# *Modeling unit commitment in political context: Case of China's partially restructured electricity sector*

# Modeling Unit Commitment in Political Context: Case of China's Partially Restructured Electricity Sector

Michael R. Davidson, *Student Member, IEEE*, J. Ignacio Pérez-Arriaga, *Life Fellow, IEEE*

***Abstract*—Restructuring an electricity sector entails a complex realignment of political and economic institutions, which may both delay and distort the achievement of satisfactorily competitive conditions. In research and planning for policy interventions in power systems under these varied regulatory environments, typical operational models may neglect important interactions between techno-economic criteria and political constraints, leading to poor understanding of underlying causes of inefficiency and to inappropriate recommendations. We develop tractable formulations of the unit commitment problem based on integer clustering of similar units that endogenize important political factors in the Northeast grid region of China. We demonstrate the importance of these interactions on operations and provide a set of options for researchers to explore further pathways for China's ongoing power system reforms. For example, wind integration, a key policy priority, is inhibited by the interaction of institutions limiting short- and long-term sources of flexibilities in inter-provincial trade.**

***Index Terms*—Power system modeling, power system economics, electricity deregulation, unit commitment (UC), renewable energy integration, combined heat and power (CHP).**

## NOMENCLATURE

**Sets**:

$g \in G$: generators
$t \in T$: time periods
$p \in P$: provincial nodes
$k \in K$: clustered generator types

**Decision Variables**:

$\boldsymbol{u}_{g,t} \in \{0,1\}$: commitment status of generator $g$ at time $t$
$\boldsymbol{v}^{up}_{g,t} \in \{0,1\}$: startup of generator $g$ at time $t$
$\boldsymbol{v}^{dn}_{g,t} \in \{0,1\}$: shutdown of generator $g$ at time $t$
$\boldsymbol{y}_{g,t} \geq 0$: production of generator $g$ at time $t$
$\boldsymbol{r}_{g,t}$, $\boldsymbol{s}_{g,t} \geq 0$: available up and down reserve capability of generator $g$ at time $t$
$\boldsymbol{w}_{g,t}$: auxiliary ramping variable of generator $g$ at $t$
$\boldsymbol{f}_{p,p',t}$: flow from $p$ to $p'$ at time $t$
$\boldsymbol{l}_{p,p',t}$: transmission losses due to flow $\boldsymbol{f}_{p,p',t}$
$\boldsymbol{h}_{g,t}$: reservoir level of hydro generator $g$ at $t$
$\mathbf{Y}_{p,k,t} \geq 0$: production of cluster $k$ in $p$ at $t$
$\mathbf{W}_{p,k,t}$: auxiliary ramping variable, cluster $k$ in $p$ at $t$
$\mathbf{R}_{p,k,t}$, $\mathbf{S}_{p,k,t} \geq 0$: up, down reserve capability (cluster)
$(\mathbf{U}_{p,k,t}, \mathbf{V}^{up}_{p,k,t}, \mathbf{V}^{dn}_{p,k,t}) \in (\mathbb{Z}_{\geq 0})^3$: commitment variables in clustered formulation

**Parameters**:

$d_{p,t}$: demand at $p$ at time $t$
$p^{var}_g$: variable cost of generator $g$
$p^{su}_g$: startup cost of generator $g$
$\underline{P}_g$, $\overline{P}_g$: minimum and maximum outputs of generator $g$
$\overline{F}_{p,p'}$: transmission flow limit from $p$ to $p'$
$W_{g,t}$: available wind power of generator $g$ at time $t$
$RD_g$, $RU_g$: down and up ramp rates of generator $g$
$MD_g$, $MU_g$: minimum down and up times of generator $g$
$\underline{RES}_t$, $\overline{RES}_t$: down and up reserve requirements at time $t$
$\underline{RES}_{p,t}$, $\overline{RES}_{p,t}$: down and up provincial reserve requirements in $p$ at time $t$
$H_g$: mean hydro inflow of generator $g$ over a timestep
$HL_{g,t}$, $t = \{1, |T|\}$: initial and final levels of generator $g$
$Q_{p,k}$: minimum generation quota at $p$ for generator type $k$
$\alpha$: tolerance for "equal shares" dispatch deviation

## I. INTRODUCTION

A wide range of countries have initiated some form of electricity sector restructuring since the 1980s, choosing to introduce competition into one or several segments of the traditional vertically-integrated utility (VIU) model of electricity supply. Motivations for these transitions are varied, ranging from expected efficiency benefits and relaxing of demands on public finance associated with the entry of private actors and capital, to regulatory goals of tackling state-owned and entrenched interests [1]–[3]. Nevertheless, due to differences in institutional make-up, resource endowments, regulatory philosophies and macro-economic conditions, among other factors, these transitions have been often protracted and incomplete [2]–[4]. In addition, increasing coordination even among neighboring well-established restructured systems can run into various institutional complications, such as the long road to establish a common European market [5] and addressing various interests in intertie markets in the western US interconnect [6]. These can lead to outcomes that deviate from efficient outcomes assuming ideal economic prescriptions

M. R. Davidson is with the Massachusetts Institute of Technology (MIT) Institute for Data, Systems, and Society, Cambridge, MA 02139 USA, and the MIT Joint Program on the Science and Policy of Global Change (email: michd@mit.edu).

J. I. Pérez-Arriaga is Professor & Director of the BP Chair on Energy & Sustainability, Instituto de Investigacion Tecnologica (IIT), Universidad Pontificia Comillas, 28015 Madrid, Spain, and Visiting Professor at MIT Sloan School of Management.

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are followed. Under these settings, it is important for policy-makers, regulators, and researchers to appropriately model and understand how transition electricity systems operate, and to set realistic baselines for policy analysis.

China, currently undergoing a long transition from a state-run VIU to competitive wholesale and retail markets, is an important area of power systems research due to its size and effects on global environmental challenges, as well as implications for other transitioning systems. Similar to other countries, unique institutional structures and entrenched relationships between government and industry have led to complications in ownership and regulatory reforms, delaying the introduction of competition [7]. In particular, a quota-based system whereby generation hours are guaranteed for generators at fixed prices was maintained during restructuring. This system, intended as interim until competitive conditions were achieved, has become one of the most difficult roadblocks to establishing price competition mechanisms [8].

Over the next several years, China is engaging in additional reforms to create competitive markets and address air pollution and climate change impacts of electricity generation [9]. Pilots primarily at the provincial level will test compatibility of incentives with existing institutions with the goal of moving all commercial and industrial electricity transactions to medium- to long-term contracts by 2020 [10], ensuring that a diverse set of rules in the sector will persist.

An essential recurring function of system operators in all varieties of regulated structures is the scheduling of startup/shutdown and dispatch of generators to meet expected load on a daily basis. This is typically solved using a unit commitment (UC) optimization which minimizes production cost subject to various technical constraints [11]–[19], though in China, due to its partial liberalization of operations, a complex mix of dispatch priorities exist that are not fully optimized [20]. In addition to ensuring economic and reliable operation of existing assets, the proper functioning of this dispatch optimization is also deemed essential in restructured markets to provide efficient long-term investment signals [21], [22]. Establishing the central position of UC in grid operations and reducing administrative constraints will thus be similarly important in China's restructuring efforts.

Much research into the UC model has been aimed at improving computational performance of the solution algorithm [12], [16], incorporating uncertainty [15], and widening the scope of decisions such as to include investments [13]. In terms of analyzing institutional factors and degrees of restructuring, the difference between zonal and nodal market designs is an important area of research, especially as it relates to integrating renewable energy through market coupling mechanisms [23]. No UC work to the best of the authors' knowledge has focused on modeling operations under political constraints established during transition such as China's generation quota, though the concept has been included at a higher level in some planning models for China [24].

This paper formulates a new UC model with details of key political institutions influencing system operations in China and applies it to China's Northeast Grid. The quota introduces a long-term coupling constraint causing computational time and convergence difficulties in typical UC formulations. To facilitate consideration of the quota and run sensitivities over uncertain political parameters, we advance a clustering technique traditionally designed to speed computation in planning models that makes similar units identical and generalizes binary commitment variables to integer variables. The paper's main contributions are to:

1) Modify UC to include several political interventions in China's partially-restructured electricity sector and quantify their interactions;
2) Demonstrate tractable approach with acceptable errors using similar unit clustering to optimize generator scheduling under annual generation quota coupling constraints;
3) Calculate the suite of interactive effects of political and technical constraints on two distinct outcomes—cost and wind integration—relevant for modelers and policy-makers.

## II. Partial Liberalization of Operation

Since the 1980s, when China's generation sector was opened up to investment other than the primary network owner, China has struggled to define and implement consistent rules for generator access to the transmission network. For two decades, multiple generation owners competed with assets of the central state-run VIU in the absence of prices or other unambiguous criteria for deciding dispatch, leading to claims of discrimination [25]. In 2002, the current unbundled arrangement was established, and a system of "benchmark electricity tariffs" reflecting province-wide costs and affordability became the primary price-setting mechanism [26]. In other countries, stranded assets and insufficient compensation as a result of a transition to wholesale power markets are sometimes handled by side-payments from the regulator [27]. However, no comprehensive system of transition payments was created in China, the absence of which creates political pressure to maintain production from inefficient generators.

In the absence of differentiating price signals other criteria are used to determine the dispatch order. First, minimum generation quotas are allocated to generators on an annual basis. Because there is no consistent method to adjust benchmark tariffs to respond to cost differences, these quantities help guarantee sufficient revenues for less efficient generators [28]. Medium-term contracts (monthly to annually) directly between generators and consumers have been increasing in recent years, and are a major thrust of ongoing market reforms [10]. Similar to quotas and to other physical OTC contracts, the dispatch operator should prioritize meeting the quantities set out by these contracts [29].

Second, the foundational dispatch principles established following unbundling specify "transparent, fair and just" dispatch [30], which is interpreted as an "equal shares" principle, whereby generators should receive roughly the same share of generation to maintain equity [28].

Third, since 2007 there has existed another grid management priority known as "energy-efficient dispatch", which prioritizes first renewables, nuclear, and must-run generation, and continuing with coal units in decreasing order of efficiency [31]. Related policies established in 2006 and reiterated subsequently also mandate renewable energy integration [32], though there is no reported instance of curtailment compensation. The latest version—known as "green dispatch"—has high-level support, though there are no specifics yet on how it differs from "energy-efficient dispatch". Since short-run production costs are predominantly fuel, this priority is directionally similar to merit order dispatch. Implementation across the country has been uneven, however, in part because this may directly conflict with the first and second criteria. While prices have a questionable impact on short-term dispatch decisions, they do have a large impact on investment decisions and quota-setting, outside the scope of this model.

Finally, generator-specific operational restrictions are either determined administratively for generic unit types or self-reported by generators themselves, which tend to be conservative. Commitment costs are rarely compensated, leading to preferences for long minimum up times (of a week or longer) [33]. The over-conservativeness of these self-reported arrangements leading to efficiency losses has been observed in other partially-restructured systems, such as Spain in the 1990s [34].

Defining relevant balancing areas for power system operation can be ambiguous in China as dispatch centers at the provincial, regional (6 in total, consisting of 3-6 provinces each), and national levels all have degrees of autonomy [35]. Generation quotas and other dispatch priorities are determined at the provincial level, hence a large fraction of generators are still dispatched at the province. Adjustments for planned over-/under-supply can be negotiated through inter-provincial transmission capacity in annual plans and coordinated by the regional dispatch operator, with limited ability to respond to short-term changes in system conditions [20].

## III. Model

### A. Standard Unit Commitment

The standard UC problem seeks to minimize operational costs of meeting a given electricity demand, whose objective consists of variable generation costs and the startup (commitment) costs of thermal generators. We start with classic formulations [11] and linearize the objective function [12]:

$$\min \quad \sum_{g \in G} \sum_{t \in T} \left( p_g^{su} \boldsymbol{v}_{g,t}^{up} + p_g^{var} \boldsymbol{y}_{g,t} \right) \tag{1}$$

where $\boldsymbol{y}_{g,t}$ is the dispatch (continuous) level and $\boldsymbol{v}_{g,t}^{up}$ the startup decision of generator $g$ at time $t$, $p_g^{var}$ and $p_g^{su}$ are variable and startup costs (respectively) of generator $g$, $G$ is the set of generators, $T$ the set of time periods. Throughout, **bold typeface** refer to decision variables. This is subject to electricity demand and transmission constraints (Kirchhoff's first law):

$$\sum_{g \in G_p} \boldsymbol{y}_{g,t} - \sum_{p' \neq p} \left[ \boldsymbol{f}_{p,p',t} + \boldsymbol{l}_{p,p',t}/2 \right] = d_{p,t} \ , \forall p \in P, t \in T \tag{2}$$

where $d_{p,t}$ is the electricity demand at provincial node $p$ at time $t$, $\boldsymbol{f}_{p,p',t}$ is transmission flow from $p$ to $p'$ at time $t$, and $\boldsymbol{l}_{p,p',t}$ is the non-negative transmission loss associated with that flow. Intra-provincial networks are not considered in this analysis, due to unavailability of reliable data on transmission parameters, and because accounting for the quota requires clustering at the provincial level. Further, inter-provincial lines are assumed to be connected to provincial geographic centers for the purpose of estimating losses. These assumptions imply that the network no longer corresponds to an exact physical description, and angles calculated through Kirchhoff's second law would not be realistic. This modeling choice could affect aggregate inter-provincial flows and overestimate effective transmission interconnection.

In longer-time horizon models such as unit commitment or expansion planning, losses are typically ignored (e.g., [12]). However, given the large geographic distances, we felt that losses should not be neglected, and adopt piece-wise linear losses in terms of flow variables [36], described in [37].

Generator constraints on production and commitment:

$$\boldsymbol{u}_{g,t} \underline{P}_g \leq \boldsymbol{y}_{g,t} \leq \boldsymbol{u}_{g,t} \overline{P}_g \ , \ \forall g \in G_{thermal} \tag{3}$$

$$0 \leq \boldsymbol{y}_{g,t} \leq W_{g,t} \ , \ \forall g \in G_{wind} \tag{4}$$

$$\boldsymbol{w}_{g,t} = \boldsymbol{y}_{g,t} - \boldsymbol{u}_{g,t} \underline{P}_g \tag{5}$$

$$\begin{aligned} \boldsymbol{w}_{g,t} - \boldsymbol{w}_{g,t-1} &\leq RU_g && (6) \\ \boldsymbol{w}_{g,t-1} - \boldsymbol{w}_{g,t} &\leq RD_g && (7) \\ \boldsymbol{u}_{g,t} &\geq \sum_{t'=t-MU_g}^{t} \boldsymbol{v}_{g,t'}^{up} && (8) \\ 1 - \boldsymbol{u}_{g,t} &\geq \sum_{t'=t-MD_g}^{t} \boldsymbol{v}_{g,t'}^{dn} && (9) \\ \boldsymbol{u}_{g,t} - \boldsymbol{u}_{g,t-1} &= \boldsymbol{v}_{g,t}^{up} - \boldsymbol{v}_{g,t}^{dn} && (10) \\ & \forall g \in G_{thermal}, t \in T \end{aligned}$$

where ($\boldsymbol{v}_{g,t}^{up}$, $\boldsymbol{v}_{g,t}^{dn}$) are startup and shutdown decisions, $\boldsymbol{w}_{g,t}$ is an auxiliary ramping variable, ($\underline{P}_g$, $\overline{P}_g$) are minimum and maximum outputs, ($RU_g$, $RD_g$) are maximum upward and downward ramp rates, ($MU_g$, $MD_g$) are minimum up and down times, and $W_{g,t}$ is the available wind power by wind generator $g$ at time $t$. To ensure feasibility of ramping and commitment decisions at the beginning and end of the time period, periodic boundary conditions are assumed (i.e., for negative time indices $-t' \equiv T - t'$).

Combined heat and power (CHP) for district heating is widespread in northern China [38]. These primarily coal-fired cogeneration units have distinct operational constraints co-dependent on heat and electricity output, leading to increasing $\underline{P}_g$ and decreasing $\overline{P}_g$ with heat output [39], which for this paper are assumed constant over the day.

Spinning reserves are provided by committed non-CHP units and hydropower:

$$\begin{aligned} \boldsymbol{r}_{g,t} &\leq \boldsymbol{u}_{g,t} \overline{P}_g - \boldsymbol{y}_{g,t} && (11) \\ \boldsymbol{s}_{g,t} &\leq \boldsymbol{y}_{g,t} - \boldsymbol{u}_{g,t} \underline{P}_g && (12) \\ \boldsymbol{r}_{g,t} &\leq RU_g && (13) \\ \boldsymbol{s}_{g,t} &\leq RD_g && (14) \\ & \forall g \in G_{res}, t \in T \end{aligned}$$

$$\sum_{g\in G_{res}} \boldsymbol{r}_{g,t} \geq \overline{RES}_t,\ \forall t\in T \tag{15}$$

$$\sum_{g\in G_{res}} \boldsymbol{s}_{g,t} \geq \underline{RES}_t,\ \forall t\in T \tag{16}$$

where $(\boldsymbol{r}_{g,t},\ \boldsymbol{s}_{g,t})$ are upward and downward reserve variables, $(\overline{RES}_t,\ \underline{RES}_t)$ are upward and downward system-wide reserve requirements, and $G_{res} = G_{hydro} \cup G_{thermal} \setminus G_{CHP}$ is the set of generators providing reserves.

### *B. Hydropower*

We consider hydropower as a flexible resource over the model horizon, with inflows given by historic generation and fixed initial and final states, and minimum and maximum reservoir levels:

$$\boldsymbol{h}_{g,t} - \boldsymbol{h}_{g,t-1} = H_g - \boldsymbol{y}_{g,t} \tag{17}$$

$$\boldsymbol{h}_{g,t} = HL_{g,t}\ ,\ t\in\{1,|T|\} \tag{18}$$

$$\overline{HL}_g \geq \boldsymbol{h}_{g,t} \geq \underline{HL}_g \geq 0 \tag{19}$$

$$\forall g\in G_{hydro}, t\in T$$

where $\boldsymbol{h}_{g,t}$ is the reservoir level in units of generation, $H_g$ is mean inflow of generator $g$ over a timestep, $HL_{g,t}$ for $t = \{1,|T|\}$ are the fixed initial and final levels, and $\underline{HL}_g, \overline{HL}_g$ are lower and upper reservoir levels, respectively.

### *C. Partially Restructured Operation*

Due to the partial restructuring of China's electricity sector outlined in Sec II, the formulation (1)-(19) does not represent the decision-making situation faced by grid operators. We introduce here a new formulation that captures essential features of China's partially restructured operation.

*1) Provincial Dispatch:* We propose a single-objective formulation where the unconstrained model (1)-(19) represents the ideal reference, and we subsequently add restrictions to better reflect reality and evaluate efficiency losses. We identify at least two important changes that occur when dispatch is no longer centralized across provinces: transmission line capacities are constrained below their limits, and reserve requirements must be calculated separately for each province. These reflect, respectively, *long-term inflexibilities* associated with inter-provincial transmission contracts and *short-term inflexibilities* due to coordination challenges between distinct operators in charge of balancing operations ($\leq$ 1 hour).

Inter-provincial transmission constraints are derived from annual energy production and consumption planning, and then converted to power transfers on sub-monthly scales [28]. In the absence of granular temporal data (e.g., weekly or daily), transmission limits are modeled as uniform limits on transmission interconnection capacities $\overline{F}_{p,p'}$ based on historic annual aggregate transfers over major flow directions.

We also require each province to meet its reserve requirements internally, enforcing (15)-(16) for $\underline{RES}_{p,t}, \overline{RES}_{p,t}$.

*2) Minimum Generation Quotas:* Similar to modeling hydro-thermal coordination and mid-term maintenance scheduling, the requirement that each generator achieves a minimum amount of generation over the course of the year introduces a large coupling constraint. Extending the time horizon $T$ to an entire year would require significant simplifications to remain tractable, therefore we propose minimum generation constraints on aggregated similar cost units, set at the seasonal level. This allows, for example, a unit to not be committed during the model horizon without violating its annual quota. Instead, all generators of a given type $k$ must collectively meet the quota, as the clustered unit variables include only the total number of committed generators and the generation from those generators. Meeting this quota for each week in the quota timeframe (e.g. winter heating season) ensures that all generators on average can achieve their quota. This is similar to solving the entire problem simultaneously except for 1) possible underestimation of commitment costs outside of the week; and 2) any commitment time constraints at the model boundary (assumed repeating), which are likely small because startup times $\ll$ 168 hours.

As similar cost units, the result from an aggregate constraint on production over horizon $T$ should not differ significantly from imposing the constraint on each individual generator over the year, with the possible exception of underestimating commitment costs. The quota constraint is given by:

$$\sum_{g\in G_{p,k}} \sum_{t\in T} \boldsymbol{y}_{g,t} \geq Q_{p,k}\cdot|T|\cdot \sum_{g\in G_{p,k}} \overline{P}_g,\ \forall p\in P, k\in K \tag{20}$$

where $k \in K$ indexes clustered generators and $Q_{p,k}$ is the capacity factor quota. In Sec IV-D we construct these weekly quotas from annual and seasonal data.

*3) "Equal Shares" Dispatch:* While the quota is designed to ensure sufficient revenues, the "equal shares" dispatch principle seeks to ensure equitability across generators. It can be interpreted as the lack of a merit order principle, such as laid out in "energy-efficient dispatch", which distinguishes between generators based on efficiency. In the standard model runs, we assume a merit order principle, and perform a separate sensitivity for equal shares in Sec V-B, specified relative to the most efficient generator $k^* = coal600$, with $\alpha = 0.05$ as a tolerance parameter:

$$\frac{\sum_{t\in T, g\in G_{p,k}} \boldsymbol{y}_{g,t}}{\overline{P}_k\,|G_{p,k}|} \leq (1+\alpha)\,\frac{\sum_{t\in T, g\in G_{p,k^*}} \boldsymbol{y}_{g,t}}{\overline{P}_{k^*}\,|G_{p,k^*}|} \tag{21}$$

$$\frac{\sum_{t\in T, g\in G_{p,k}} \boldsymbol{y}_{g,t}}{\overline{P}_k\,|G_{p,k}|} \geq (1-\alpha)\,\frac{\sum_{t\in T, g\in G_{p,k^*}} \boldsymbol{y}_{g,t}}{\overline{P}_{k^*}\,|G_{p,k^*}|} \tag{22}$$

$$\forall p\in P, k\in K$$

### *D. Clustering*

The appropriate UC model for China must include the complicating constraint arising from the annual generation quota. Considering the entire year would be intractable, and even at shorter time scales, this coupling constraint can slow convergence, in ways analogous to incorporating unit startup/shutdown decisions into expansion planning models. Reduction techniques generally fall into categories of time dimension reduction techniques through the use of representative days and weeks [15], [18] and homogeneous or similar unit clustering [13], [19]. We employ here a formulation based on [13] that clusters multiple binary commitment variables of similar units $(\boldsymbol{u}_{g,t},\ \boldsymbol{v}^{up}_{g,t},\ \boldsymbol{v}^{dn}_{g,t})$ into integer variables over the combined cluster of generators $(\mathbf{U}_{p,k,t},\ \mathbf{V}^{up}_{p,k,t},\ \mathbf{V}^{dn}_{p,k,t})$, indexing over clustered generator types $k \in K$. We extend the formulation in [13] to a multi-node system, testing the validity of this approximation in Sec V-A. Wind and hydropower are aggregated at the provincial level for all formulations and do not require special treatment.

This is mostly a "drop-in" formulation, with equation structures of (1)-(19) unchanged and only variable substitutions to their clustered equivalents and summed over indices $p \in P, k \in K$. The full cluster model is given by (23)-(38) below and the wind and hydro equations (4), (17)-(19), unaffected by clustering. Throughout, **bold** capitalized variables refer to their clustered equivalents (e.g., $\mathbf{W}_{p,k,t}$ is the clustered $\boldsymbol{w}_{g,t}$).

$$\min \quad \textstyle\sum_{p\in P}\sum_{k\in K}\sum_{t\in T}\left(p_k^{su}\mathbf{V}_{p,k,t}^{up} + p_k^{var}\mathbf{Y}_{p,k,t}\right) \tag{23}$$

$$\sum_{k\in K}\mathbf{Y}_{p,k,t} - \sum_{p'\neq p}\left[\boldsymbol{f}_{p,p',t} + \boldsymbol{l}_{p,p',t}/2\right] = d_{p,t} \tag{24}$$
$$\forall p \in P, t \in T$$

$$\underline{P}_k\mathbf{U}_{p,k,t} \leq \mathbf{Y}_{p,k,t} \leq \overline{P}_k\mathbf{U}_{p,k,t} \tag{25}$$
$$\forall p \in P, k \in K, t \in T$$

$$\mathbf{W}_{p,k,t} = \mathbf{Y}_{p,k,t} - \underline{P}_k\mathbf{U}_{p,k,t} \tag{26}$$
$$\mathbf{W}_{p,k,t} - \mathbf{W}_{p,k,t-1} \leq \mathbf{U}_{p,k,t}RU_k \tag{27}$$
$$\mathbf{W}_{p,k,t-1} - \mathbf{W}_{p,k,t} \leq \mathbf{U}_{p,k,t}RD_k \tag{28}$$
$$\forall p \in P, k \in K, t \in T$$

$$\mathbf{R}_{p,k,t} \leq \overline{P}_k\mathbf{U}_{p,k,t} - \mathbf{Y}_{p,k,t} \tag{29}$$
$$\mathbf{S}_{p,k,t} \leq \mathbf{Y}_{p,k,t} - \underline{P}_k\mathbf{U}_{p,k,t} \tag{30}$$
$$\mathbf{R}_{p,k,t} \leq \mathbf{U}_{p,k,t}RU_k \tag{31}$$
$$\mathbf{S}_{p,k,t} \leq \mathbf{U}_{p,k,t}RD_k \tag{32}$$
$$\forall p \in P, k \in K, t \in T$$

$$\sum_{p\in P}\sum_{k\in K_{res}}\mathbf{R}_{p,k,t} \geq \overline{RES}_t,\ \forall t \in T \tag{33}$$

$$\sum_{p\in P}\sum_{k\in K_{res}}\mathbf{S}_{p,k,t} \geq \underline{RES}_t,\ \forall t \in T \tag{34}$$

Some modifications to the commitment state equations (8)-(10) are required, in terms of the number of units in each cluster $|G_{p,k}|$:

$$\mathbf{U}_{p,k,t} \leq |G_{p,k}| \tag{35}$$

$$\mathbf{U}_{p,k,t} \geq \sum_{t'=t-MU_k}^{t}\mathbf{V}_{p,k,t'}^{up} \tag{36}$$

$$|G_{p,k}| - \mathbf{U}_{p,k,t} \geq \sum_{t'=t-MD_k}^{t}\mathbf{V}_{p,k,t'}^{dn} \tag{37}$$

$$\mathbf{U}_{p,k,t} - \mathbf{U}_{p,k,t-1} = \mathbf{V}_{p,k,t}^{up} - \mathbf{V}_{p,k,t}^{dn} \tag{38}$$
$$\forall p \in P, k \in K_{thermal}, t \in T$$

## IV. Experimental Setup

We demonstrate these formulations on the Northeast China Grid (NE), one of five major grid regions in the State Grid Corporation of China, consisting of four distinct service territories: Heilongjiang (HL), Jilin (JL), Liaoning (LN), and Inner Mongolia-East (IME). The NE grid is recognized for its high degree of operational inflexibility, owing to the large penetration of coal-fired CHP, relative lack of flexible generation such as hydropower and natural gas, and overcapacity in thermal generation [40]. Wind curtailment reached 32%, 21% and 10% in Jilin, Heilongjiang and Liaoning provinces, respectively, in 2015 [41]. In our formulation, the NE grid is considered to be isolated from neighboring grids: only 21.5 TWh, or 5% of total generation, was exported to North China Grid in 2014 [42].

The UC model is formulated for a one-week horizon (168-hour time steps), and in each run, the model is solved six times for different scenarios of wind production while keeping other inputs such as demand constant. All results shown are the average of these six wind scenarios (e.g., average curtailment rates are calculated from sum totals of wind curtailment and production). A week from the winter heating season is used for most of the analysis due to its higher wind curtailment rates, and for comparison, results from the summer season are discussed in Sec V-D. Periodic boundary conditions are assumed and the entire week's results are kept. The horizon should be longer than typical operational scales of 1-3 days in order to justify the assumption of aggregating production quotas across like units as in (20). The week is chosen to capture daily variations in utilization patterns of generation types and to reasonably reflect the timescale of scheduling and dispatch decision-making of Chinese grid operators. While a longer timeframe would be better from the perspective of making the quota constraint more flexible, it could also complicate tractability and would ignore week-to-week changes and the issues of long-term forecasting, explored in Sec V-C.

The models are implemented in GAMS and solved using ILOG CPLEX 12.6.2. Each scenario is run using up to 8 parallel threads on a dual-socket 12-core 2.5 GHz Intel Xeon machine with 128 GB RAM. The MIP optimality tolerance is set to $10^{-3}$ and resource limit to 360 minutes.

### A. Generator Characteristics and Clustering

The NE grid in our reference year has three basic types of generators: coal, hydropower, and wind. Coal-fired units in NE range in size from 6 MW up to 1000 MW, and an historical database of thermal plant-level data for 2011 (calculated at end of 2010) was chosen as an authoritative source for this analysis [43]. This wide distribution of unit sizes impacts efficiency and generator constraints important for commitment and dispatch schedules, and will be the main source of variation in production costs for the system. These plant level data were further converted to unit-level data (for the case of multiple units inside the fence) and identified as electricity-only or CHP through information obtained in the plant names, generation company websites and other public sources. Total thermal capacities were matched with provincial statistics [44]. While there are some published aggregate statistics on fractions of CHP [40], [45], they are highly varied. We feel our unit-level approach is consistent with the purposes of the modeling exercise, and run sensitivities on the effective must-run outputs. This resulted in 507 thermal units.

Next, we clustered thermal units into six different sizes we observed frequently during the above cross-checking: 25, 50, 135, 200, 350 and 600 MW. Units were clustered according to the closest size threshold (either above or below) – in contrast to [46] that uses sizes as upper thresholds – which produces average capacities closer to the thresholds. Combined with the binary CHP indicator, this leads to 12 clusters per province. These clustered sizes were used to determine the heat rates of the various generators. In order to have comparable unit types across provinces, we let the homogenized unit have the average capacity of units in all provinces for a given type. The generation mix is heterogeneous across provinces, with JL on one end with high must-run CHP and low electricity-only coal, and IME on the other with virtually no CHP. Electricity-only coal accounts for 28.2%, 52.4%, 58.6%, and 72.7% of total capacity in JL, HL, LN and IME, respectively. CHP capacity accounts for 40.0%, 33.9%, 25.4%, and 5.9% of total capacities, respectively.

Finally, we must specify exogenously which must-run units will be committed. Again, previous work [40], [45] can guide this determination, but are also subject to data reliability concerns. As our reference, we remove cogeneration units from each province roughly equally across sizes in order to achieve an approximate 80% commitment rate. The set of clustered generators given this 80% commitment is in Table III and generator parameters are in Table IV. We explore the implications of this choice with an additional sensitivity in Sec V-D.

### B. Network

Identifying each province as a node, inter-provincial transmission is modeled using a transport model satisfying Kirchhoff's first law. Distances between NE province centers (nodes in this study) range from 300-800 km and are at 345kV, 500kV and ±500kV [47]. Loss coefficients $\mu_{p,p'}$ were estimated by summing in parallel the resistive losses for typical lines of a given voltage: for example, a 500-kV line with 1000-MW loading has a loss rate of 1.3% per 100 miles (161 km) [48]. Interconnection capacities were estimated using Surge Impedance Loading at 500 km [49]. Ignoring Kirchhoff's second law could have implications for modeled flows over AC lines, as described above (excluding the 3-GW ±500kV DC line connecting IME-LN).

In practice, as transmission capacity is allocated on an annual basis, the effective transmission interconnection capacities $\overline{F}^*_{p,p'}$ under provincial dispatch are lower and estimated as in Sec III-C1. Furthermore, in accordance with clear export/import relationships in government documents [50], some transmission interconnections were assumed to be uni-directional. We note that Heilongjiang and Liaoning, which do not share an interconnection, have an export/import relationship in transmission pricing and summary statistics [50], reflecting coordination in the annual energy and transmission plan allocation process of over-generation in Heilongjiang and under-generation in Liaoning, as politicians are primarily concerned with total energy transfers. Rather than constrain the demand balances at these two nodes to meet energy transfer requirements, we simplify this relationship by establishing an artificial direct transmission link, whose distance is the sum of the intermediate paths and resistance calculated in series. As only Kirchhoff's first law is modeled in our network representation, these two approaches are equivalent.

Reserve requirements are held constant over the week, set at the province by its peak load, wind capacity and largest unit as contingency. Additional reserve requirements due to wind power are difficult to estimate, but 4% of wind capacity is a reasonable upper end for most systems [51]. Regulation and load-following reserves in total are set at 3% of peak load:

$$\begin{aligned}\overline{RES}_p &= 3\% \cdot MaxLoad_p + 4\% \cdot WindCap_p \\ &\quad + LargestUnit_p \qquad (39)\\ \underline{RES}_p &= 3\% \cdot MaxLoad_p + 4\% \cdot WindCap_p \qquad (40)\end{aligned}$$

where $LargestUnit_p = 700$ MW is a contingency reserve, $\overline{RES}_p$ is the up reserve requirement for $p$, and $\underline{RES}_p$ is the down reserve requirement. This results in up reserve requirements of $6.1\% \sim 17.4\%$ depending on the province. Region-wide reserves, in scenarios where reserves can be shared across borders, are the sums of and replace provincial requirements ($9.1\%$ for up reserves).

### C. Demand, Wind and Hydropower Resource Profiles

A single representative week of electricity load from March 2011 for each province is used for all scenarios, reconstructed from daily consumption data in the winter season similar to the procedure described in [52], shown in Figure 1. Province-wide average wind capacity factors were generated as in [52] using Modern Era Retrospective-analysis for Research and Applications (MERRA) boundary layer flux data, a high temporal resolution (one hour) atmospheric dataset with $0.5°$ latitude by $0.67°$ longitude spatial resolution (approx. 56 km x 61 km at mid-latitudes). After excluding certain areas (e.g., forests, urban areas, ...), the power curve of a Sinovel 1.5-MW wind turbine with 82-meter hub height was used in each cell, and averaged to form the province-wide capacity factor $W_{g,t}$ in (4). To capture variability of wind resources, six weeks from the model year (2011) were chosen: three each from January and March, winter months when wind is most plentiful and constraints from CHP generation create the greatest inflexibilities. The minimum of these six was also generated to aid with finding an initial feasible integer solution, and to test the effect of forecast error on solutions. The same process was used to generate summer weeks for Sec V-D.

Hydropower generators are modeled by (17)-(19) using historical generation data from 2001-2014 for the Northeast provinces [53]. $H_g$, the mean inflow of generator $g$ over the problem timestep, is given by dividing generation equally throughout the winter months (Jan-Mar). $HL_{g,1} = HL_{g,|T|} \gg H_g$ are the fixed initial and final levels. The minima of hydro generation in each month over the period were used, accounting for 1.6% of generation. The main results are robust to taking the maxima of hydro generation over the period: increasing hydro availability in the model decreases total production costs but does not change the relative impacts of regulatory formulations on objectives or wind outcomes.

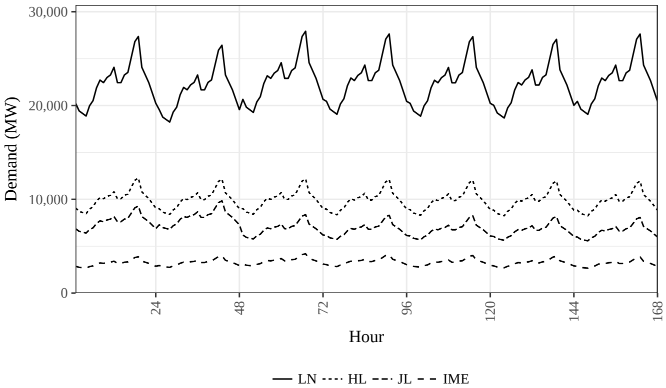


Figure 1. Winter demand profiles by province

Table I
SOLUTION TIMES FOR BINARY (FULL UNITS), AGGREGATED-BINARY (12-TYPE) AND AGGREGATED-INTEGER (CLUSTERED) FORMULATIONS. (MINUTES)

| RUN | FULL UNITS | 12 TYPE | CLUSTER |
|---|---|---|---|
| R | 18.19 | 12.90 | 1.59 |
| P | 22.37 | 15.26 | 1.35 |
| RT | 160.00 | 480.52* | 2.32 |
| PT | 101.14 | 1996.62* | 1.84 |
| RQ | | 317.68 | 4.46 |
| PQ | | 774.21* | 40.16 |
| RTQ | | 627.33* | 9.42 |
| PTQ | | 2522.04* | 69.53 |

R: Regional reserves. P: Provincial reserves.
T: Limited transmission. Q: Quota.
*One or more wind scenarios did not solve to optimality.

### D. Generation Quota

The quota is an annual minimum constraint on individual generators set at the provincial level, but clustering allows us to consider seasonal averages over sums of similar type units as in (20). Additionally, we cannot assume that the constraint is constant throughout the year as cogeneration units must be committed to provide district heating in the roughly six-month winter heating season. To calculate the heating season average, we assume that CHP units will achieve most of their quota during the high must-run winter months. By contrast, electricity-only units will predominate in the non-winter heating season. If the maximum capacity factor they can achieve in summer is 80% due to availability of units and common loadings, then we can approximate the minimum capacity factor they must achieve in the winter from annual averages. Due to data availability, we use average thermal capacity factors in 2012 [54], adjusting for inter-annual changes, and let quotas be constant across sizes (i.e., $Q_{p,k} = Q_p$).

## V. RESULTS

### A. Solution Performance and Effects of Clustering

The binary formulations (considering each unit's reported minimum and maximum output), with 346k variables (125k discrete) and 368k constraints following presolve, have varied performance in terms of solution times and optimality gaps when the coupling quota constraint is activated. We first solved for the optimum for the minimum wind scenario and used this as an initial feasible integer solution for subsequent wind scenarios. Solution times for all formulations are shown in Table I, inclusive of solving the initial minimum wind scenario. The aggregated binary formulation (units are homogenized into one of the twelve categories), with 337k variables (125k discrete) and 350k constraints, solution times unexpectedly increase dramatically for the limited transmission case. In addition, several wind scenarios do not converge, and a handful do not even find a feasible solution. The poor performance of the aggregated formulation compared to the full binary is likely attributable to the degeneracies of similar units, and further work could examine in what circumstances we might expect greater time penalties. In the clustered formulation (integer commitments), with 73k variables (2k discrete) and 55k constraints, times reduced by 30-1300x.

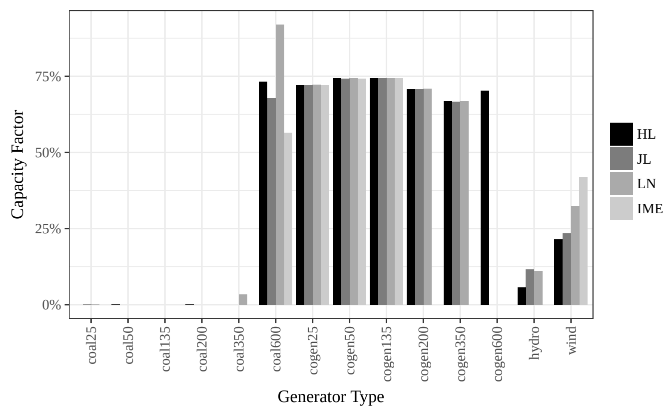


Figure 2. Capacity factors by province, reference case (full binary).

The standard model, in the absence of regulatory constraints, results in high capacity factors from must-run cogeneration units, wind, and high-efficiency coal ($coal600$). All other generators are relatively unused, and production from low-efficiency non-cogeneration units are basically zero (see Figure 2). JL has the highest fraction of CHP, requiring less generation from non-CHP units, while LN with the largest demand has over 80% utilization of $coal600$.

The two sequential simplifications of aggregation and clustering have a small impact on two outcome variables of interest: objectives are within $0.01\%$, and wind generation totals within $0.02\%$. These errors are magnified at the individual province, with objective errors ranging from $-1.2\% \sim +2.5\%$, and wind totals within $\pm 0.2\%$ (see Figure 3). Comparing the aggregated binary (12-type) and aggregated integer (Clustered) formulations, the errors introduced with respect to the full units binary formulation are of comparable magnitude, indicating that the step of aggregation (homogenizing similar units) introduces more error than changing the commitment variables from binary to integer.

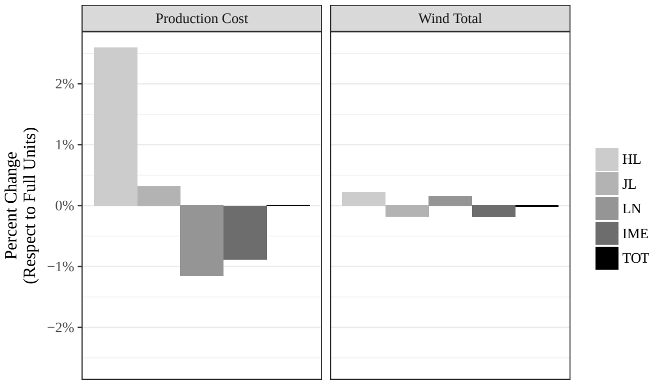


Figure 3. Clustering errors of production cost and wind generation totals by province, reference case.

## B. Effects of Political Constraints

In this section we present the effects of several aspects of China's partial liberalization: provincial reserves, limited transmission, minimum generation quota, and "equal shares" dispatch. As we add political constraints, total production costs increase, though the magnitude depends on the interaction of the imposed regulations (see Figure 4). Implementing only restrictions that disallow inter-provincial reserve sharing (P in Figure 4) does not differ significantly from the reference case (R), whose largest effect is shifting some high-efficiency coal from LN to JL for provincial reserves that JL's predominantly CHP units cannot provide.

Limiting transmission (T) increases costs by shifting some generation to less efficient *coal200* and *coal*350 available in HL and LN. The combination of within-province reserve requirements and limited transmission interconnection (PT) substantially decreases flexibility by raising coal outputs in certain areas, leading to higher costs and wind curtailment. This effect is largest in IME (see Figure 5). The minimum generation quotas for electricity-only coal plants also increase costs, but do not significantly affect wind curtailment for any combination of other parameters (e.g., PT $\rightarrow$ PTQ). Put another way, shifting production from high to low-efficiency generators to satisfy their quota does not significantly change the ability of the system to integrate wind energy.

Clustering commitment variables into integers allows us to test the effect of varying regulatory parameters over a wider range, both as sensitivities as well as to identify implications of policy changes. We show this for the case of modifying the quota in Figure 6. In it, we change the quota proportionally for each province, i.e. 1 is the base case, and 0 is the absence of a quota.

As the quota increases, the effect of limited transmission on the objective decreases, so that we see convergence of RTQ, PQ and RQ under high quotas. The interaction of transmission and within-province reserves is robust, however, to changes in quota. Wind curtailment is essentially flat for all values of the quota, demonstrating robustness of the results in Figure 4.

"Equal shares" dispatch is more costly than the minimum generation quota alone, as the optimal capacity factors of

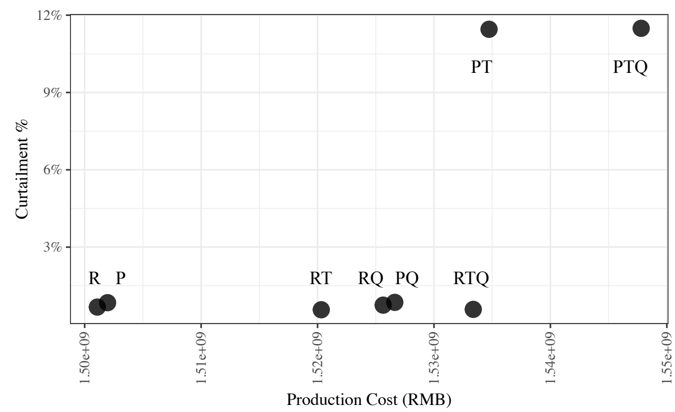


Figure 4. Objective and wind curtailment by regulatory formulations. R=Regional reserves, P=Provincial reserves, T=Limited transmission, Q=Quota.

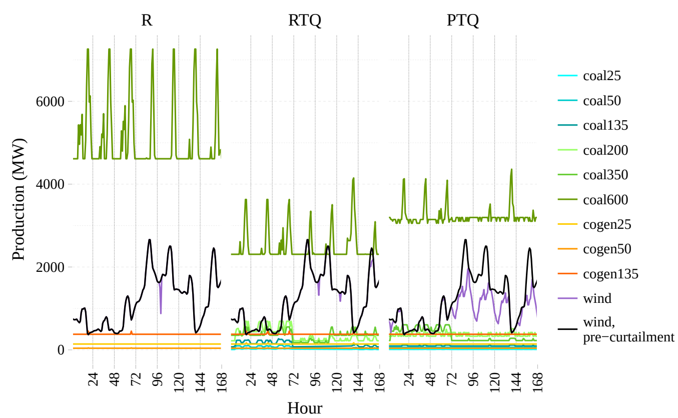


Figure 5. IME generation profiles for a January wind profile. R=Regional reserves, P=Provincial reserves, T=Limited transmission, Q=Quota.

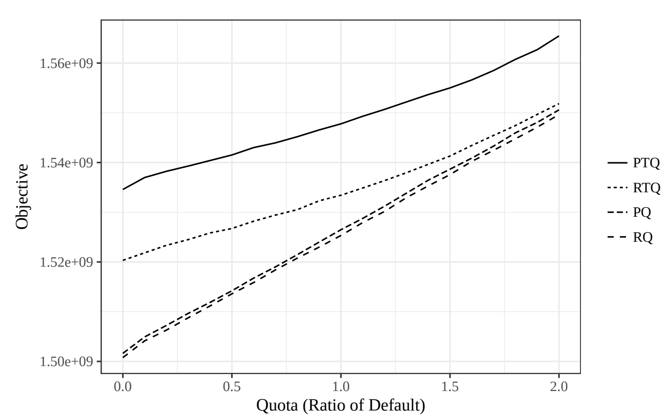


Figure 6. Objectives as a function of quota. R=Regional reserves, P=Provincial reserves, T=Limited transmission, Q=Quota.

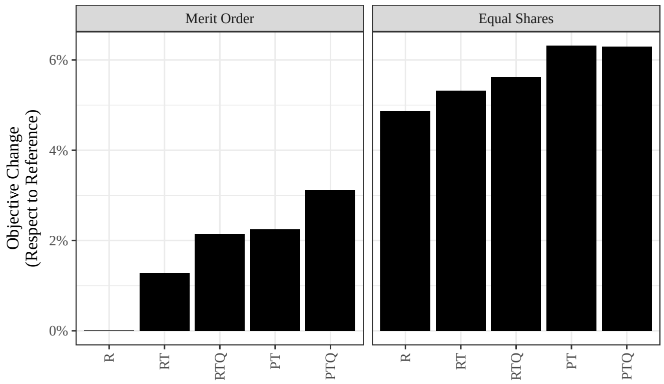


Figure 7. Objective change for "equal shares" dispatch (21)-(22) compared to default ("merit order"). R=Regional reserves, P=Provincial reserves, T=Limited transmission, Q=Quota.

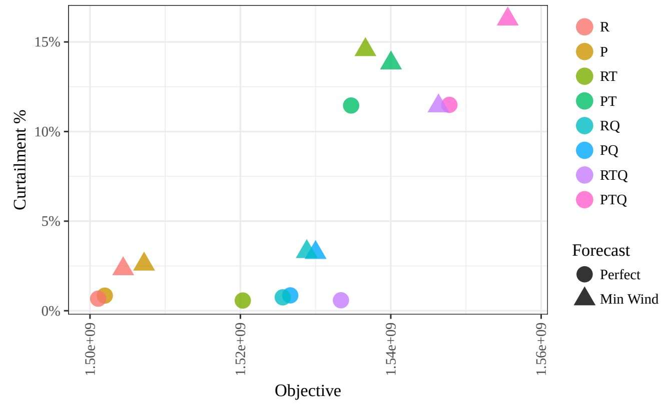


Figure 8. Two-stage model results simulating wind power uncertainty (Min Wind = commitments based on minimum wind profile). R=Regional reserves, P=Provincial reserves, T=Limited transmission, Q=Quota.

inefficient generators are higher than the minimum quota requirement $Q_{p,k}$ in almost all cases. Similar to the minimum quota, "equal shares" tends to increase production costs by generator switching, while leaving wind integration outcomes essentially unchanged, with one exception: imposing "equal shares" under a regional reserve-sharing scheme increases curtailment slightly to 4%. The most constrained case (PTQ with "equal shares") is roughly 6% more costly than the reference case (see Figure 7). As "energy-efficient dispatch" (merit order) is implemented inconsistently in practice, these two situations roughly bound the range of dispatch priorities.

### *C. Role of Wind Power Uncertainty*

The model (1)-(20) assumes deterministic wind and demand profiles, with a perfect forecast for the entire week. In practice, forecast errors can be significant on this time horizon. To better simulate real constraints of system operators and to determine how relevant forecast errors are to the overall conclusions of this paper, a two-stage model is constructed with commitments fixed prior to wind realizations. There is a significant body of UC work devoted to wind power uncertainty and how to tractably consider the properties of forecast errors in the unit commitment stage [55]. If the UC is performed daily, then day-ahead forecasts can provide information for better commitment scheduling. If the UC is performed weekly or longer (as is this system, described above), then forecast errors will be larger, and we propose a conservative scheduling procedure: committing units assuming a limited amount of wind power, equal to the minimum of the wind profiles in this study. Commitments are determined based on this "minimum wind" availability, and a second stage model optimizes dispatch based on the same set of deterministic wind scenarios. This retains some diurnal wind patterns of the season, providing a reasonable bound on the utility of forecasts given UC practices, and is directly comparable to the deterministic cases because realized wind is the same. For the "minimum wind" case, the wind capacity summand in (39)-(40) is eliminated. Previous work removes reserve constraints in the second stage [15], though we choose to retain them for contingency and load following.

Relative to perfect forecasts, the two-stage model increases both costs and curtailment. In contrast to perfect forecasts, incorporating uncertainty shows high curtailment for all limited transmission (T) cases, with less dependence on reserve sharing rules (see Figure 8). Hence, large forecast errors and over-conservative commitment schedules particularly enhance the impact of *long-term* transmission constraints. This demonstrates potential gains from better commitment schedules (such as shorter look-ahead, and improved forecasting models). However, at the same time, forecasting challenges can be partially mitigated with more flexible transmission.

### *D. Sensitivity to Must-Run Cogeneration*

As must-run levels are difficult to verify, we perform a sensitivity on the commitment rate of CHP. Compared to our reference (~80% commitments), a higher must-run threshold of ~90% commitments increases the fraction of the minimum load in provinces that must be met by cogeneration units: in the most extreme case, Jilin (JL), this ratio rises from 78% to 87%. Costs increase as more generation is substituted away from high-efficiency generators to smaller cogeneration. However, wind curtailment is insensitive ($<1\%$ change in curtailment rate) to adjusting this parameter over this range, likely because the largest modeled curtailment occurs in IME with very low CHP penetration. The outcomes of the political scenarios relative to the base case, for both low and high CHP commitments, do not substantively change. Must-run thresholds, minimum and peak loads for each province are in Table II.

We also simulate the effects of political constraints in the summer season, when there are no must-run CHP plants. Producing a set of six wind weeks (from June and September) and single demand week from summer, and increasing electricity-only plant quotas to 80% based on the same quota assumptions above, we find that wind curtailment is negligible (<1%) and costs are lower. In particular, generation is shifted from low-efficiency to high-efficiency generators in JL, and to generators in IME from other provinces. These demonstrate that must-run CHP and winter conditions can have a large

Table II
MUST-RUN THRESHOLDS BY COMMITMENT RATE, AND MINIMUM AND PEAK LOADS BY PROVINCE (MW)

| | Must-Run | | Min Load | Peak Load |
|---|---|---|---|---|
| | (80%) | (90%) | | |
| HL | 3,790 | 4,179 | 8,241 | 12,273 |
| JL | 4,334 | 4,815 | 5,571 | 9,840 |
| LN | 4,567 | 5,190 | 18,236 | 27,920 |
| IME | 556 | 556 | 2,657 | 4,189 |

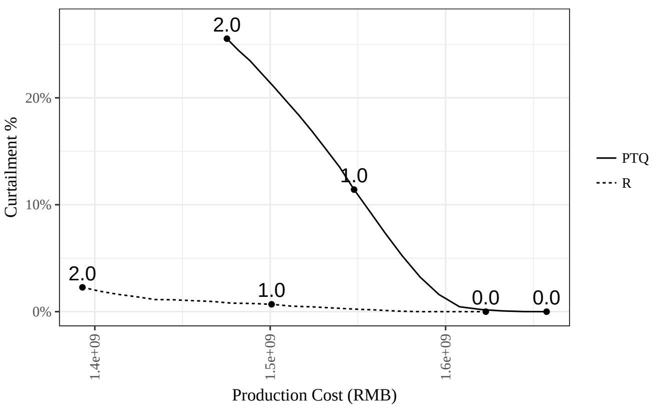


Figure 9. Costs and wind curtailment as a function of wind capacity (labels = multiples of base wind capacity). R=Regional reserves, P=Provincial reserves, T=Limited transmission, Q=Quota.

impact on wind integration. However, the inflexibilities are not additive: in summer, the relative effects of political constraints are enhanced: the total cost of the most constrained case (PTQ) is 6% above reference in summer, compared to only 3% in winter.

### *E. Sensitivity to Wind Penetration*

Varying wind capacity from 0 up to 2x the base case (21 increments), we find that, as expected, objectives fall and curtailment increases (see Figure 9). The cost effect is more pronounced for the reference case, while wind integration difficulties are enhanced for the constrained cases. Wind penetrations of R (reference) and PTQ (most constrained) increase from 7.9% and 7.0% in the base capacity to 15.5% and 11.8% with 2x capacity, respectively. Even with double the 2011 wind capacity, curtailment in the reference case is still only 2%.

## VI. DISCUSSION

Restructuring an electricity sector entails a complex realignment of political and economic institutions, which may both delay and distort the achievement of satisfactorily competitive conditions, and therefore efficiency. In research and planning for policy interventions in power systems under these varied regulatory environments, typical models assuming ideal operations may neglect important interactions between techno-economic criteria and political constraints, leading to poor understanding of underlying causes of inefficiency and to inappropriate recommendations. In this work, we have developed tractable formulations of a "sub-optimal" unit commitment problem that endogenize important political factors in a major grid region of China, demonstrating the importance of these on operations and providing a set of options for researchers to explore further pathways for China's ongoing power system reforms.

A quintessential feature of operations in China is the quota system, which allocates on an annual basis minimum generation amounts to generators that must be met in an equitable manner by the grid companies' dispatch centers, with implications for transmission capacity allocations and other decisions. This is a long-term coupling constraint similar to hydro-thermal coordination or maintenance scheduling, giving rise to similar modeling trade-offs in terms of time horizons and numbers of decision variables. After demonstrating the adequacy of our aggregation technique, we find that the quota is not the primary political factor driving wind integration challenges, over a rather wide range of presumed quotas and even under the more stringent "equal shares" dispatch principle. These raise questions on the efficacy of ongoing efforts to shift quotas to medium-term competitively-bid contracts and to prioritize high-efficiency generators through "energy-efficient dispatch", which can reduce system costs but have indeterminate impacts on wind integration flexibility. The next iteration—"green dispatch"—would need to address short-term dispatch priorities, rather than continuing to focus on plan-based allocation, to be effective. As price formation can be highly political, if and when bid-based spot markets develop, special efforts will need to be paid to how this stage may differ from cost minimization.

A well-known cause of inflexibility is the high must-run threshold of cogeneration units (CHP) during the winter heating season. We show that, similar to the quota, while this has clear impacts on total objective costs, it does not necessarily lead to poor flexibility causing high wind curtailment. Improving inter-provincial transmission can help add flexibility during key winter heating hours while still satisfying must-run heating requirements. Conversely, advancing restructuring efforts may be a necessary prerequisite to achieve proposed benefits of increased heat-electricity system flexibility, such as introducing flexible cogeneration and heat storage [56]. Small (<1%) modeled curtailment in all summer week cases show that addressing political constraints is primarily important for the winter in the case of the NE grid.

Under cost-minimizing dispatch, wind curtailment increases dramatically when inter-provincial trade is constrained in both the short-term (reserves) and the long-term (effective interconnection). Just one of these two sources of inflexibility alone is insufficient to change significantly wind integration outcomes. This highlights interactive effects of technical and political constraints that can only be captured in a unified model such as the one presented. These results scale with increasing wind penetration.

Wind power uncertainty and forecasting errors tend to enhance the effect of limited transmission interconnections, raising costs and curtailment mostly independent of the specific reserve-sharing rules. This demonstrates potential gains from better commitment schedules (such as shorter look-ahead, and improved forecasting models). However, at the same time, forecasting challenges in the modeled year can be mitigated with more flexible transmission.

Both of the simplified unit commitment models presented (aggregated and aggregated-clustered) provide several valuable avenues for further research. The models, while respecting the constraints of grid operators, assume a single optimizing agent. This should be seen as the best-case scenario for operating in political context, and additional studies into actual dispatch practices can create heuristics that capture the larger inflexibilities observed. Intra-provincial transmission constraints, ignored in this analysis, may be binding in some regions with rapid wind expansion and could be considered with a more detailed network.

Examination of the impact of individual political constraints can provide guidance for the relative importance of reform options under consideration to achieve near-efficient outcomes and facilitate other policy priorities such as renewable energy integration. Quantifying the benefits of, for example, improving coal unit commitment scheduling and minimum generation outputs can highlight the cost-benefit trade-offs inherent in modifying the current primarily administrative scheduling practices. Future work can expand to other network and generator configurations, and explore optimal unit aggregation techniques.

## VII. Appendix

Table III
CLUSTERED UNITS AND CAPACITIES (MW) BY PROVINCE, 80% CHP COMMITMENT

| | HL | | JL | | LN | | IME | |
|---|---|---|---|---|---|---|---|---|
| | # | Cap. | # | Cap. | # | Cap. | # | Cap. |
| coal: | | | | | | | | |
| 25 | 50 | 822 | 32 | 526 | 39 | 641 | 2 | 33 |
| 50 | 11 | 627 | 6 | 342 | 7 | 399 | 2 | 114 |
| 135 | 1 | 136 | 4 | 544 | 3 | 408 | 2 | 272 |
| 200 | 9 | 1,827 | 1 | 203 | 14 | 2,842 | 5 | 1,015 |
| 350 | 1 | 326 | 1 | 326 | 2 | 652 | 3 | 978 |
| 600 | 11 | 6,713 | 6 | 3,661 | 23 | 14,036 | 14 | 8,543 |
| cogen: | | | | | | | | |
| 25 | 65 | 1,410 | 8 | 174 | 69 | 1,497 | 9 | 195 |
| 50 | 11 | 583 | 2 | 106 | 5 | 265 | 1 | 53 |
| 135 | 1 | 127 | 3 | 381 | 6 | 762 | 4 | 508 |
| 200 | 2 | 400 | 16 | 3,200 | 8 | 1,600 | 0 | 0 |
| 350 | 8 | 2,448 | 8 | 2,448 | 8 | 2,448 | 0 | 0 |
| 600 | 1 | 600 | 0 | 0 | 0 | 0 | 0 | 0 |
| wind | 1 | 1,861 | 1 | 2,209 | 1 | 3,381 | 1 | 3,232 |
| hydro | 1 | 888 | 1 | 4,185 | 1 | 1,817 | 0 | 0 |
| Totals | 173 | 18,767 | 89 | 18,005 | 186 | 30,747 | 43 | 14,944 |

Table IV
GENERATOR PARAMETERS

| | $\underline{P}$ (%) | $RD, RU$ (% / h) | $MU, MD$ (h) | $p^{var}$ (RMB / MWh) | $p^{su}$ (RMB / MW) |
|---|---|---|---|---|---|
| coal25 | 54 | 15 | 3 | 350 | 600 |
| coal50 | 54 | 15 | 3 | 308 | 600 |
| coal135 | 54 | 15 | 6 | 287 | 600 |
| coal200 | 54 | 15 | 6 | 263 | 600 |
| coal350 | 54 | 15 | 12 | 238 | 600 |
| coal600 | 54 | 15 | 12 | 209 | 600 |
| cogen25 | 72 | 15 | 3 | 350 | 600 |
| cogen50 | 74 | 15 | 3 | 308 | 600 |
| cogen135 | 74 | 15 | 6 | 287 | 600 |
| cogen200 | 70 | 15 | 6 | 263 | 600 |
| cogen350 | 66 | 15 | 12 | 238 | 600 |
| cogen600 | 60 | 15 | 12 | 209 | 600 |
| hydro | 0 | 30 | - | - | - |

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**Michael R. Davidson** (M'15) received a B.S. in mathematics and physics from Case Western Reserve University in 2008; and an M.S. in technology and policy from the Massachusetts Institute of Technology (MIT) in 2014. He is currently a Ph.D. student in the MIT Institute for Data, Systems, and Society, and research assistant at the MIT Joint Program on the Science and Policy of Global Change. His research focuses on integration of renewable and efficient power systems under different institutional and market contexts.

**J. Ignacio Pérez-Arriaga** MS and PhD (MIT, Electrical Engineering), and Electrical Engineer (Comillas University, Spain). MIT visiting professor since 2008. Professor and Director of the BP Chair on Sustainable Development (Comillas). Director of Energy Training (Florence School of Regulation). Former Commissioner (Spanish Electricity Regulatory Commission and Irish Single Electricity Market Committee). Member of Spanish Engineering Royal Academy. Former member of Board of Appeal of EU Agency for the Coordination of Energy Regulators. Advisor of institutions and governments in more than 35 countries.