ISSN No. 2454 - 1427

CDE
March 2022

Unit Commitment in a Federalized Power Market: A Mixed Integer Programming Approach

Payal Mitra
Email: - payalmitra2@gmail.com
Elsevier, Amsterdam

Soumendu Sarkar
Email:-sarkarsoumendu@gmail.com
Department of Economics,
Delhi School of Economics

Tarun Mehta
Email:-ztarunm004@gmail.com,
Centre for Energy,
Environment and Water,
New Delhi

Atul Kumar
Email:-atulkumar@.mail.jnu.ac.in
School of International Studies,
Jawaharlal Nehru University, New Delhi.

Working Paper No. 323

http://www.cdedse.org/pdf/work323.pdf

Centre for Development Economics
Delhi School of Economics
Delhi- 110007

Unit Commitment in a Federalized Power Market: A Mixed Integer Programming Approach

Payal Mitra * Soumendu Sarkar † Tarun Mehta ‡ Atul Kumar §

Abstract

We study the features of the Indian power system and deconstruct the factors that impede its transition to more optimised market mechanisms. We also present an adaptation of unit commitment from literature, tailored to India's characteristics. Such a model enables India-like power systems to transition to state-of-the-art combinatorial optimisation solution techniques such as Mixed Integer Liner Programming. Further, by simulating the unit commitment problem for the state of Rajasthan with actual data from the year 2015-16, we demonstrate the possibility of significant savings for a central planner in procuring and scheduling adequate power to meet its demands securely.

JEL Classification: C61, Q41, Q42

Keywords: Unit Commitment, Power Markets, Energy, Electricity, Mathematical Programming

*payalmitra2@gmail.com, Elsevier, Amsterdam

†sarkarsoumendu@gmail.com, Department of Economics, Delhi School of Economics, University of Delhi

‡tarunm004@gmail.com, Centre for Energy, Environment and Water, New Delhi

§atulkumar@.mail.jnu.ac.in School of International Studies, Jawaharlal Nehru University, New Delhi. This work is based on Ms. Payal Mitra's master's dissertation at TERI School of Advanced Studies. The Research Assistantship offered by TERI School of Advanced Studies to Ms. Payal Mitra is graciously acknowledged. The support of Manish Mishra in simulating Renewable Energy forecasts for the period of interest is also gratefully acknowledged.

1 Introduction

The stability of a power grid is highly sensitive to imbalances in supply and demand of power. The variability in load (demand), or in power generation (supply) must be instantaneously balanced by changing production, or curtailing/shifting demand in real time. The operations are bound by several technical constraints such as grid transmission congestion, and a range of inflexibilities at power plant level, e.g., unit start-up costs, minimal operating levels, ramping up and down constraints. A power system may be conceived as scheduling generation (alternatively, dispatching load) across heterogeneous stations to optimize some objective function, like minimizing total cost of power production, subject to such constraints. This gives rise to a combinatorial optimization problem in real-time management of the system commonly referred as Unit Commitment Problem (UCP).

Given the importance of UCP in power system security and efficiency, there have been significant advances in research and implementation of dispatch mechanisms in diverse power systems across the world, as well as in commercial optimization solvers available. However, some power systems, such as in India, are still using outdated methods of power dispatch like the Merit Order that are known to be resource inefficient instead of more dynamic trading practices. In 2018, over 85% of India's power transactions were long term purchase agreements that locked up capacity, and encouraged self-scheduling amidst DISCOMs[1] who pursued individual optimisation decisions instead of a global, central objective (Ministry of Power, 2018a). In contrast, several electricity operators such as in the USA - PJM, CAISO, etc - have restructured their power systems to settle a majority if not all of their power transactions through short term or real-time markets, citing better price discovery that supports their objectives of reliable and least-cost generation(Ministry of Power, 2018a).

This paper presents some stylized facts on India-like power systems and analyzes the factors that impede their transition to more optimised market mechanisms. It also presents an adaptation of UCP from literature, tailored to India's characteristics. Such a model enables India-like power systems to transition to state-of-the-art combinatorial optimisation solution techniques such as Mixed Integer Liner Programming. Further, by utilizing the formulated model to solve the UCP for the state of Rajasthan with actual data from the year 2015-16, it demonstrates the significant savings possible for an entity in procuring and scheduling adequate power to meet its demands securely.

At present, India is working to transition towards more dynamically optimised, advanced market based dispatch, with high levels of Renewable Energy integration. The ideas presented in the paper find relevance for different market players in the changing Indian context - may it be operating regulators, transmission, generation, or distribution entities.

The paper is organised as follows - Section 1.1 describes various aspects of the Unit Commitment Problem, Section 1.2 discusses the peculiarities of India-like power sys-

[1] DISCOM, or a Distribution Company is a load-serving entity that acts as an intermediary purchasing and distributing electricity, between generation companies and final consumers.

tems that need to be factored into the UCP formulation, while Section 1.3 presents the proposed UCP model. Section 2 and Section 3 present the related literature and methodology respectively, while Section 4-6.1 present a simulation of the UCP for the state of Rajasthan. Section 7 concludes.

1.1 The Problem of Unit Commitment

Unit Commitment (UC) refers to the schedule of operation across multiple power generating units that meets system demand at all times, while optimising an objective function subject to technical constraints of individual power plants and the grid. Such optimization objectives include minimisation of total generation cost, emissions or some measure of social welfare, or maximisation of profit. In contrast, Economic Dispatch (ED) refers to mechanisms based on economic criteria to determine the order in which generators are selected to provide the next incremental unit of electricity demanded.

The various ED and UC solution methods employed by different power systems vary, depending on the regional power system organisation and philosophy, the nature of markets used (bilateral contracts vs. power exchange markets, different temporal markets, ancillary services), level of technical complexity modeled, and choice of mathematical approach to the constrained optimisation. The power system organisation inhabits the spectrum between central-planner economies and completely deregulated market based power systems.

Several developed countries have restructured their power markets to allow competition to deliver lower prices, better environmental outcomes, and foster innovation (Monast, 2019). In completely deregulated markets, an Independent System Operator (ISO) oversees Security-Constrained UC (SCUC) to ensure that demand is met subject to technical constraints, while optimising a measure of welfare that is a function of bids and offers of market participants (Carrión and Arroyo, 2006). Sophisticated methods of UC have been employed in such restructured power markets to enable better price discovery, as seen in Australia, Ireland and different regional markets of the USA(Ott, 2010). Post the NorthEast power blackout crisis of 2003, several operators of US, such as PJM, adopted computationally efficient Mixed Integer Programming, and real-time dispatch models to schedule sourced power more efficiently(Ott, 2010).

In contrast, some specimen power systems such as India's and Egypt's, employ relatively outdated UC solution mechanisms which do not yield least cost dispatch solutions (Mercados Energy Market India Pvt. Ltd, 2014; Dupont, 2015; Omar et al., 2020). Two highlights of India's suboptimal UC are (1) the choice of Merit Order of Economic dispatch that does not optimise given real-time operating cost functions and constraints of heterogeneous generation units, and (2) A hybrid public monopoly-cum-market power system structure which has price distortions and inefficiencies. These inefficiencies are created by a predominance of long-term bilateral contracts, less reliance on short term or real-time power exchanges, and some degree of centralregulation in pre-allocating centrally owned generation capacity to different recipients.

The next Section discusses the above two factors seen in India-like power systems in greater detail.

1.2 The hybrid and transitioning power structure of India

India is currently in a phase of transition toward greater reliance on market mechanisms and spot power exchanges (Mercados Energy Market India Pvt. Ltd, 2014; Ministry of Power, 2018a). In 2008, the Power Exchange India Limited (PXIL) and the Indian Electricity exchange (IEX) were launched to facilitate trading of power and other derivatives between parties (Mercados Energy Market India Pvt. Ltd, 2014). However, these markets are in their infancy and there still remains heavy reliance on bilateral long term contracts between producer-consumer. In 2018, over 85% of all power transactions in India were in form of long-term PPAs (Ministry of Power, 2018a). Further, there still exists significant government regulation and ownership of assets in the sector.

Public sector firms own significant stake in generation capacity as well as distribution chains, resulting in some features of a vertically integrated public monopoly. Some Indian states have certain generation stations that are wholly dedicated to serving the needs of the same state's distribution utility company (DISCOM), which enables them to self-schedule in silos without considering players in other regions of the larger connected grid or alternative cheaper sources of procurement (Ministry of Power, 2018a; Power System Operation Corporation Ltd, 2018). A tier above, the national generation stations also pre-allocate their capacity to different Indian regions/states. In India, short-term planning and control of power generation is exercised concurrently in each state and is subsequently followed by regional, and then national coordination. We refer to this feature as federal regulation of the power system[2]. Figure 1 depicts the power portfolios of discoms which have a large share of bilateral contracts and Figure 2 depicts this cascading regulation.

When a large amount of generation capacity is locked up and prioritised for dispatch, there is little flexibility in procuring cheaper generation in short term or real-time power exchanges. In fact, recognising the inefficiencies caused by the long term bilateral contracting structure by way of localised and bilateral dispatch decisions, POSOCO[3] has proposed National level SCED (Security Constrained Economic Dispatch) that fine-tunes real-time dispatch globally (Power System Operation Corporation Ltd, 2018).

Real-time scheduling of power generation is a staggered and iterative process, with generation companies (GENCOs) and consumers (DISCOMs) submitting their supply availability and demand respectively, a day ahead of the transaction. These unit level schedules are then aggregated, coordinated, and revised (to account for any unexpected changes) up to real time by national and regional load dispatch centres. Currently long-term PPAs between producer-consumer are given priority in scheduling at any time-slot, even if cheaper power sources are available. After scheduling the PPA quota, the dispatch

[2] In India, electricity is in the Concurrent list of the constitution, which empowers both the state and central government to legislate on this matter

[3] Power System Operation Corporation of India - https://fin.posoco.in/

algorithm ”Merit Order”, ranks plants by a single value of Full-Foad Average Production Cost (FLAPC), and decommits generators in sequence of the next highest FLAPC, until power is balanced (and vice-versa when additional units are to be committed during excess demand) (Sen and Kothari, 1998; Yamin, 2004). Merit Order does not consider the non-linear production costs or operational inter-temporal constraints faced by each generating unit. The marginal production cost for online units is a function of output level of the unit (often approximated as quadratic or cubic functions (Sönmez, 2013)), and thus replacing the function with a single average value distorts cost signals. Additionally, a real power system has a heterogeneous technology mix, with different plants having their own operating constraints and costs. Thus any combinatorial optimisation problem should account for constraints at both levels - at unit level, and across different units.It has been long established as suboptimal (Sen and Kothari, 1998; Yamin, 2004; Delarue and D'haeseleer, 2007).

With a global thrust towards cleaner technology, the question of optimal scheduling of a mixed fleet of conventional and Renewable Energy (RE) based generators has become undeniably pertinent (Abujarad et al., 2017). India has setambitious targets for 450 GW of RE based generation capacity from wind and solar sources by 2030(Ministry of Power, 2019 [Online].). RE generation is characterized by high localization, variability, intermittency and uncertainty (Abujarad et al., 2017). The integration of fluctuating RE with the power grid imposes several costs on the power system as it compels conventional power generators to operate at economically and technically inefficient levels, and face flexibility costs in form of more frequent ramps, startups and shutdowns in order to avoid curtailment of RE (Abujarad et al., 2017; Huber et al., 2014; Bistline, 2017). In this context, the use of appropriate UC methods can help power systems access flexible generation sources, and thus become more resilient to VRE and reduce their curtailment. This paper takes into consideration the influence of such RE obligations alongside more conventional sources.

The recent impetus provided by the central regulators in India to restructure the power sector with market interventions for economic dispatch makes the requirement for more modernised UC solution methods even more relevant. Some public initiatives include the launch of the MERIT app in 2017 to promote more transparency about marginal variable cost of electricity dispatch to enable more informed procurement decisions (Ministry of Power, 2017) [4], and an April 2018 directive to encourage flexibility in scheduling of thermal stations in a bid to reduce emissions, and accommodate for RE integration into the grid (Ministry of Power, 2018b). Recently the central electricity authorities proposed transition plans to phase out legacy operations in favour of competitive market based economic dispatch with more efficient real-time scheduling and flexibility that attains lower localised, as well as system wide costs. (Ministry of Power, 2018a)

[4] Quoting the notification (Ministry of Power, 2017) by the Ministry of Power, India, the MERIT app would promote transparent information dissemination pertaining to marginal variable cost and source wise purchase of electricity and Optimization of the power procurement costs

1.3 Proposed UCP adaptation

Mathematically, literature has framed UCP as a combinatorial constrained optimisation problem. However to be applicable in India-like systems, present state-of-the-art UCP formulations need to be adapted to reflect the peculiarities described above. Identifying that such a model is not readily available, this work attempts to address the gap.

This paper puts forth an adapted SCUC model for a federal, partially regulated power system akin to India, as an Mixed Integer Programming (MIP) problem. Its main contributions are:

- To examine the characteristics of power systems like India with archaic, suboptimal Unit Commitment methods, and suggest how to transpose them to more advanced UC optimisation techniques in both state regulated or free-market settings;
- To model the UCP scenario of a state/regional planner, with partial reliance on market mechanisms as an MIP problem. It reflects the objective to securely source power from a heterogeneous production units to meet the state?s demand at the least procurement cost. The model incorporates the presence of RE and unit level technical constraints;
- To demonstrate the applicability and merits of the proposed UCP-MIP solution in the Indian context. By simulating the UCP for the State of Rajasthan with real data, this paper illustrates the potential gains of switching from the merit order to the MIP formulation in the presence of RE in the generation mix.

The market restructuring proposed will require various players in the power system (GENCOs, DISCOMs, market regulators, transmission and grid system operators) to forecast and solve more sophisticated UC formulations that respect unit-level and grid level constraints in real time.

Thus, while the proposed model emulates the perspective of a state planner, the model can be adapted to completely market-based dispatch as proposed by the Indian power authorities(Ministry of Power, 2018a). For instance, the centralised ISO in deregulated power markets, who optimises a function of the difference between the market participants' bids and offers can mimic the SCUC of a central planner minimising total operation cost (Yamin, 2004; Carrión and Arroyo, 2006; Van den Bergh et al., 2014).

Further, in a power-exchange framework, the UCP formulation in this work remains relevant for large GENCOs with multiple units, to help in the discovery of their price bids. In this setting, instead of the state planner who owns vertical operations in the market and minimises social welfare, the objective can be recast as profit maximisation for the GENCO which determines its own sell-bid vs offer curve using the same MILP construction, albeit without bothering about system-level requirements such as adequacy of reserves or global balancing of power.

Figure 1: Some Differences in India-like Power Systems

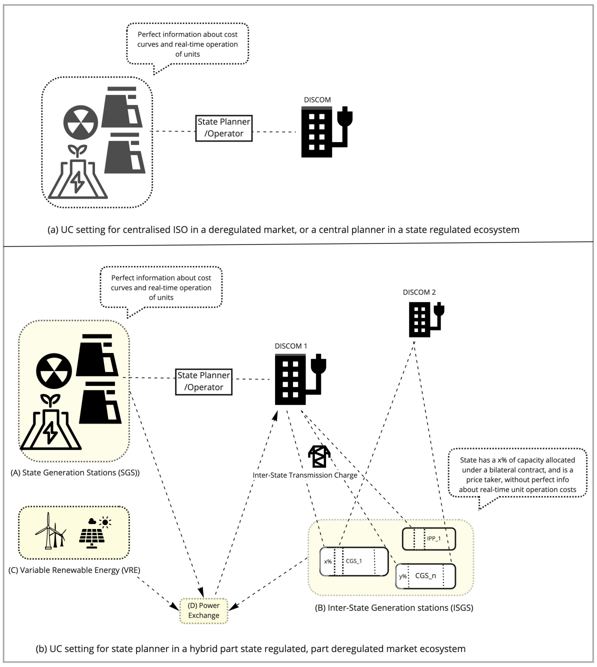
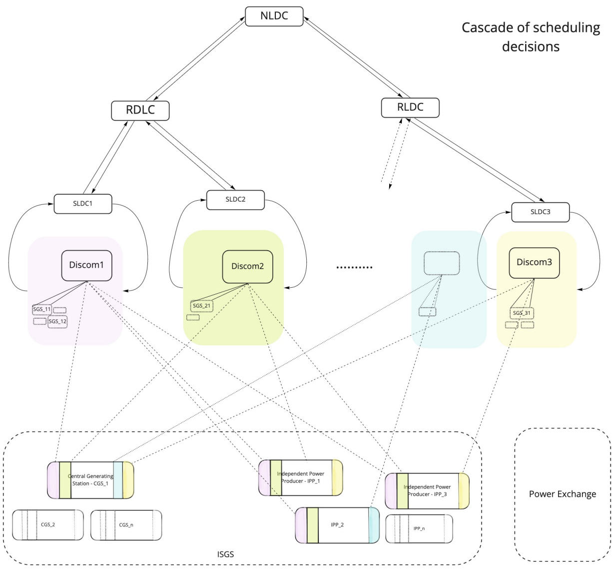


Figure 2: Indian Power system scheduling



2 Literature

Literature on UC has mostly focused on developing complex theoretical models that mimic reality, as well as on conducting simulations demonstrating proposed advantages of advanced UC mechanisms in real-life power systems. It has attempted to accommodate heterogeneity of technology, technical and regulatory constraints, grid integration of the highly variable and uncertain RES generation (Zhao et al., 2013; Ummels et al., 2007), power transmission constraints (Lee et al., 2013), effect of storage facilities (Cebulla and Fichter, 2017; Nazari et al., 2010) and UC in microgrids (Hawkes and Leach, 2009; Zhao et al., 2013).

However, these threads of UC literature have been primarily focused on either of the two ends of power sector organisational structure: (a) A Centralised authority that controls all power resources in the country and is solely responsible for all operational decisions, and (b) a completely deregulated power sector, where each GENCO attempts to maximise profit, while an ISO usually performs regulatory functions to drive desired overall system behaviour. The corresponding UC models for the above are (a) Security Constrained Unit Commitment (SCUC), and (b) Price Based Unit Commitment (PBUC).

In an SCUC, a central planner attempts to securely meet power requirements at minimum system-wide cost of generation (Muckstadt and Koenig, 1977; Carrión and Arroyo, 2006; Van den Bergh et al., 2014). This implicitly assumes that the regulator does not exhibit price-taking behaviour, and has perfect knowledge of the technical and operational costs of each generator. SCUC can also be used as a proxy to determine market outcomes for an Independent System Operator (ISO) who clears the market bids to maximize some notion of social welfare (Yamin, 2004; Carrión and Arroyo, 2006; Van den Bergh et al., 2014). In contrast, Price-Based Unit Commitment (PBUC) is is relevant to individual profit-seeking power generation companies without an obligation to serve demand who can decide their supply at prevailing market prices. It is also This form of UC is followed in electricity markets of New England Power Pool, Australia, California Market (Yamin, 2004; Van den Bergh et al., 2014; Dlakic, 2010).

Such formulations in related literature do not directly apply to India-like power systems which have peculiarities such as a hybrid state-regulated cum fledging market ecosystem as described in Section 1.2. Our work recasts the UCP in such atypical power systems as an extension of the SCUC, as detailed in sections 3.1 and 3.

Primitive methods, such as Merit Order/Priority Order of Dispatch, rank different generating units on basis of a single averaged value of production cost per unit power. The suboptimality of the Merit Order method of Dispatch has been discussed by Sen and Kothari (1998), Yamin (2004), and in Section 1.2.

A separate strain of research has worked on developing more sophisticated algorithms for solving the UCP, such as Dynamic Programming (DP), Lagrangian Relaxation (LR), Mixed Integer Programming (MIP), Genetic Algorithms (Yamin, 2004; Delarue and D'haeseleer, 2007; Muckstadt and Koenig, 1977; Cheng et al., 2000; Wood et al., 2013; Snyder et al., 1987; Selvakumar et al., 2016).

However, DP and LR have been criticized for various shortcomings such as the inability to handle large-scale problems, or no guaranteed feasibility and optimality of its solutions (Yamin, 2004). MIP is considered superior amongst the aforementioned methods (Carrión and Arroyo, 2006; Van den Bergh et al., 2014). MIP is a constrained optimization problem in which the objective variables include both binary (such as variables denoting unit on/off condition), and continuous non-negative variables (such as variables denoting output power by each unit in each time period). MIP has been used widely due to recent advancements in commercial MIP solvers that assure convergence and feasibility, provided a feasible solution exists (Delarue and D'haeseleer, 2007; Carrión and Arroyo, 2006; Van den Bergh et al., 2014). This work builds upon past works such as in (Carrión and Arroyo, 2006) and models the UCP as an MIP problem.

A recent strand of literature focuses on UCP with the presence of RE such as wind and solar energy in the power system, and models the impact of RE forecasting errors (Abujarad et al., 2017). Existing research shows meteorological data can be used to simulate hourly RE generation (Richardson and Harvey, 2015; Prasad et al., 2017). This paper focuses on modeling the UC decisions of real-world systems with RE in concept, but does not explore the uncertainty and stochasticity of RES.

3 Methodology

3.1 The Indian context

This paper tailors SCUC to better reflect the features of power systems that lie between the two ends of the spectrum of a centrally planned economy, and a completely deregulated market.

In states of India, both the load serving entities (DISCOMS) and a majority of producers are government entities. We make the simplifying assumptions that (1) the state's intent when procuring and dispatching power is to minimise operation cost, and not profit maximisation; (2) The buyer-seller role of the state is represented as that of a central planner who minimises system-wide power procurement cost from available generation portfolio, instead of the power generation cost.

In order to model the unit-level and grid level constraints that affect UC in real time operations, we formulate the benevolent state-planner's SCUC in an Mixed-Integer Linear Programming setting. This model is presented in Section 3.2.

3.2 Model Description

Our computational model of SCUC has the following features:

1. Federal regulation;
2. Presence of both private and public-sector players;
3. Heterogeneity of technological parameter values and operational constraints across individual generation units;
4. Inclusion of grid-integrated RE into the energy mix as a deterministic component;

5. Several stylized facts from the Indian power sector;
6. Separate provision for Inter-state transmission charges and losses.

The model takes note of non-linearity and discontinuity in production costs by use of a piece-wise linear production cost function for each individual unit. It accounts for unit-level startup costs, shut down costs, minimum downtime, minimum uptime, minimum operating output levels, ramping constraints, and logical constraints on unit status.

3.2.1 Optimisation objective

As mentioned in subsection 3.1, the state planner in the model is assumed to be minimising system-wide power procurement cost subject to grid and unit level constraints. The procurement cost includes both cost of power production, as well as operational costs towards transmission or maintaining extra reserve capacity. See subsection 3.3.

3.2.2 Constraints

Three main classes of constraints have been considered: (1) overarching demand-supply constraint in *every* time period, (2) grid-level constraints such as technical feasibility and adequacy of power reserves, and (3) individual generation unit-level operational constraints.

3.2.3 Portfolio of Generation stations

The state planner has three main sources in its portfolio mix, viz., (a) state-generating stations (SGS), wholly dedicated to the state, (b) bilateral contracts with inter-state generating stations and (c) RE. For (a), the state planner has complete information on cost curves and operational processes. For (b), the planner is a price-taker, and is only aware of averaged costs reported by individual generating companies.

Category (a) - State-Controlled Generators These generating units (other than RE based units) are wholly dedicated to the jurisdiction of the state, and can be considered as entirely under the planner's control. The planner is privy to the technical parameters and nonlinear cost curves of the in-state generators. Assuming power prices (ignoring transmission costs) are set by the planner at true generating cost without any profit margin, the planner's objective of minimising the cost of in-state power procurement and scheduling is identical to minimising total in-state system generation costs.

Category (b) - Inter-State-Controlled Generators (ISGS) To fulfil excess demand obligations the Planner may source a proportion of its power requirement from external Inter-State generation resources, subject to transmission constraints. These may be owned by the Central Generating Stations (CGS) or Independent Private Producers

(IPPs). The planner enters into long-term bilateral PPAs with different ISGS, where the state is a beneficiary and is entitled to a share in the ISGS's capacity at pre-decided Energy Charge Rates. The Planner cannot ascertain the total load faced by ISGS due to other beneficiaries. Thus, the State becomes a price taker and is more focused on minimizing purchasing cost as a buyer, regardless of the overall efficient levels of operation or generation cost of the ISGS unit. The planner must also consider Inter-State Transmission System (ISTS) Usage Costs, to accurately account for the cost of transmission and to enable commensurate comparison with in-state generation costs while solving the UCP. In this model, this category does not include RE based units.

Category (c) - Renewable Energy Sources and Nuclear We assume that the state is obligated to utilize all power generated from renewable and nuclear energy without any curtailment prior to using other conventional sources under Categories (a) and (b).

Given this portfolio, the state must determine the UC solution. First, the net load is obtained for the planning period after deducting the obligated RE generation and nuclear (category (c)) from the state's forecasted demand. Subsequently, the State Planner must determine the cost optimal schedule of conventional generators from categories (a) and (b).

3.3 Mathematical Model

Throughout, the binary variables, viz. v_{jt}, y_{jt} and z_{jt}, denote unit j's commitment (on/off) status, the start-up and shut-down decisions at time period t respectively.

3.3.1 Objective Function

The objective function of UCP for the State Planner is:

$$Min\left(\sum_{t\in T}\sum_{j\in J_a} f_{ajt} + \sum_{t\in T}\sum_{j\in J_b} f_{bjt}\right) \tag{1}$$

where variables f_{ajt} and f_{bjt} are the generation costs of operating unit $j \in J_a$ and $j \in J_b$ respectively, at period t for output level p_{jt}.

The first term in the objective function captures all costs related to operation of the state-owned generators of category (a). Since the planner is assumed to own these plants, it can determine the cost minimising schedule of units to be operated. The second term represents the power purchasing costs from external ISGS (generator category (b)), over which Planner has no jurisdiction beyond its pre-allocated share at pre-fixed energy tariffs.

The generation cost comprises several elements discussed below. The cost of generation from RE and nuclear sources has not been considered in the objective function due to the assumption that RE and nuclear power must not be curtailed. Thus, all possible supply from these sources is obligatorily utilised and deducted from the power demand. The residual demand is served from an optimized unit commitment among generators of category (a) and (b) Finally, the cost of power production from RE and nuclear is added back to the final optimized generation costs to obtain the total system generation costs.

a. Generation cost of state owned generators ($\sum_{t\in T}\sum_{j\in J_a} f_{ajt}$) The generation cost f_{ajt} of an individual generating unit is given by:

$$f_{ajt} = cp_{jt} + cu_{jt} + cs_{jt}; \forall j \in J_a, \forall t \in T \tag{2}$$

where cp_{jt} is production cost, cu_{jt} is the startup cost, and cs_{jt} is the shutdown cost.

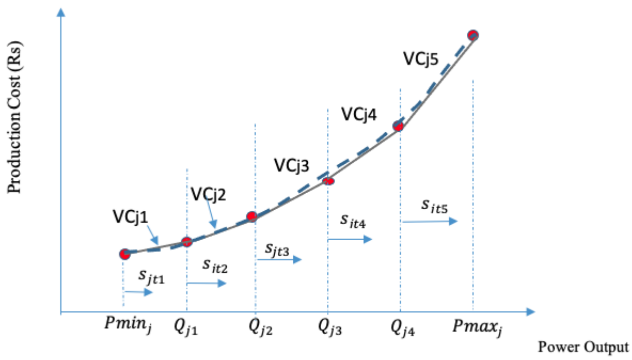
- Production Cost cp_{jt}

The production cost (cp_{jt}) curve of a generating unit is non-linear in its output, often assumed to be a quadratic function of power output.

$$cp_{jt} = v_{jt} \cdot a_j + b_j \cdot p_{jt} + c_j \cdot p_{jt}^2 \tag{3}$$

In the above equation, a_j, b_j and c_j are polynomial coefficients, while v_{jt} is the unit commitment status decision variable described previously. For practical purposes, the quadratic curve for cp_{jt} can be approximated by a set of NL_j piece-wise linear segments, as depicted in Figure 3. The start and end point of each line segment stepis marked by $Q_{(j,step-1)}$ and $Q_{(j,step)}$. The marginal cost of production in each step ($VC_{(j,step)}$), is the constant slope of the corresponding line segment.

Figure 3: Piece-wise linear approximation of production cost



The power output produced by the unit can be written as the sum of the variables $s_{(j,t,step)}$ that denote how much power output is generated in the step segment. The term $s_{(j,t,step)}$ can take a non-zero value for a step, only if the power output has exceeded the preceding power steps. Further, if the unit is online, it cannot produce below the minimum stable power output P_{min_j}.

$$p_{jt} = P_{min_j} \cdot v_{jt} + \sum_{step=1}^{NL_j} s_{j,t,step}; \forall j \in J, \forall t \in T \tag{4}$$

$$cp_{jt} = A_j \cdot v_{jt} + \sum_{step=1}^{NL_j} (VC_{j,step} \cdot s_{j,t,step}); \forall j \in J, \forall t \in T \tag{5}$$

$$A_{jt} = a_j + b_j \cdot P_{min_j} + c_j \cdot P_{min_j}^2; \forall j \in J \tag{6}$$

where, A_j is the minimum production cost incurred by unit j, when $p_{jt} = P_{min_j}$.

Further,$VC_{j,step}$ is the marginal cost, or variable cost of producing an additional unit of power in the step segment of the piece-wise linear production cost curve. It is equal to the slope of the corresponding step line segment, as defined below.

$$VC_{j,step} = \frac{CostofProducingQ_{j,step} - CostofproducingQ_{j,step-1}}{Q_{j,step} - Qj, step - 1}; \forall step > 1 \tag{7}$$

$$VC_{j,1} = \frac{CostofProducingT_{j,1} - CostofproducingP_{min_j}}{T_{j,1} - P_{min_j}}; step = 1 \tag{8}$$

- Shutdown Cost cs_{jt}

Shut down cost (cs_{jt}) defines the cost incurred upon shutting down the unit j in time period t. The term z_{jt} is the binary shutdown decision variable; taking the value 1 if a previously running unit j has been made to shut down in period t.

$$cs_{jt} = shut\_down\_cost_j \cdot z_{jt} \tag{9}$$

- Startup Cost cu_{jt}

Start-up cost is incurred upon starting up unit j in time period t; it is a function of how long the unit has remained offline. A typical form is the exponential start-up cost curve. For convenience, we consider only two kinds of start-up costs, i.e., a hot start cost (hc_j), and a cold start cost (cc_j), dependent on the cost of input energy required for a startup. Here, t_{off_jt} denotes the number of periods that the unit j has been offline prior to period t. The variable t_{cold_j} denotes the number of periods in excess of the minimum down-time DT_j, beyond which, if a unit remains offline, it must incur a cold start whenever switched on. Conversely, if $t_{off_jt} > \phi_j$, that is, a unit has been offline for more than ϕ_j time periods ($\phi_j = DT_j + t_{cold_j}$), it requires a 'cold start' to be brought online. If it remains offline for a shorter period than ϕ_j (i.e., $t_{off_jt} \leq \phi_j$) it requires a hot start, subject to minimum downtime constraints (Equations 27-29). The Start-up costs are defined as:

$$cu_{jt} = [hc_j \cdot q_{jt} + cc_J \times (1 - q_{jt})] \cdot (1 - c_{j,t-1}) \cdot v_{jt}; \forall j \in J, \forall t \in T \tag{10}$$

To differentiate between the two types of start costs, based on $t_{off_j t}$, we introduce two more variables, viz. a binary variable q_{jt}, and a discrete variable, x_{jt}.

$$x_{jt} = \sum_{n=1}^{\phi_j} v_{j,t-n} \tag{11}$$

Equation 11 implies that x_{jt} is the sum of the unit status variables in the ϕ_j periods immediately preceding the time period t. When q_{jt} takes the value of unity, it indicates the applicability of a hot start, while a value of zero indicates a cold start. The manner in which these variables reflect the decision of the start-up type, is presented in Table 1 below:

Table 1: Combination Space for x_{jt} and q_{jt}

S.No.	x_{jt}	q_{jt}
1	>0	$=1$
2	$=0$	$=0$
3	>0	$=0$
4	$=0$	$=1$

Equations 12 and 13 are constructed to account for two kinds of start-ups, and to ascertain whether a hot or a cold start would be required for unit j in period t.

$$q_{jt} - x_{jt} <= 0; \forall j \in J_a, \forall t \in T \tag{12}$$

$$q_{jt} \cdot [q_{jt} + x_{jt}] >= x_{jt}; \forall j \in J_a, \forall t \in T \tag{13}$$

b. Electricity Procurement cost from ISGS ($\sum_{t \in T} \sum_{j \in J_b} f_{bjt}$) The cost of purchasing electricity from ISGS, comprises energy charges and fixed capacity charges (Ministry of Power, 2016). The Energy charges for period t are paid in proportion to the amount of power actually drawn in that period. The fixed capacity charges are paid annually or monthly on the share of the unit's capacity allocated to the state, regardless of whether the state actually utilises its entire share at any point in time. Hence these charges can be regarded as sunk cost which does not enter the objective function.

Inter-state transmission system (ISTS) charge Additionally, we include the cost of power purchased from ISGS to account for the actual cost faced by the procuring State Planner in bringing this power to the state's boundary. In this paper, the ISTS tariff and losses have been modelled on the methodology followed in India [20,21]. The energy charges are paid to the generator for power scheduled before losses (p_{jt}), while ISTS charges are paid loss-adjusted-power, (on $p_{jt} \cdot (1 - loss_{istsjt)})$. The term e_jŹ is the energy charge per unit power from generator $j \in J_b$; the term τ is the fixed ISTS tariff per MWh; the term $loss_{istsjt}$ is the proportion of power lost due to inter-state transmission.

The final procurement costs for ISGS power can be expressed as:

$$\sum_{j \in J_b} [e_{jt} \cdot p_{jt} + \tau \cdot p_{j,t} \cdot (1 - loss_{istsjt})] \tag{14}$$

c. Final objective function Thus, the final Objective function to be minimized is a combination of the costs of producing power from state owned generating units and ISGS:

$$Min \sum_{t \in T} [\sum_{j \in J_a} (cp_{jt} + cu_{jt} + cs_{jt}) + \sum_{j' \in J_b} e_{j't} \cdot p_{j',t} \cdot (1 + loss_{j't}) + \tau \cdot p_{j't}] \tag{15}$$

3.3.2 Constraints

a. Demand-Supply Constraint In every period, power sourced from in-state generators, ISGS as well as renewable sources must equal the power demand after accounting for the inter-state ($loss_{ists}$) and intra-state ($loss_{intrastate}$)) transmission losses. D_t is the power demanded in time period t before accounting for transmission losses.

$$\sum_{j \in J_a} p_{jt} + \sum_{j \in J_b} p_{jt} \cdot (1 - loss_{ists}) + RE_t = D_t \cdot (1 + loss_{intrastate}); \forall t \in T \tag{16}$$

b. Adequacy of reserves constraint The aggregate sum of maximum power output potentially producible by each generating unit (by ramping up production) in each time period t, ($\sum_{j \in J} p_{upperjt}$), is required to equal the loss-adjusted power demand $D_t \cdot (1 + loss_{intrastate})$, plus a reserve margin (R_t).

$$\sum_{j \in J} p_{upperjt} = D_t \cdot (1 + loss) + R_t; \forall t \in T \tag{17}$$

c. Technical Feasibility Constraints

$$p_{jt} \in \prod_{jt} \forall j \in J; \forall t \in T \tag{18}$$

The output power p_{jt} should belong to the feasible production set of the generator j, in the particular time period t, i.e., $\prod_{jt}$. Various inter-temporal and technical constraints faced by generating units which are described below.

Individual unit constraints: Defining feasible production set $\prod_{jt} (\forall j \in J; \forall t \in T)$ These include Thermal constraints and logical constraints on unit commitment status variables. The former deals with technical output, start/stop of a generation unit, while the latter declares nonsensical state values as illegal - for instance, no valid UC solution can allocate a particular unit both a positive startup and a shutdown decision in the same period.

Thermal Constraints

- Stable Operational limits

Each thermal generator has a minimum stable power output level, $Pmin_j$, below which it can not produce, and must shut off. $p_{upperjt}$ is the maximum a unit can potentially produce in a given period, subject to previous period's output and ramping rates. The volume $p_{upperjt}$ is capped by the $Pmax_j$:

$$Pmin_j \cdot v_{jt} \leq p_{jt} \leq p_{upperjt} \leq v_{jt} \cdot Pmax_j \tag{19}$$

- Ramp-up and ramp-down limits

These refer to the amount by which the production of a thermal generation unit can be increased (Ramp Up Limit RU_j) or decreased (Ramp Down Limit RD_j) in a single time period k respectively.

$$P_{upperjt} \leq p_{j,t-1} + RU_j \cdot v_{j,t-1} + Pmax_j \cdot (1 - v_{j,t}) \tag{20}$$

$$p_{j,t-1} - p_{jt} \leq RD_j \cdot v_{jt} + Pmax_j \cdot (1 - v_{j,t-1}) \tag{21}$$

- Limits on a generator's power outputs

Equations 22 and 23 describe the behavior of the segmented output variables $s_{j,k,step}$ in each *step* (Carrión and Arroyo, 2006). By construction there can be no power output recorded in a particular step ($step > 1$), unless the power output has, in sequence, exceeded the step prior to it. This sequential manner of allotting power to any segmented interval has been captured by the variable $r_{j,step}$. It is a binary variable indicating whether power output p_{jt} has exceeded the segment *step* of the power range. $Q_{j,step}$ marks the maximum power producible at the end of each step.

$$(Q_{j,1} - Pmin_j] \cdot r_{j,1} \leq s_{j,t,1} \leq (Q_{j,1} - Pmin_j)) \cdot v_{jt} \tag{22}$$

$$(Q_{j,step} - Q_{j,step-1}] \cdot r_{j,step} \leq s_{j,t,step} \leq (Q_{j,step} - Q_{j,step-1})) \tag{23}$$

- Minimum up-time (MUT) constraints

A unit has to remain online for a certain number of time periods, immediately after it has been started up, before it can be shut down again. This is referred to as the minimum up-time (MUT) of a unit (Equations 24- 26) (Carrión and Arroyo, 2006).

$$\sum_{t=1}^{G_j}(1 - v_{jt}) = 0; \forall j \in J_a \tag{24}$$

$$\sum_{n=t}^{t+UT_j-1} v_{jn} \geq UT_j \cdot (v_{jt} - v_{j,t-1}); \forall j \in J_a; \forall t \in G_j + 1, ..., \theta - UT_j + 1 \tag{25}$$

$$\sum_{n=t}^{\theta}[v_{jn} - (v_{jt} - v_{j,t-1}) \geq 0; \forall j \in J_a; \forall t \in \theta - UT_j + 2, ..., \theta \tag{26}$$

where UT_j is the MUT for unit j, G_j is the number of time periods the unit must necessarily remain online from the start of the first period.

If the time interval for which a unit has been online immediately prior to the start of planning horizon is less than UT_j, then the unit must obligatorily stay online for the next consecutive G_j time periods. If not, then $G_j = 0$.

- Minimum down-time (MDT) constraints

A unit has to remain offline for a certain number of time periods, immediately after it has been shut down, before it can be started up again. This is referred to as the minimum down-time (MDT) of a unit. Here, if a unit has been offline for a certain number of periods immediately prior to the start of the planning horizon, then it must necessarily remain offline for the first consecutive L_j periods before it can be started up again. DT_j denotes the MDT of unit j (Carrión and Arroyo, 2006).

$$\sum_{t=1}^{L_j} v_{jt} = 0; \forall j \in J_a \tag{27}$$

$$\sum_{n=t}^{k+DT_j-1} (1 - v_{jn}) \geq DT_j \cdot (v_{j,t-1} - v_{jt}); \forall j \in J_a; \forall t \in L_j + 1, ..., \theta - DT_j + 1 \tag{28}$$

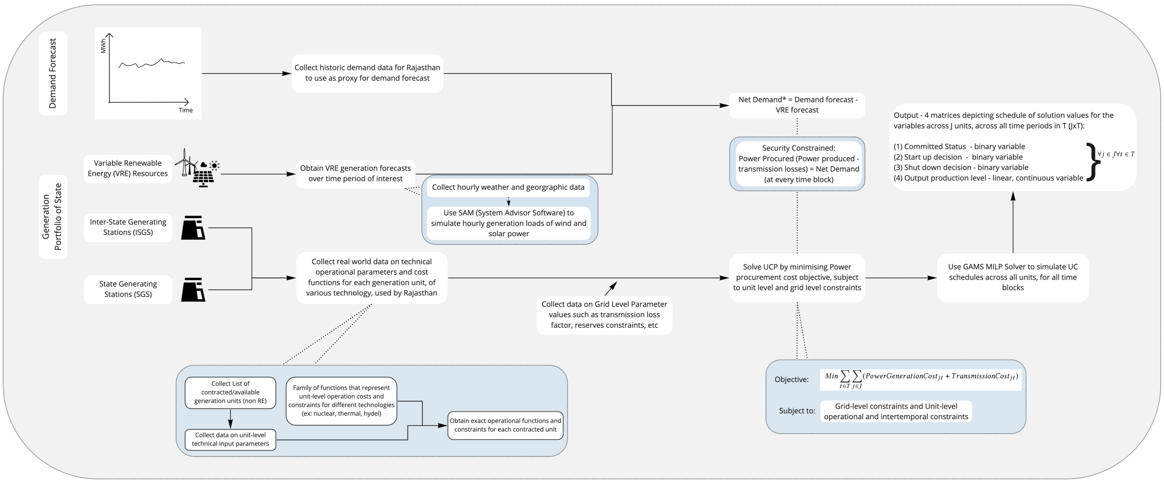
$$\sum_{n=t}^{\theta}[1 - v_{jn} - (v_{j,t-1} - v_{jt})] \geq 0; \forall j \in J_a; \forall t \in \theta - DT_j + 2, ..., \theta \tag{29}$$

Logical constraints on unit commitment status variables, i.e., y_{jt}, v_{jt} and z_{jt}
Equation 30 rules out inconsistent cases such as simultaneously having an offline unit ($v_{jt} = 0$), and a positive start-up decision ($y_{jt} = 1$). Further, if the unit has received a shut-down decision in t, ($z_{jt} = 1$), then 30 ensures consistency by ensuring that the unit was previously online in $t - 1$ (i.e., $v_{j,t-1} = 1$), so that it can be de-committed in period t (i.e., $v_{jt} = 0$). Equation 31 imposes the constraint that unit j cannot receive the instruction to be both started up ($y_{jt} = 1$) and shut down ($z_{jt} = 1$) simultaneously in period t.

$$y_{jt} - z_{jt} = v_{jt} - v_{j,t-1}; \forall j \in J_a; \forall t \in T \tag{30}$$

$$y_{jt} + z_{jt} \leq 1; \forall j \in J_a; \forall t \in T \tag{31}$$

Figure 4: Schematic for workflow to simulate monthly UCP-MIP model for Rajasthan for $2015 - 2016$



4 Data and Assumptions

The model developed was used to simulate the UCP for the Indian state of Rajasthan. The schematic of workflow followed can be viewed in Figure 4. To keep the problem tractable, we make the simplifying assumption that the state's power system consists of a single node to which both the demand, as well as the state-owned category (a) units are attached. The category (b) ISGS are connected to a second node, outside the state's boundary, via ISTS. However, in reality, the power network is a very complex multi-node system.

The work uses most recent historic data as a proxy to the forecast demand facing a state. In our retrospective modelling, the 2015-16 forecast for aggregate state-level hourly demand profile was thus considered to be equal to the historic data from the same period, obtained directly from the Rajasthan State Load Dispatch Centre (SLDC) upon request. Reserve Margin was fixed at 5% of demand in every time period (Ministry of Power, 2005)

Generation unit specific data such as Rajasthan's pre-allocated shares in the installed capacity of ISGS, and fixed and energy tariffs for all generating units (renewable and conventional), were obtained from the Final Petition for Tariff Determination of Rajasthan Discoms (Rajasthan Electricity Regulatory Commission, 2016). Wherever available, the official Annual Revenue Requirement reports were used for individual generating stations.

While for Nuclear Power plants, the tariffs published by the Central Electricity Authority (CEA) for 2015-16 were considered (Central Electricity Authority (CEA), 2013). Hydro-electric plants were assumed to have no variable energy costs and 100% availability. Technical parameters, such as heat rate degradation with different unit-loading levels, ramping rates, minimum uptime/ downtime, intra-state transmission losses, and inter-state transmission system losses and usage charges, were taken from government sources (Central Electricity Authority (CEA), 2016; Rajasthan Rajya Vidyut Prasaran Nigam Limited, 2017; Power System Operation Corporation (POSOCO), 2016; Central Electricity Regulatory Commission (CERC), 2014).

Power was assumed to be procured by the planner from category (a) state-dedicated plants (before distribution) at a price equal to the cost of on-site generation. Only long-run bilateral contracts (PPAs) between the ISGS and the state have been considered to avoid the complications of short-term and spot transactions of power.

For wind energy generation, hourly profile was developed using district wise hourly wind velocity profile and assuming turbine units of 2 MW, with 100m hub height and 100m diameter. The simulation of highly resolved spatial and temporal time series data on wind speed was extracted from National Solar Resource Database (NSRD). Wind speed at the height of 20m has been taken with an hourly resolution, for the different districts of Rajasthan. The wind speed at the height of 100m has been obtained using wind gradient formula:

$$V_h = V_r \cdot \left(\frac{h}{r}\right)^2 \tag{32}$$

where v_r is wind velocity (m/sec) at reference height above surface, v_h is wind velocity (m/sec) at h meter height, α is Hellmann exponent (taken as 0.34 for Neutral air above human inhabited areas (Kaltschmitt et al., 2007)).

In order to model solar-energy based generation profiles, the hourly solar profile per district in Rajasthan was combined with the predicted output of a solar PV plant, as modeled by simulation software, System Advisor Model (SAM). The thus simulated solar generation profile was calculated using SAM, by inputting the hourly Gross Horizontal Irradiance (GHI) and temperature for different districts of Rajasthan (National Renewable Energy Laboratory, 2017b). The Indian Solar Resource Data for the year 2014, provided by the US National Renewable Energy Laboratory (NREL) is used for GHI (National Renewable Energy Laboratory, 2017a).

The model has scaled up demand by a factor equal to the proportion of intra-state transmission losses in order to accurately account for the power generation required to serve the demand post transmission losses. However, the model has not considered any intra-state transmission costs. Unconstrained transmission capacity has been assumed to avoid the complications of transmission congestion which would otherwise require detailed power flow analysis.

All generating units are assumed to have unconstrained fuel supply. We acknowledge that RE generation is variable and uncertain and could receive a stochastic treatment.

However, our model is deterministic in nature.

The shut-down costs have been initialised to an arbitrary small value while demonstrating the use case of Rajasthan due to data limitations.

5 Resources for Model Deployment

The model formulation of MILP-UCP was adapted into an algorithm which was implemented using GAMS language and solved using CPLEX solvers, on the Intel Processor Core i7, with RAM 8GB GAMS Development Corporation (2017); IBM (????). Model was successfully employed and tested numerically for the state of Rajasthan, for each of the 12 months of the year 2015-16. It is worthwhile to mention that, although the model is equipped to handle finer time blocks of 15-minute intervals or less, we have utilized hourly load profiles owing to data accessibility.

6 Results and Analysis

The results obtained from our formulated state-planner UCP model, using a constrained cost-optimization, consist of the following output:

1. An hourly schedule of unit commitment status (online/offline), start-up, and shut-down decisions (v_{jt},y_{jt} and z_{jt} respectively, $\forall$ j,t) for each state owned and ISGS unit, for each hour in the corresponding month.

2. An hourly schedule of power output generated (or procured) by each state owned and ISGS unit, for each hour in the corresponding month.

3. A segmented power output schedule which depicted, for each of the state-owned units, the quantum of power that was produced in each step interval of a generator's production range (corresponding to segments in its piece-wise linear production cost curve), that is, the family of variables $s_{j,t,step}$

4. Optimal total system power generation(cum-procurement) cost borne by state planner for meeting the monthly demand and reserve requirements.

5. Optimal hourly weighted cost of procuring power from all available sources (all three categories of units), as faced by consumer/planner, for each hour in the corresponding month. This cost includes both fixed and energy charges.

In view of the high levels of curtailment of solar and wind electricity generation in India, the results have been analysed for following two distinct scenarios:

1. **Scenario A:** With zero curtailment of grid-integrated RE based power.

2. **Scenario B:** With curtailment of grid-integrated RE as per simulated results and actual utilization level (in percentage of total generation potential) in 2015-16.

Results for obtained optimal daily energy mix for two select days; 1^{st} July 2015 (during monsoon and heavy wind energy potential), and 1^{st} January 2016 (one of the coldest months resulting in highest power demands) for Scenarios A and B have been illustrated in Figures 5 and 6 respectively.

1. Optimal Daily Energy Mix under MIP-based UCP model for Rajasthan:

Figure 5: Optimal Daily Energy mix under Scenario A: Zero RE curtailment

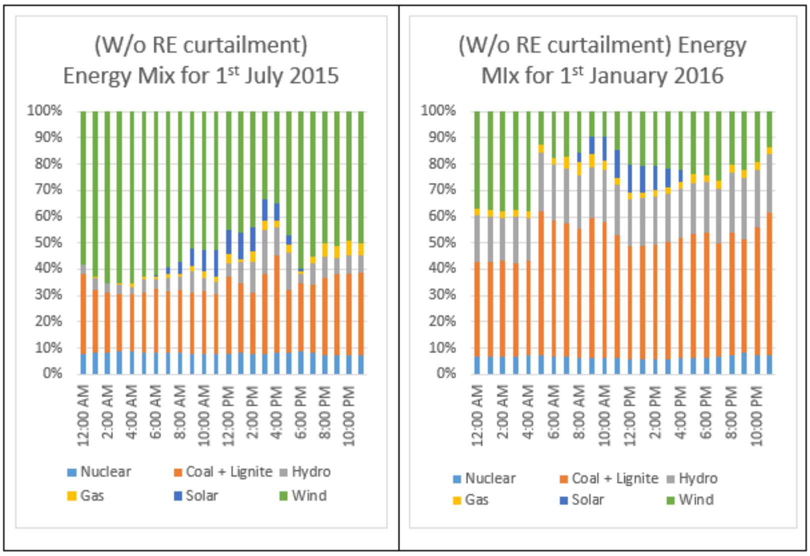
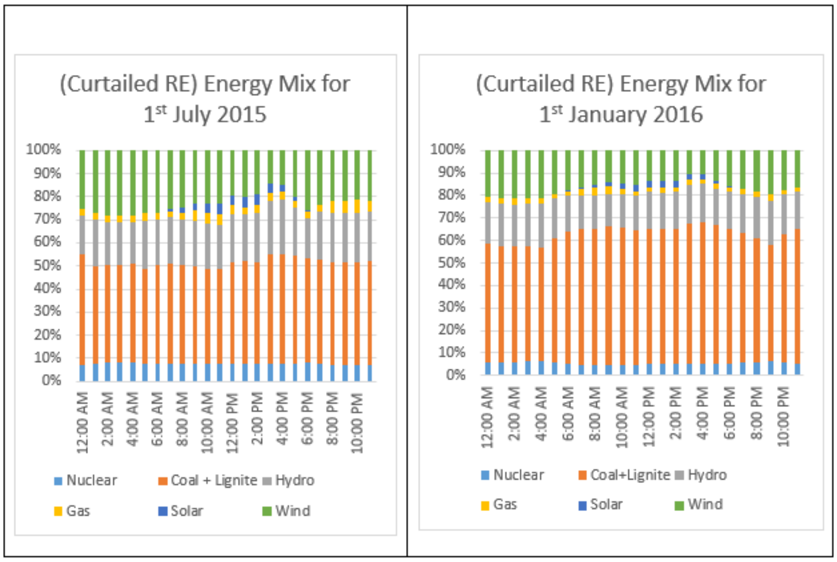


Figure 6: Optimal Daily Energy mix under Scenario B: RE curtailment at simulated RE utilisation levels of 2015-16



2. Daily trend in weighted cost of power procured from all available generation resources has been given in Figure 4.

Figure 7: Daily trend in hourly weighted average costs simulated by UCP-MIP model for Rajasthan on 1^{st} July 2015

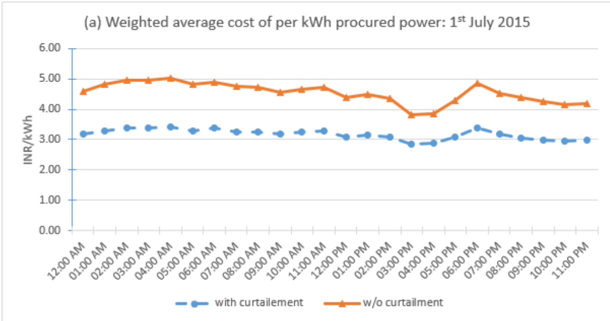
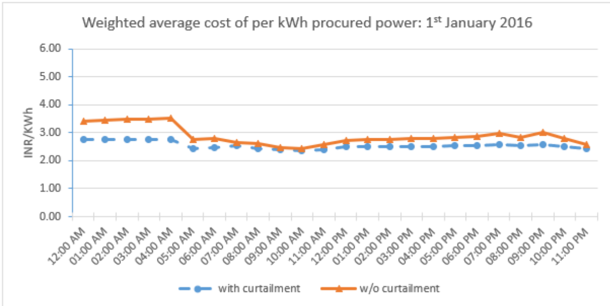


Figure 8: Daily trend in hourly weighted average costs simulated by UCP-MIP model for Rajasthan on 1^{st} January 2016



Further, we aggregated the minimized total power generation-cum-procurement costs obtained for each of the 12 months of 2015-16 under the MIP-UCP approach, under the assumption of RE *curtailment*. We arrived at approximately INR 100.85 billion as the annual costs of generation-cum-procurement of power for Rajasthan. This has been summarized in Figure 9.

Figure 9: Minimized total power generation-cum-procurement costs

*Model could not find a feasible solution

Month	Monthly Cost (without RE curtailment) in billion INR	Monthly Cost (with RE curtailment) in billion INR
April 2015	N/A *	7.502
May 2015	N/A *	7.481
June 2015	14.339	10.407
July 2015	11.197	7.403
August 2015	9.597	7.090
September 2015	13.076	11.384
October 2015	8.529	7.880
November 2015	9.958	9.451
December 2015	9.210	8.613
January 2016	9.947	9.252
February 2016	9.004	8.286
March 2016	8.298	6.075
Annual Power Procurement Cost (in billion INR)	N/A*	100.825

The officially documented Aggregate of Energy Charges (sans transmission charges and fixed charged) incurred towards all generating stations serving demand in Rajasthan for the year 2015-16 was INR 137.732 billion, as reported by RVPNL (State Transmission Utility: Rajasthan Rajya Vidyut Prasaran Nigam Limited) on behalf of the DISCOMS of Rajasthan in their Final Tariff Petition for 2015-16 (Rajasthan Electricity Regulatory Commission, 2016). This does not include large power consumers who source power directly from the generator, surpassing DISCOMs. This official figure exceeds our UCP-MIP estimates with the same average yearly rates of RE curtailment, by approximately INR 36.907 billion. This translates to a 26.80% savings in cost by estimate of this UCP-MIP model, over the current expenditure by Rajasthan DISCOMS.

Developed UCP-MIP model seems to provide a reasonable lower bound on the potential system-wide costs of sourcing power to serve demand, subject to operational constraints. However, one must note that there is possible underestimation of costs in our Rajasthan implementation since we aggregated monthly UCP results to save on computational complexity, without verifying that the schedule for the last time period of a month, can be taken as a feasible initialization for the second month. Had the model been run for all 8784 hours in one go, instead of 12 sub-problems, there would have been other inflexibility costs imposed to ensure continuous feasibility of the solution throughout the year.

6.1 Policy Implications

As demonstrated above in the case of Rajasthan, the transitioning to more advanced UC methods that are sensitive to generator-level and system-level technical constraints, in a manner that retains the stylised characteristics of the power sector in question can lead to significant potential financial savings. Moreover, since the formulation incorporates several facets observed in a real-life power system akin to India, it can not only provide insight to shape present-day policy in the Indian context, but also some other systems with some shared similarities. It is more aligned with India's future goals of a high proportion of grid-integrated RE. It would also be useful in informing the state planner in deciding the optimal generation portfolio. The calculated hourly weighted cost of purchasing per unit power from the vast, heterogeneous mix of available generation sources can prove useful in assisting the state planner (acting on behalf of all consumers in the state) to decide when to enter the short-term power market. If the spot market price is lower than the weighted cost of generation and procurement as given by UCP-MIP, the planner may choose to purchase a proportion of the required power in the short-term rather than sourcing all of it from its more expensive long-term resources.

7 Conclusion

In this paper we have presented a UCP for a state planner based on MIP. It has characteristics of federalized structure of power generation sources and an external market with both private and government players. The prices offered by these players are fixed usually through competitive bidding.

This model can advise regional (sub-national) level power systems to determine the optimal short-term scheduling operations in a manner that (a) meets the region's power demands and reserve requirements, and (b) minimises the cost of procuring the requisite power, subject to technical inter-temporal constraints.

The optimised weighted cost of power purchase in each time period, as determined by this model, could help inform a state planner in strategic decisions regarding its portfolio mix of long-term and short-term power transactions. This could be done through a comparison of the current power exchange price with the optimised weighted power cost in each time block. If the Power exchange prices are lower, the state would prefer to source some part of its demand from the spot market. However, this description ignores the key fact that the state planner/consumer also resorts to spot trading in the face of uncertainty of demand/generation.

References

Abujarad, S. Y., M. W. Mustafa, and J. J. Jamian (2017): "Recent approaches of unit commitment in the presence of intermittent renewable energy resources: A review," *Renewable and Sustainable Energy Reviews*, 70, 215–223.

Bistline, J. E. (2017): "Economic and technical challenges of flexible operations under large-scale variable renewable deployment," *Energy Economics*, 64, 363–372.

Carrión, M. and J. M. Arroyo (2006): "A computationally efficient mixed-integer linear formulation for the thermal unit commitment problem," *IEEE Transactions on power systems*, 21, 1371–1378.

Cebulla, F. and T. Fichter (2017): "Merit order or unit-commitment: How does thermal power plant modeling affect storage demand in energy system models?" *Renewable energy*, 105, 117–132.

Central Electricity Authority (CEA) (2013): "Tariff for sale of power from various Atomic Power Stations of NPCIL for the period from 01.07.2010 to 30.06.2015," Public Notice.

——— (2016): "CO2 Baseline Database for the Indian Power Sector: User Guide Version 11.0," Public Notice.

Central Electricity Regulatory Commission (CERC) (2014): "Operational Norm for Thermal Power Station, Tariff Period-2014-19," .

Cheng, C.-P., C.-W. Liu, and C.-C. Liu (2000): "Unit commitment by Lagrangian relaxation and genetic algorithms," *IEEE transactions on power systems*, 15, 707–714.

Delarue, E. and W. D'haeseleer (2007): "Advanced priority listing versus mixed integer programming in solving the unit commitment problem," .

Dlakic, M. (2010): "Mixed integer linear programming based thermal unit commitment problem in deregulated environment," *J. Electrical Systems*, 6, 466–479.

Dupont, N. (2015): "Wind power integration in Egypt and its impacts on unit commitment and dispatch," Master's thesis, Technical University of Denmarks.

GAMS Development Corporation (2017): "GAMS," .

Hawkes, A. and M. Leach (2009): "Modelling high level system design and unit commitment for a microgrid," *Applied energy*, 86, 1253–1265.

Huber, M., D. Dimkova, and T. Hamacher (2014): "Integration of wind and solar power in Europe: Assessment of flexibility requirements," *Energy*, 69, 236–246.

IBM (????): "IBM ILOG CPLEX Optimizer 2017," .

Kaltschmitt, M., W. Streicher, and A. Wiese (2007): *Renewable energy: technology, economics and environment*, Springer Science & Business Media.

Lee, C., C. Liu, S. Mehrotra, and M. Shahidehpour (2013): "Modeling transmission line constraints in two-stage robust unit commitment problem," *IEEE Transactions on Power Systems*, 29, 1221–1231.

Mercados Energy Market India Pvt. Ltd (2014): "Indian Power Market Journey so far and way forward," Tech. rep., University of Zurich, Department of Informatics.

Ministry of Power (2016): "TARIFF POLICY, No. 23/2/2005-R&R (Vol-IX)," Public Notice.

Ministry of Power, G. o. I. (2005): "National Electricity Policy 2005," Public Notice.

——— (2017): "MERIT app and e-Bidding portal for utilization of domestic coal in IPP Power Stations for reducing the cost of power generation launched," Public Notice.

——— (2018a): "Discussion Paper on Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India," Discussion Paper.

——— (2018b): "Flexibility in Generation and Scheduling of Thermal Power Stations to reduce emissions," Public Notice.

——— (2019 [Online].): "Need, not greed, has been India's guiding principle: says PM. Pledges to more than double India's renewable energy capacity target to 450 GW. PM Modi addresses Climate Action Summit," Public Notice.

Monast, J. J. (2019): "Electricity Competition and the Public Good: Rethinking Markets and Monopolies," *U. Colo. L. Rev.*, 90, 667.

Muckstadt, J. A. and S. A. Koenig (1977): "An application of Lagrangian relaxation to scheduling in power-generation systems," *Operations research*, 25, 387–403.

National Renewable Energy Laboratory (2017a): "National Solar Radiation Database (NSRDB)," Last accessed on: 05/20/2017.

——— (2017b): "System Advisor Model (SAM)," Last accessed on: 05/20/2017.

Nazari, M., M. Ardehali, and S. Jafari (2010): "Pumped-storage unit commitment with considerations for energy demand, economics, and environmental constraints," *Energy*, 35, 4092–4101.

Omar, A. I., Z. M. Ali, M. Al-Gabalawy, S. H. Abdel Aleem, and M. Al-Dhaifallah (2020): "Multi-objective environmental economic dispatch of an electricity system considering integrated natural gas units and variable renewable energy sources," *Mathematics*, 8, 1100.

Ott, A. L. (2010): "Evolution of computing requirements in the PJM market: Past and future," in *IEEE PES General Meeting*, IEEE, 1–4.

Power System Operation Corporation Ltd (2018): "Consultation Paper On Security Constrained Economic Despatch of Inter State Generating Stations pan India," Consultation Paper.

Power System Operation Corporation (POSOCO) (2016): "Flexibility Requirement in Indian Power System," https://posoco.in/download/flexibility_requirement_in_indian_power_system/?wpdmdl=711.

Prasad, A. A., R. A. Taylor, and M. Kay (2017): "Assessment of solar and wind resource synergy in Australia," *Applied Energy*, 190, 354–367.

Rajasthan Electricity Regulatory Commission (2016): "Petition No. RERC 552/15, 553/15 and 554/15," Public Notice.

Rajasthan Rajya Vidyut Prasaran Nigam Limited (2017): "Rajasthan Rajya Vidyut Prasaran Nigam Limited," https://energy.rajasthan.gov.in/rvpnl.

Richardson, D. B. and L. Harvey (2015): "Strategies for correlating solar PV array production with electricity demand," *Renewable Energy*, 76, 432–440.

Selvakumar, K., B. Vignesh, C. Boopathi, and T. Kannan (2016): "Thermal unit commitment strategy integrated with solar energy system," *Int J Appl Eng Res*, 11, 6856–6860.

Sen, S. and D. Kothari (1998): "Optimal thermal generating unit commitment: a review," *International Journal of Electrical Power & Energy Systems*, 20, 443–451.

Snyder, W. L., H. D. Powell, and J. C. Rayburn (1987): “Dynamic programming approach to unit commitment,” *IEEE Transactions on Power Systems*, 2, 339–348.

Sönmez, Y. (2013): “Estimation of fuel cost curve parameters for thermal power plants using the ABC algorithm,” *Turkish Journal of Electrical Engineering & Computer Sciences*, 21, 1827–1841.

Ummels, B. C., M. Gibescu, E. Pelgrum, W. L. Kling, and A. J. Brand (2007): “Impacts of wind power on thermal generation unit commitment and dispatch,” *IEEE Transactions on energy conversion*, 22, 44–51.

Van den Bergh, K., K. Bruninx, E. Delarue, and W. DâĂŹhaeseleer (2014): “LUSYM: a unit commitment model formulated as a mixed-integer linear program,” *KU Leuven, TME Branch Working Paper*, 7.

Wood, A. J., B. F. Wollenberg, and G. B. Sheblé (2013): *Power generation, operation, and control*, John Wiley & Sons.

Yamin, H. Y. (2004): “Review on methods of generation scheduling in electric power systems,” *Electric Power Systems Research*, 69, 227–248.

Zhao, B., Y. Shi, X. Dong, W. Luan, and J. Bornemann (2013): “Short-term operation scheduling in renewable-powered microgrids: A duality-based approach,” *IEEE Transactions on sustainable energy*, 5, 209–217.