53}$$

$$\begin{aligned}&(x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh}) - (x^{\phi\to\psi_1}_{ijh-1} + x^{\psi_2}_{ijh-1}) + \left(s^{\phi\to\psi_1}_{ijh} + s^{\psi_2}_{ijh}\right) \le RU_{ij}\cdot(u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh}) \\ &\qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23]\end{aligned} \tag{D.54}$$

$$\begin{aligned}&(x^{\phi\to\psi_1}_{ijh} + x^{\psi_2}_{ijh}) - (x^{\phi\to\psi_1}_{ijh-1} + x^{\psi_2}_{ijh-1}) \ge -RD_{ij}\cdot(u^{\phi\to\psi_1}_{ijh-1} + u^{\psi_2}_{ijh-1}) \\ &\qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23]\end{aligned} \tag{D.55}$$

$$s^{\phi\to\psi_1}_{ijh} + s^{\psi_2}_{ijh} \le \overline{K}_{ij}\cdot(u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh})\cdot SPF_{ij} \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23] \tag{D.56}$$

$$\begin{aligned}&(u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh}) - (u^{\phi\to\psi_1}_{ijh-1} + u^{\psi_2}_{ijh-1}) = (v^{\phi\to\psi_1}_{ijh} + v^{\psi_2}_{ijh}) - (w^{\phi\to\psi_1}_{ijh} + w^{\psi_2}_{ijh}) \\ &\qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23]\end{aligned} \tag{D.57}$$

$$\sum_{q=h-TU_{ij}+1}^{h}(v^{\phi\to\psi_1}_{ijq} + v^{\psi_2}_{ijh}) \le (u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh}) \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[TU_{ij}, H] \tag{D.58}$$

$$\sum_{q=h-TD_{ij}+1}^{h}(w^{\phi\to\psi_1}_{ijq} + w^{\psi_2}_{ijh}) \le 1 - (u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh}) \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[TD_{ij}, H] \tag{D.59}$$

$$u^{\psi_2}_{ijh} \in \{0,1\} \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23] \tag{D.60}$$

$$u^{\phi\to\psi_1}_{ijh} + u^{\psi_2}_{ijh} \le 1 \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23] \tag{D.61}$$

$$0 \le w^{\phi\to\psi_1}_{ijh} + w^{\psi_2}_{ijh} \le 1 \qquad \forall i\in I, \forall j\in J_i^c, \forall h\in[8,23] \tag{D.62}$$

$$0 \le v_{ijh}^{\phi\to\psi_1} + v_{ijh}^{\psi_2} \le 1 \qquad \forall i \in I, \forall j \in J_i^c, \forall h \in [8,23] \tag{D.63}$$

<u>NGCC Plants: Hour 5</u>

$$\left(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}\right) + \left(s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2}\right) \le \overline{K}_{ij} \cdot u_{ijh}^{\phi\to\psi_1} \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [5] \tag{D.64}$$

$$x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2} \ge \underline{K}_{ij} \cdot u_{ijh}^{\phi\to\psi_1} \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [5] \tag{D.65}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) + \left(s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2}\right) \le RU_{ij} \cdot u_{ijh}^{\phi\to\psi_1}$$
$$\forall i \in I, \forall j \in J_i^{cc}, \forall h \in [5] \tag{D.66}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) \ge -RD_{ij} \cdot u_{ijh-1}^{\phi\to\psi_1} \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [5] \tag{D.67}$$

$$s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2} \le \overline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1}) \cdot SPF_{ij} \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [5] \tag{D.68}$$

<u>NGCC Plants: Hours 6 - 23</u>

$$\left(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}\right) + \left(s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2}\right) \le \overline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.69}$$

$$x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2} \ge \underline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.70}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) + \left(s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2}\right) \le RU_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2})$$
$$\forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.71}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) \ge -RD_{ij} \cdot (u_{ijh-1}^{\phi\to\psi_1} + u_{ijh-1}^{\psi_2})$$
$$\forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.72}$$

$$s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2} \le \overline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \cdot SPF_{ij} \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.73}$$

$$(u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) - (u_{ijh-1}^{\phi\to\psi_1} + u_{ijh-1}^{\psi_2}) = (v_{ijh}^{\phi\to\psi_1} + v_{ijh}^{\psi_2}) - (w_{ijh}^{\phi\to\psi_1} + w_{ijh}^{\psi_2})$$
$$\forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.74}$$

$$\sum_{q=h-TU_{ij}+1}^{h} (v_{ijq}^{\phi\to\psi_1} + v_{ijh}^{\psi_2}) \le (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [TU_{ij}, H] \tag{D.75}$$

$$\sum_{q=h-TD_{ij}+1}^{h} (w_{ijq}^{\phi\to\psi_1} + w_{ijh}^{\psi_2}) \le 1 - (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [TD_{ij}, H] \tag{D.76}$$

$$u_{ijh}^{\psi_2} \in \{0,1\} \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.77}$$

$$u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2} \le 1 \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.78}$$

$$0 \le w_{ijh}^{\phi\to\psi_1} + w_{ijh}^{\psi_2} \le 1 \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.79}$$

$$0 \le v_{ijh}^{\phi\to\psi_1} + v_{ijh}^{\psi_2} \le 1 \qquad \forall i \in I, \forall j \in J_i^{cc}, \forall h \in [6,23] \tag{D.80}$$

<u>Nuclear Plants: Hours 5 - 23</u>

$$\left(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}\right) \le \overline{K}_{ij} \cdot u_{ijh}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{n}, \forall h \in H^{\psi_2} \tag{D.81}$$

$$x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2} \ge \underline{K}_{ij} \cdot u_{ijh}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{n}, \forall h \in H^{\psi_2} \tag{D.82}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) \le RU_{ij} \cdot u_{ijh}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{n}, \forall h \in H^{\psi_2} \tag{D.83}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) \ge -RD_{ij} \cdot u_{ijh-1}^{\phi} \qquad \forall i \in I, \forall j \in J_i^{n}, \forall h \in H^{\psi_2} \tag{D.84}$$

NGCT, Hydro, and Oil Plants: Hours 5 - 23

$$\left(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}\right) + \left(s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2}\right) \leq \overline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.85}$$

$$x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2} \geq \underline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.86}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) + \left(s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2}\right) \leq RU_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2})$$
$$\forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.87}$$

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) - (x_{ijh-1}^{\phi\to\psi_1} + x_{ijh-1}^{\psi_2}) \geq -RD_{ij} \cdot (u_{ijh-1}^{\phi\to\psi_1} + u_{ijh-1}^{\psi_2})$$
$$\forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.88}$$

$$s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2} \leq \overline{K}_{ij} \cdot (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \cdot SPF_{ij} \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.89}$$

$$(u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) - (u_{ijh-1}^{\phi\to\psi_1} + u_{ijh-1}^{\psi_2}) = (v_{ijh}^{\phi\to\psi_1} + v_{ijh}^{\psi_2}) - (w_{ijh}^{\phi\to\psi_1} + w_{ijh}^{\psi_2})$$
$$\forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.90}$$

$$\sum_{q=h-TU_{ij}+1}^{h} (v_{ijq}^{\phi\to\psi_1} + v_{ijh}^{\psi_2}) \leq (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in [TU_{ij}, H] \tag{D.91}$$

$$\sum_{q=h-TD_{ij}+1}^{h} (w_{ijq}^{\phi\to\psi_1} + w_{ijh}^{\psi_2}) \leq 1 - (u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2}) \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in [TD_{ij}, H] \tag{D.92}$$

$$u_{ijh}^{\psi_2} \in \{0,1\} \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.93}$$

$$u_{ijh}^{\phi\to\psi_1} + u_{ijh}^{\psi_2} \leq 1 \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.94}$$

$$0 \leq w_{ijh}^{\phi\to\psi_1} + w_{ijh}^{\psi_2} \leq 1 \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.95}$$

$$0 \leq v_{ijh}^{\phi\to\psi_1} + v_{ijh}^{\psi_2} \leq 1 \qquad \forall i \in I, \forall j \in J_i^f, \forall h \in H^{\psi_2} \tag{D.96}$$

Wind Plants: Hours 5 - 23

$$(x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2}) \leq W_{ijh}^{\psi_2} \qquad \forall i \in I, \forall j \in J_i^w, \forall h \in H^{\psi_2} \tag{D.97}$$

All Plants: Hours 5 - 23

$$x_{ijh}^{\phi\to\psi_1} + x_{ijh}^{\psi_2} \geq 0 \qquad \forall i \in I, \forall j \in J_i, \forall h \in H^{\psi_2} \tag{D.98}$$

Network and Clearing Constraints: Hours 5 - 23

$$\sum_i y_{ih}^{\psi_2} = 0 \qquad \forall h \in H^{\psi_2} \tag{D.99}$$

$$-\sum_i PTDF_{il} \cdot \left(y_{ih}^{\phi\to\psi_1} + y_{ih}^{\psi_2}\right) \leq T_l \qquad \forall l \in L, \forall h \in H^{\psi_2} \tag{D.100}$$

$$-\sum_i PTDF_{il} \cdot \left(y_{ih}^{\phi\to\psi_1} + y_{ih}^{\psi_2}\right) \geq -T_l \qquad \forall l \in L, \forall h \in H^{\psi_2} \tag{D.101}$$

$$\sum_{j\in J_i} x_{ijh}^{\psi_2} + y_{ih}^{\psi_2} = D_{ih}^{\psi_2} \qquad \left(pe_h^{\psi_2}\right) \qquad \forall i \in I, \forall h \in H^{\psi_2} \tag{D.102}$$

$$\sum_i \sum_{j\in J_i^{nw}} s_{ijh}^{\psi_2} = S_h^{\psi_2} \qquad \left(ps_h^{\psi_2}\right) \qquad \forall h \in H^{\psi_2} \tag{D.103}$$

Non-Wind Plants: Hours 5 - 23

$$s_{ijh}^{\phi\to\psi_1} + s_{ijh}^{\psi_2} \geq 0 \qquad \forall i \in I, \forall j \in J_i^{nw}, \forall h \in H^{\psi_2} \tag{D.104}$$

All Plants: Hours 5 - 23

$$x_{ijh}^{\phi\to\psi_1} = x_{ijh}^{\phi} + x_{ijh}^{\psi_1} \qquad \forall i \in I, \forall j \in J_i, \forall h \in H^{\psi_2} \tag{D.105}$$

$$s_{ijh}^{\phi\to\psi_1} = s_{ijh}^{\phi} + s_{ijh}^{\psi_1} \qquad \forall i \in I, \forall j \in J_i, \forall h \in H^{\psi_2} \tag{D.106}$$

$$y_{ih}^{\phi\to\psi_1} = y_{ih}^{\phi} + y_{ih}^{\psi_1} \qquad \forall i \in I, \forall h \in H^{\psi_2} \tag{D.107}$$

$$u_{ijh}^{\phi\to\psi_1} = u_{ijh}^{\phi} + u_{ijh}^{\psi_1} \qquad \forall i \in I, \forall j \in J_i, \forall h \in H^{\psi_2} \tag{D.108}$$

$$v_{ijh}^{\phi\to\psi_1} = v_{ijh}^{\phi} + v_{ijh}^{\psi_1} \qquad \forall i \in I, \forall j \in J_i, \forall h \in H^{\psi_2} \tag{D.109}$$

$$w_{ijh}^{\phi\to\psi_1} = w_{ijh}^{\phi} + w_{ijh}^{\psi_1} \qquad \forall i \in I, \forall j \in J_i, \forall h \in H^{\psi_2} \tag{D.110}$$

Appendix E: Uplift Calculation Method

In U.S. electricity markets, when an auction is cleared, the economic dispatch does not always provide sufficient revenue for generators to cover their total variable and fixed costs. This is because energy prices from security constrained economic dispatch models equal the short run marginal cost of production by location, and do not reflect the unit commitment costs (e.g. no-load, start-up, shut-down costs) incurred by the generators, which may result in the inability to recover fixed costs. Additionally, due to intertemporal constraints, some generators may be online even when the price of electricity is lower than their price bid. For instance, if a generator is scheduled to be dispatched by its RTO for a few hours of the operating day, minimum uptime constraints could prevent the generator from turning off if it is no longer needed, even during hours in which the electricity price is lower than the unit's marginal cost. For these reasons, out-of-market uplift payments may be needed for generation resources that are committed and dispatched by the RTO, but are unable to recover their total costs through market clearing prices. These uplift payments represent the shortfall between market revenues and total costs that are eligible for compensation. Following the method that is currently in use in U.S. electricity markets, we calculate uplift for each market stage separately. Thus, shortfalls between costs and revenues are calculated at each market stage, and the same cost cannot be compensated twice. Additional details are provided below.

Revenue

In the two-settlement market design, ER^{ϕ}_{ijh} and ER^{ω}_{ijh} are defined as the total day-ahead and real-time energy market revenue received by each non-wind generator during every hour, while RR^{ϕ}_{ijh} and RR^{ω}_{ijh} are defined as the total day-ahead and real-time reserve market revenue received by each generator during every hour. Real-time energy and reserve revenue are considered adjustments from the day-ahead revenues, and are calculated using the real-time energy and reserve adjustment variables. The formulas used to calculate the day-ahead and real-time revenues are presented below:

$$ER^{\phi}_{ijh} = x^{\phi}_{ijh} \cdot pe^{\phi}_{ih} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.1}$$

$$ER^{\omega}_{ijh} = x^{\omega}_{ijh} \cdot pe^{\omega}_{ih} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.2}$$

$$RR^{\phi}_{ijh} = s^{\phi}_{ijh} \cdot ps^{\phi}_{ih} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.3}$$

$$RR^{\omega}_{ijh} = s^{\omega}_{ijh} \cdot ps^{\omega}_{ih} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.4}$$

The multi-settlement energy and reserve market revenues are calculated in a similar fashion. The index $s \in S$ is defined for all intraday and real-time market stages, excluding the day-ahead. We assume these day-ahead revenues are calculated the same in the multi-settlement and two-settlement structures. However, in the multi-settlement structure, the set S is used represent the intraday and real-time revenues, which are considered adjustments from the previous market stages. The general equations for the energy and reserve market revenues in these stages are listed below:

$$ER^s_{ijh} = x^s_{ijh} \cdot pe^s_{ih} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H, \forall s \in S \tag{E.5}$$

$$RR^s_{ijh} = s^s_{ijh} \cdot ps^s_{ih} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H, \forall s \in S \tag{E.6}$$

Variable Cost and No-load Cost

VC^{ϕ}_{ijh} and VC^{ω}_{ijh} are the day-ahead and real-time variable cost of each non-wind generator during hour h, while NLC^{ϕ}_{ijh} and NLC^{ω}_{ijh} represent the day-ahead and real-time no-load cost of the generator. Variable costs are incurred based on the level of output produced by each generator. No-load costs are fixed costs that are incurred if a unit is committed and producing, regardless of its output level. In the two-settlement structure, the day-ahead and real-time variable and no-load cost calculations are shown below:

$$VC^{\phi}_{ijh} = x^{\phi}_{ijh} \cdot MC_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.7}$$

$$VC^{\omega}_{ijh} = x^{\omega}_{ijh} \cdot MC_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.8}$$

$$NLC^{\phi}_{ijh} = u^{\phi}_{ijh} \cdot NL_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.9}$$

$$NLC^{\omega}_{ijh} = u^{\omega}_{ijh} \cdot NL_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.10}$$

The general formulation for the multi-settlement variable and no-load costs for the intraday and real-time stages are:

$$VC^s_{ijh} = x^s_{ijh} \cdot MC_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H, \forall s \in S \tag{E.11}$$

$$NLC^s_{ijh} = u^s_{ijh} \cdot NL_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H, \forall s \in S \tag{E.12}$$

Start-Up and Shut-Down Cost

SUC^{ϕ}_{ijh}, SUC^{ω}_{ijh}, SDC^{ϕ}_{ijh}, and SDC^{ω}_{ijh} are defined as the day-ahead and real-time start-up and shut-down cost of each non-wind generator during every hour. Start-up costs are fixed costs that are incurred during the hour a generator turns on, while shut-down costs are fixed costs that are incurred during the hour a generator turns off. The real-time start-up and shut-down costs are adjustments from the day-ahead costs and can be negative. However, this does not mean that units are allowed to decommit in the real-time. For example, a negative start-up cost in the real-time represents a situation where a unit is scheduled to turn on for a certain hour day ahead (and is scheduled to incur a positive start-up cost), but does not actually turn on for that hour in real time. This could occur if the unit is chosen to start up during an earlier hour of the day in the real-time stage. Since no start-up cost is actually incurred for the original hour scheduled in the day-ahead, the positive day-ahead start-up cost is offset by a negative real-time start-up cost. The equations used to calculate the day-ahead and real-time start-up and shut-down costs are presented below:

$$SUC^{\phi}_{ijh} = v^{\phi}_{ijh} \cdot SU_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.13}$$

$$SUC^{\omega}_{ijh} = v^{\omega}_{ijh} \cdot SU_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.14}$$

$$SDC^{\phi}_{ijh} = w^{\phi}_{ijh} \cdot SD_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.15}$$

$$SDC^{\omega}_{ijh} = w^{\omega}_{ijh} \cdot SD_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.16}$$

Extending this formulation from above, the multi-settlement start-up and shut-down cost equations for the intraday and real-time stages are as follows:

$$SUC^{s}_{ijh} = v^{s}_{ijh} \cdot SU_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.17}$$

$$SDC^{s}_{ijh} = w^{s}_{ijh} \cdot SD_{ij} \qquad \forall i \in I, \forall j \in J^{nw}_i, \forall h \in H \tag{E.18}$$

Shortfall

In general, shortfall in a market stage is defined as total cost that is eligible for compensation minus total revenue. If a unit has a positive shortfall, it will receive uplift. However, if a unit has a negative shortfall (or a shortfall equal to zero), it will not receive uplift. In the two-settlement structure, generator shortfall is calculated separately for the day-ahead and real-time markets. For the day-ahead stage, shortfall is found by subtracting the energy and reserve market revenues from the total costs (i.e. variable, start-up, shut-down, and no-load costs) associated with the day-ahead schedules. However, in the real-time stage, the shortfall calculation is different based on whether the generation and reserve adjustments are positive or negative. A positive real-time adjustment represents an increase in generation or reserve provision from the day-ahead schedule, whereas a negative adjustment in the real-time represents a decrease in generation or reserve provision from the day-ahead schedule and is referred to as buy-back. Units that are buying back energy or reserves in the real-time stage are not eligible for uplift, therefore shortfall should equal zero [24]. For this reason, there are four distinct cases for the real-time shortfall calculation:

1. If the energy adjustment and the reserve adjustment are both positive, the real-time shortfall equals the generator costs for the incremental production minus the real-time energy and reserve market revenues.

2. If the energy adjustment is positive and the reserve adjustment is negative, the real-time shortfall equals the generator costs for the incremental production minus the real-time energy market revenues. Since energy production is increasing in this situation, a plant may receive uplift (i.e. shortfall is positive) if total costs are greater than energy revenues. However, there is a buy-back of reserves, so no uplift is allocated (i.e. shortfall is zero) for the reserve provision.

3. If the energy adjustment is negative and the reserve adjustment is positive, the real-time shortfall equals zero. Since there is a buy-back of energy, no uplift is allocated (i.e. shortfall is zero) for the energy provision. Additionally, there is no cost for providing reserves, so no uplift is allocated (i.e. shortfall is zero) for the reserve provision either.

4. If the energy adjustment and the reserve adjustment are both negative, the real-time shortfall equals zero. Since there is a buy-back of energy and reserves, no uplift is allocated (i.e. shortfall is zero) for the energy or reserve provisions.

The generator shortfall calculations for the day-ahead and real-time markets are shown below:

Day-Ahead Shortfall

$$SF^{\phi}_{ijh} = VC^{\phi}_{ijh} + NLC^{\phi}_{ijh} + SUC^{\phi}_{ijh} + SDC^{\phi}_{ijh} - R^{\phi}_{ijh} \qquad \forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H \tag{E.19}$$

Real-Time Shortfall

$$\text{(If } x^{\omega}_{ijh} \geq 0 \text{ and } s^{\omega}_{ijh} \geq 0\text{): } SF^{\omega}_{ijh} = VC^{\omega}_{ijh} + NLC^{\omega}_{ijh} + SUC^{\omega}_{ijh} + SDC^{\omega}_{ijh} - ER^{\omega}_{ijh} - RR^{\omega}_{ijh}$$
$$\forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H \tag{E.20}$$

$$\text{(If } x^{\omega}_{ijh} \geq 0 \text{ and } s^{\omega}_{ijh} \leq 0\text{): } SF^{\omega}_{ijh} = VC^{\omega}_{ijh} + NLC^{\omega}_{ijh} + SUC^{\omega}_{ijh} + SDC^{\omega}_{ijh} - ER^{\omega}_{ijh}$$
$$\forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H \tag{E.21}$$

$$\text{(If } x^{\omega}_{ijh} \leq 0 \text{ and } s^{\omega}_{ijh} \geq 0\text{): } SF^{\omega}_{ijh} = 0 \qquad \forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H \tag{E.22}$$

$$\text{(If } x^{\omega}_{ijh} \leq 0 \text{ and } s^{\omega}_{ijh} \leq 0\text{): } SF^{\omega}_{ijh} = 0 \qquad \forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H \tag{E.23}$$

Generator shortfall in the multi-settlement market setting is found in a similar fashion. Day-ahead shortfall is calculated in the same way as the two-settlement design, while shortfall in the intraday and real-time stages are calculated like the real-time stage in the two-settlement, but for each stage separately. The formulation for the intraday and real-time shortfall is included below:

Intraday and Real-Time Shortfall

$$\text{(If } x^{s}_{ijh} \geq 0 \text{ and } s^{s}_{ijh} \geq 0\text{): } SF^{s}_{ijh} = VC^{s}_{ijh} + NLC^{s}_{ijh} + SUC^{s}_{ijh} + SDC^{s}_{ijh} - ER^{s}_{ijh} - RR^{s}_{ijh}$$
$$\forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H, \forall s \in S \tag{E.24}$$

$$\text{(If } x^{s}_{ijh} \geq 0 \text{ and } s^{s}_{ijh} \leq 0\text{): } SF^{s}_{ijh} = VC^{s}_{ijh} + NLC^{s}_{ijh} + SUC^{s}_{ijh} + SDC^{s}_{ijh} - ER^{s}_{ijh}$$
$$\forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H, \forall s \in S \tag{E.25}$$

$$\text{(If } x^{s}_{ijh} \leq 0 \text{ and } s^{s}_{ijh} \geq 0\text{): } SF^{s}_{ijh} = 0 \qquad \forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H, \forall s \in S \tag{E.26}$$

$$\text{(If } x^{s}_{ijh} \leq 0 \text{ and } s^{s}_{ijh} \leq 0\text{): } SF^{s}_{ijh} = 0 \qquad \forall i \in I, \forall j \in J^{nw}_{i}, \forall h \in H, \forall s \in S \tag{E.27}$$

Uplift

Finally, generator uplift is calculated separately for each market in the two-settlement design. If a unit has a positive shortfall when summed over the operating day, it will receive an uplift payment equal to that amount. The equations used to calculate day-ahead and real-time uplift are shown below:

$$UP_{ij}^{\phi} = \max\left[0, \sum_{h\in H} SF_{ijh}^{\phi}\right] \qquad \forall i \in I, \forall j \in J_i^{nw} \tag{E.28}$$

$$UP_{ij}^{\omega} = \max\left[0, \sum_{h\in H} SF_{ijh}^{\omega}\right] \qquad \forall i \in I, \forall j \in J_i^{nw} \tag{E.29}$$

In the multi-settlement market design, the day-ahead uplift is calculated in the same way as the two-settlement structure. However, the intraday and real-time shortfall values are considered to be adjustments from the day-ahead. Therefore, after summing all shortfall over the operating day and keeping only the positive values for each market stage, the uplift from the intraday and real-time stages are summed to create an "adjustment from the day-ahead" uplift value for each generator. The calculation for the multi-settlement uplift is as follows:

$$UP_{ij}^{\phi} = \max\left[0, \sum_{h\in H} SF_{ijh}^{\phi}\right] \qquad \forall i \in I, \forall j \in J_i^{nw} \tag{E.30}$$

$$UP_{ij}^{adj} = \sum_{s\in S}\left\{\max\left[0, \sum_{h\in H} SF_{ijh}^{s}\right]\right\} \qquad \forall i \in I, \forall j \in J_i^{nw} \tag{E.31}$$

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