Unit Commitment

1.0 Introduction

The problem of unit commitment (UC) is to decide which units to interconnect over the next T hours, where T is commonly 24 or 48 hours, although it is reasonable to solve UC for a week at a time. The problem is complicated by the presence of inter-temporal constraints, i.e., what you do in one period constrains what you can do in the next period. The problem is also complicated because it involves integer decision variables, i.e., a unit is either committed (1) or not (0).

The UC problem forms the basis of today's day-ahead markets (DAMs). Most ISOs today are running so-called security-constrained unit commitment (SCUC) 24 hours ahead of the real-time (balancing) market.

If one has a very good solution method to solve the UC problem (or the SCUC problem), then the good solutions that come will save a lot of money relative to using a not-so-good solution method. Regardless of the solution method, however, the solutions may not save much money if the forecast of the demand that needs to be met contains significant error. Having a "perfect" solution for a particular demand forecast is not very valuable if the demand forecast is very wrong. Therefore demand forecasting is very important for solving the UC. Systems that are expecting high wind energy penetrations are concerned about this fact, since high wind penetration increases demand forecast uncertainty (the demand that the thermal units must meet is load-wind). This is why so much attention is being paid to improving wind power forecasting. It is also why so much attention is being paid to creating UC models and solvers that handle uncertainty.

We begin these notes with a motivating example in Section 2.0, then we provide the explicit problem statement, in words, in Section 3.0. Section 4.0 articulates the problem in words, and Section 5.0 provides an analytic problem statement. Section 6.0 provides an overview of several good industry papers (which are posted on the website).

2.0 Motivating example

Assume we are operating a power system that has load characteristic as given in Fig. 1.

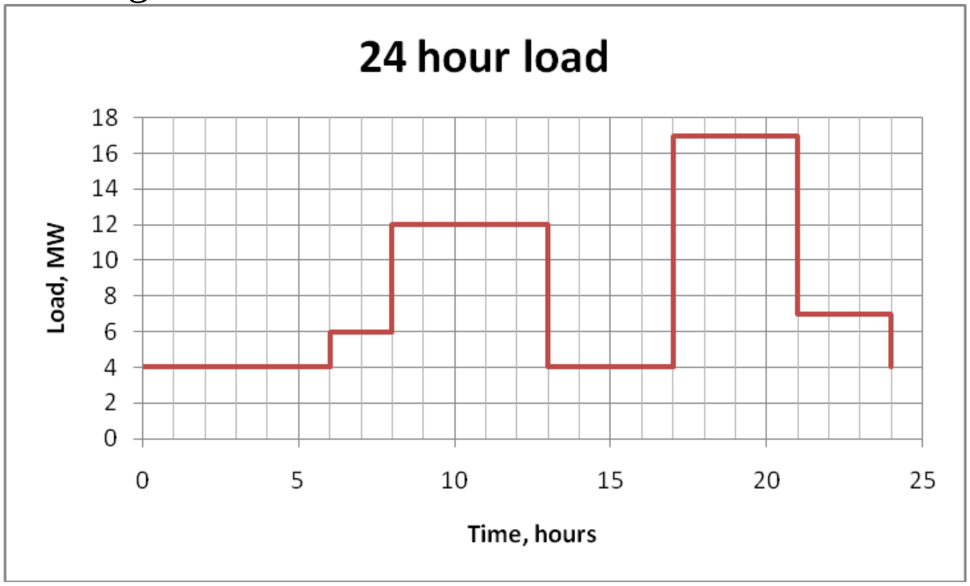


Fig. 1

Consider that we have three units to supply the load. The unit cost rates are expressed below.

$$C_1(P_{g1}) = 5 + 0.5P_{g1} + P_{g1}^2, \quad 0 \le P_{g1} \le 5$$
$$C_2(P_{g2}) = 5 + P_{g2} + 0.5P_{g2}^2, \quad 0 \le P_{g2} \le 10$$
$$C_3(P_{g3}) = 5 + 3P_{g3} + 2P_{g3}^2, \quad 0 \le P_{g3} \le 3$$

Note that the available capacity is 5+10+3=18.

In the economic dispatch problem, we identified the minimum cost for each hour, under the assumption that all units were on-line, or *committed*.

The UC problem differs from the economic dispatch problem in that we no longer assume that all of the units are committed. In fact, the essence of the UC problem is to decide which units to commit.

To begin consideration of the problem at hand, let's make the very significant assumption that there are no costs associated with a unit making the transition between up (connected) and down (disconnected).

Therefore our objective is to determine how to operate the three units in order to

- achieve the minimum cost over the 24 hour period and
- satisfy the load.

Let's consider two approaches for doing this.

Approach 1:

In this simple-minded approach, we will commit all units for the entire 24 hour period, and dispatch them according to economic dispatch at each hour.

Observe that this method will certainly satisfy the load. But it does not achieve minimum cost because, for example, we could simply run unit 1 by itself from 0 to 6 hours and not incur the automatic \$10/hr required by running units 2 and 3 with $P_{g2}=P_{g3}=0$.

So this is a very poor approach.

Approach 2:

Let's try to run only the necessary units for each load-level. But we need to decide which units.

To answer this question, let's consider that there are 7 possible combinations of units. We will denote each combination as S_k. They are enumerated below.

S_1: G_1
S_2: G_2
S_3: G_3
S_4: G_1, G_2
S_5: G_1, G_3
S_6: G_2, G_3
S_7: G_1, G_2, G_3

However, we observe that unit 3 is very expensive therefore let's run this unit only if we must. This means we will eliminate any of the above combinations that have G_3 except the last one. Therefore we now only have four possibilities:

S_1: G_1
S_2: G_2
S_3: G_1, G_2
S_4: G_1, G_2, G_3

We desire to determine which combination should be chosen at each of the various load levels.

To accomplish this, we will plot the total cost of each combination against total load, assuming the units committed are dispatched according to economic dispatch (without losses).

So we want to obtain a function $C_{Tk}(P_d)$ for each set S_k, k=1,2,3,4.

This is easy for S_1 because in this case, $P_d=P_{g1}$, and also for S_2, because in this case, $P_d=P_{g2}$. Therefore, we have

$$C_{T1}(P_d) = 5 + 0.5P_d + P_d^2, \quad 0 \le P_d \le 5$$

$$C_{T2}(P_d) = 5 + P_d + 0.5P_d^2, \quad 0 \le P_d \le 10$$

For S_3 and S_4, we have more than one generator, and so how do we get $C_{T3}(P_d)$?

Can we just add them up?

Yes, but that is not enough, because the cost depends on the functions *when they are optimized*. Just adding them up does not perform the optimization. So we could optimize on all sets at all load levels; then, for each load level, choose the set giving min cost.

We will do this but in a more illustrative way. What we will do is to write the optimality condition for each generator, which is

$$\lambda = \frac{\partial C_i}{\partial P_{gi}}$$

We will also use

$$P_d = \sum_{i=1}^{N} P_{gi}$$

where N=2 for S_3 and N=3 for S_4.

We go through the development for S_3 but just give the result for S_4.

<u>For S_3</u>:

$$\begin{aligned} C_{T3}(P_d) &= 5 + 0.5P_{g1} + P_{g1}^2 + 5 + P_{g2} + 0.5P_{g2}^2 \\ &= 10 + 0.5P_{g1} + P_{g1}^2 + P_{g2} + 0.5P_{g2}^2 \end{aligned} \quad , \qquad (\&)$$

Using the optimality condition:

$$, \quad \lambda = \frac{\partial C_1}{\partial P_{g1}} = \frac{\partial C_2}{\partial P_{g2}}$$

we can write that

$$0.5 + 2P_{g1} = 1 + P_{g2} \Rightarrow P_{g2} = 2P_{g1} - 0.5 \qquad (*)$$

From power balance, we have

$$P_d = P_{g1} + P_{g2} \qquad (**)$$

Substitution of (*) into (**) results in

$$P_d = P_{g1} + 2P_{g1} - 0.5 = 3P_{g1} - 0.5$$

Solving for P_{g1} results in

$$P_{g1} = \frac{P_d + 0.5}{3} \qquad (\#)$$

Substitution of (#) into (*) results in

$$P_{g2} = 2P_{g1} - 0.5 = 2\frac{P_d + 0.5}{3} - 0.5 = \frac{4P_d - 1}{6} \qquad (\#\#)$$

Substitution of (#) and (##) into (&) above results in

$$C_{T3}(P_d) = 10 + 0.5\left(\frac{P_d + 0.5}{3}\right) + \left(\frac{P_d + 0.5}{3}\right)^2 + \left(\frac{4P_d - 1}{6}\right) + 0.5\left(\frac{4P_d - 1}{6}\right)^2$$

and the above relation is applicable for $0 \le P_d \le 15$.

<u>For S_4</u>:

We will not go through the detailed algebra here but just give the result, which is

$$C_{T4}(P_d) =$$

$$15 + 0.5\left(\frac{P_d + 1.125}{3.5}\right) + \left(\frac{P_d + 1.125}{3.5}\right)^2 + 0.571P_d + 0.143$$

$$+ 0.5(0.571P_d + 0.143)^2 + 3(0.1429P_d - 0.4643) + 2(0.1429P_d - 0.4643)^2$$

and this relation is applicable for $0 \le P_d \le 18$.

Figure 2 plots C_{T1}, C_{T2}, C_{T3}, and C_{T4} together as a function of demand.

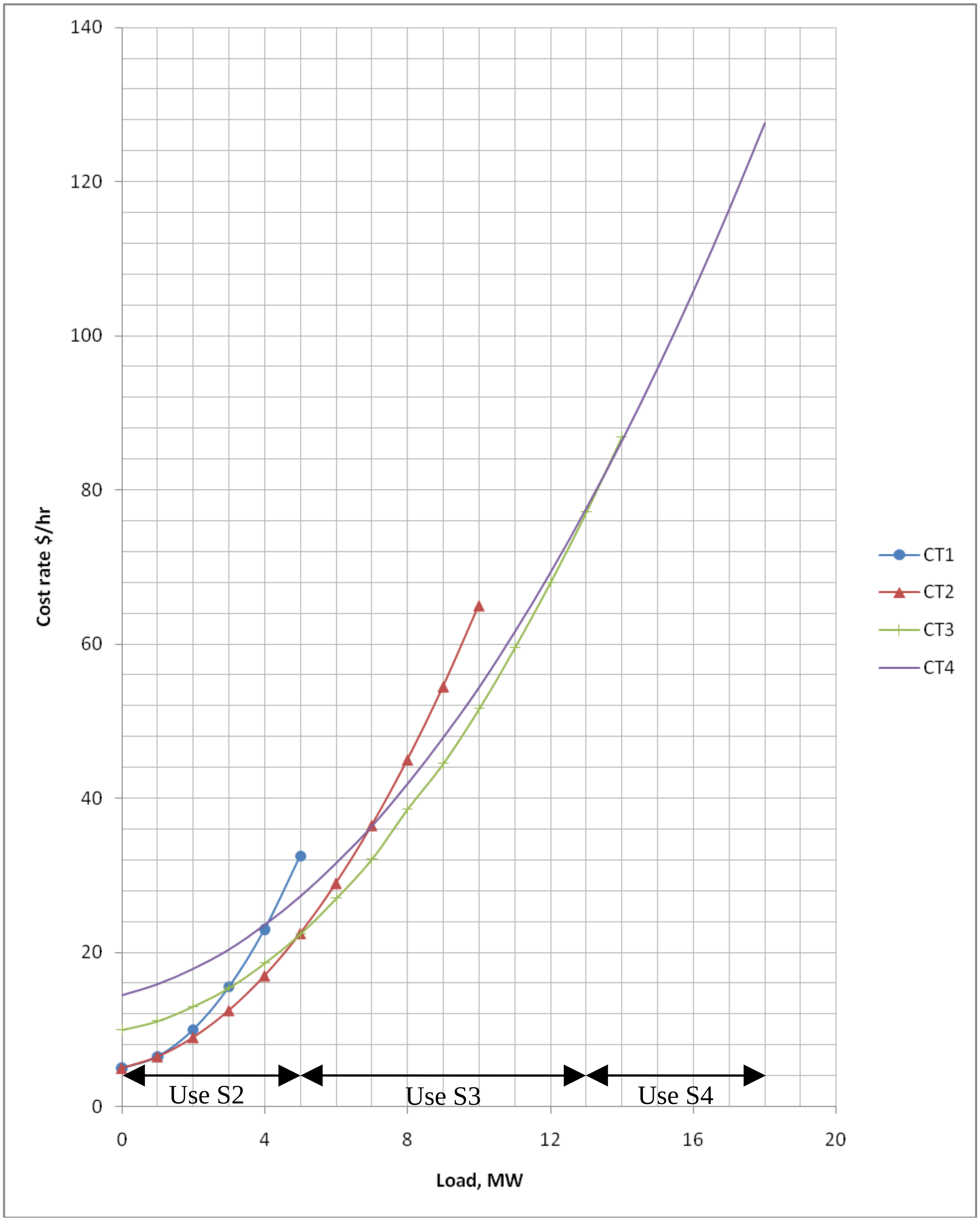


Fig. 2

Recall the generators comprising each set, repeated below for convenience, but now we indicate the load interval for which each set should be used.

S_1: G_1	NEVER
S_2: G_2	0-5
S_3: G_1, G_2	5-13
S_4: G_1, G_2, G_3	13-18

Now we return to the load characteristic of Fig. 1 and use Fig. 2 to identify the "solution" to that particular UC problem. The solution is given in Fig. 3.

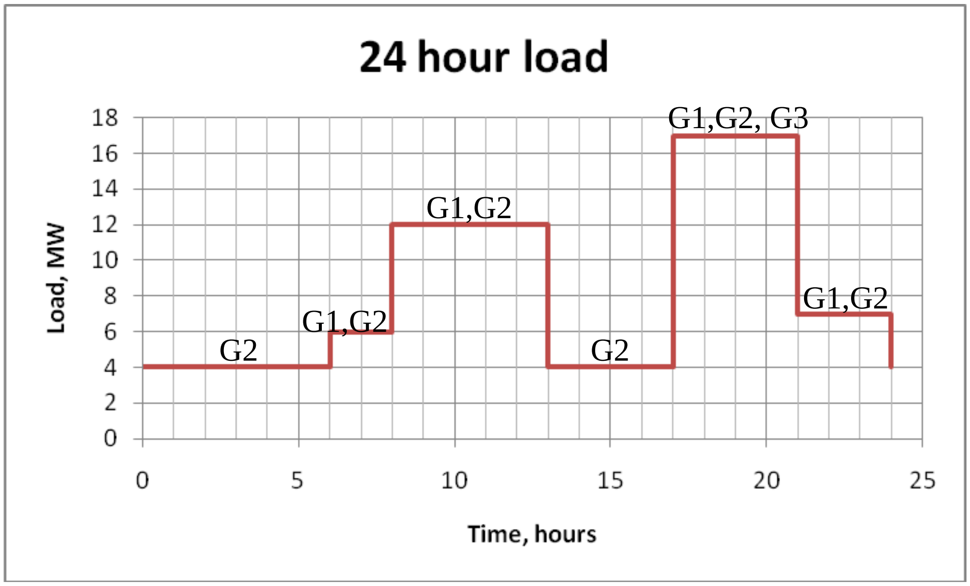


Fig. 3

It is important to note that we have solved this problem under the assumption that transition costs are zero. What if this is not the case?

Transition costs include startup costs and shutdown costs. Startup costs involve both fixed costs C_f and variable costs C_v and requires some further explanation.

Shutdown costs generally involve only fixed costs (mainly labor) and are easy to model. Sometimes they are neglected because they are generally not very significant.

The fixed startup costs (generally labor) will be denoted by C_f. The variable startup costs are denoted by C_V. (See pg. 137 of W&W).

Variable costs of start-up depend on the shut-down state the unit is in. There are two possibilities, depending on how "ready" we want the unit to be during its shutdown period. These two possibilities are

- Hot reserve (banking): This is when the unit is down, but the boiler is kept hot. The disadvantage of this state is that it costs money to supply the fuel to heat the boiler. The advantage of this state is the unit can be started quickly. It is also less expensive to start a unit from a hot reserve state since no startup fuel is required to heat the unit. A relation to estimate the variable costs in dollars of a hot reserve state is:

  $$C_{Vb} = [C_b t] f$$

  - C_b is the energy per hour to keep the boiler warm (MBTU/hr)
  - f is the cost per MBTU ($/MBTU)
  - t is the shutdown duration

  Note that C_{Vb} increases with time, without bound. Therefore the hot reserve state is typically more attractive if the unit will be down for only a short time.
- Cold reserve (cooling): This is when the unit is down and the boiler is not heated. The disadvantage of this state is that the colder the unit is, the more costly and more time to start. The advantage of this state is that there is no fuel cost while the unit is down. A relation to estimate the costs of a cold reserve state is

  $$C_{Vc} = C_c \left[1 - e^{-t/\alpha}\right] f$$

  - C_c is the fuel required to start the unit from completely cold (MBTU)
  - α is unit thermal time constant (time constant of thermal loss)
  - f is the cost per MBTU ($/MBTU)
  - t is the shutdown duration

  Note from the cold reserve equation that
- t=0 implies C_{Vc}=0, meaning the unit is not allowed time to cool.
- t=∞ implies $C_{Vc}=C_c f$, meaning the unit becomes completely cold.

3.0 Node-arc model of the UC problem

You will find below (and in problem 1 of HW7) that when including start-up costs, the peaks allow only one solution (S3) but the valleys allow three which we designate as follows:

S2-H: This is G2 up, with G1 in hot reserve

S2-C: This is G2 up, with G1 in cold reserve

S3: This is G1, G2 up.

You can see that the problem, peaks and valleys, admits only the above three possible states.

We will use a particular representation using nodes and arcs to model the situation where

- node: state of the system at the beginning of a period
- arc: possible path from a state in period i to a state in period i+1.

Notice the use of the term "state" here is to globally specify the status of all units in the system.

For a 72-hour situation, of our three possible states, only one, S_3, is feasible during the peaks when the demand is 11, but all three states are feasible during the valleys when the demand is only 3 or 4. Figures 4 and 5 represent the situation, where the system is initially (t=0) in state S3.

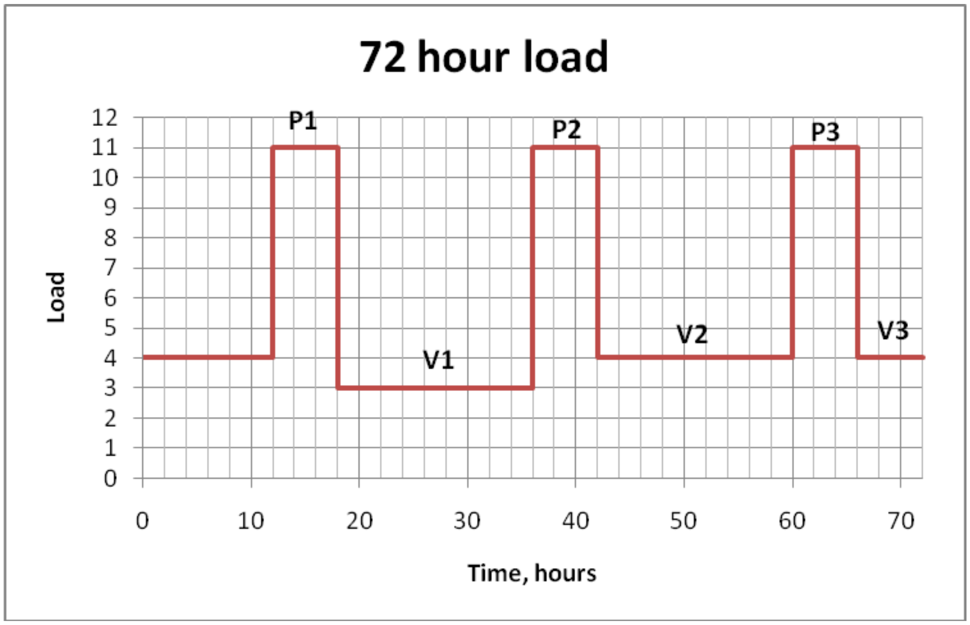

72 hour load
P1
P2
P3
V1
V2
V3
Load
Time, hours

Fig. 4

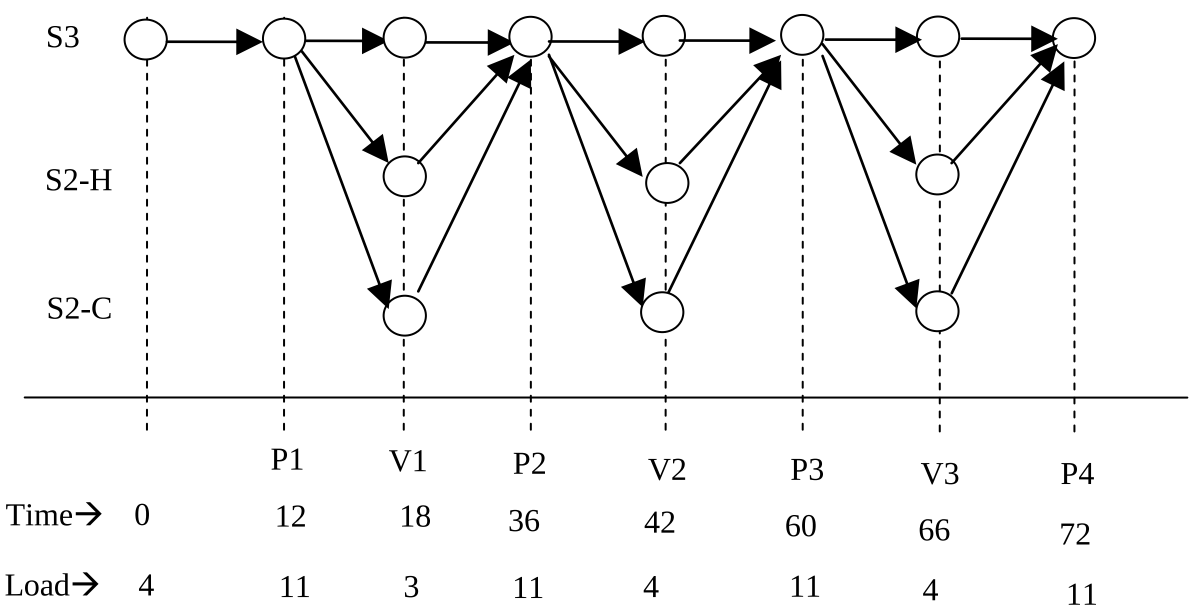

S3
S2-H
S2-C
P1
V1
P2
V2
P3
V3
P4
Time→ 0 12 18 36 42 60 66 72
Load→ 4 11 3 11 4 11 4 11

Fig. 5

We can also associate a value with each arc as the cost if the system is in the state from which the arc begins. We can compute these costs for each state and for each different load level.

I will not provide the expressions to make these computations (you will need to do that in your homework). Rather, I will just provide the results in terms of Fig. 6.

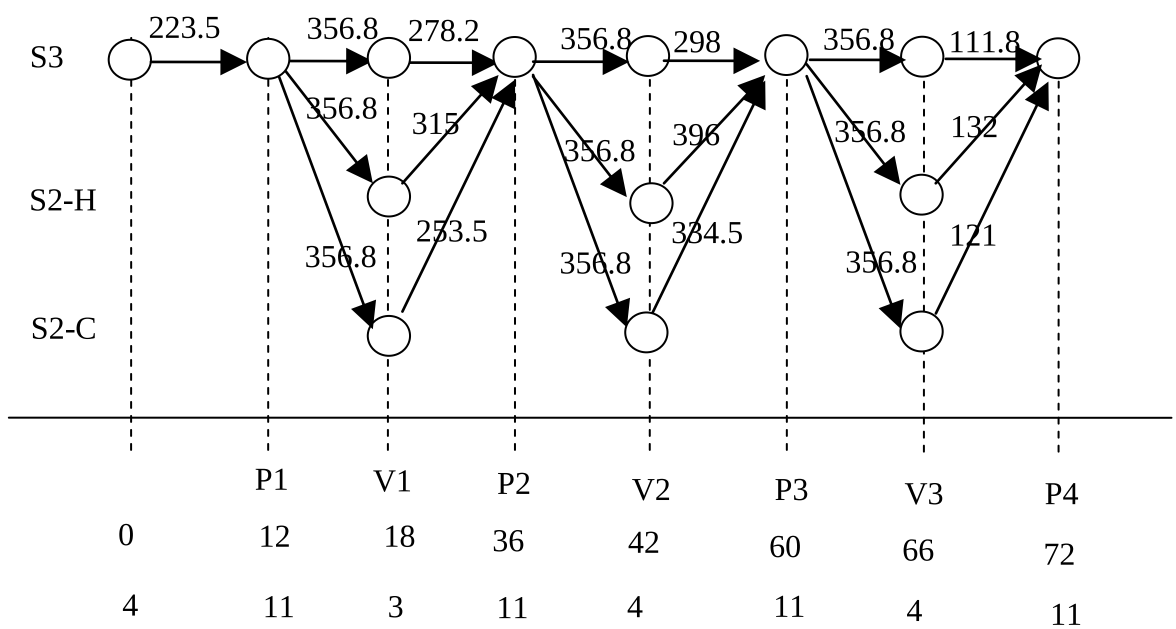
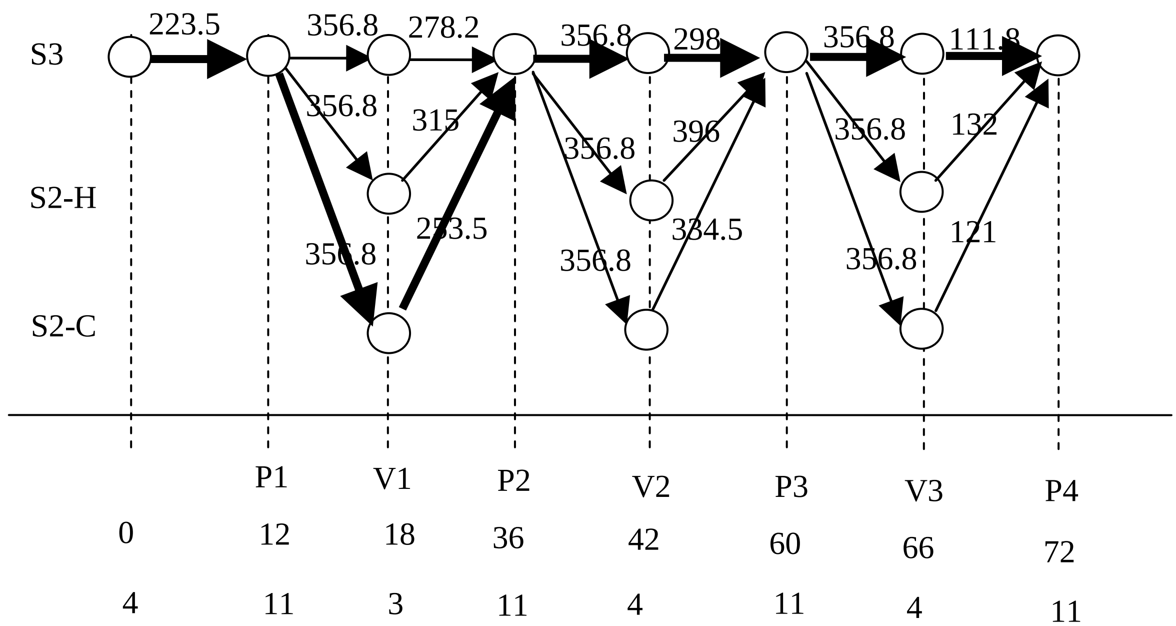


Fig. 6

Observe that the UC problem has been converted to a new problem…

Assume that the values on the arcs are arc-lengths. Then we desire to find the shortest path between the first and last node in the network.

It is easy to see the shortest path in our node-arc model, it is below.



But consider a case where we have N units instead of 3, where N is large.

Even if we limit the number of states per unit to two (on or off), and assume that all loading levels may be supplied by any one unit or by any combination of units, then at each time, there are 2^N-1 possible states (nodes) to consider (we subtract 1 because we do not consider the state where all units are off).

We may transition between any state in one time period and any state in the next time period, so that if we have 2^N-1 states per time period, with m time periods, then we will have a total number of possible solutions equal to $(2^N-1)^m$.

For example, consider where N=5 and m=24 (5 units over 24 time hours). In this case: $(2^5-1)^{24}$=6.2E35.

This represents the **curse of dimensionality**.

Two questions:

1. How do we limit the dimensionality of the problem?
2. How do we algorithmically solve the problem of how to find the shortest path?

Question 1:

There are two approaches:

A. Limit the number of nodes at each time interval.
B. Limit the number of possible transitions (arc) between time intervals.

Example:

Consider 3 gens with 2 possible states (nodes): on or off.
The total number of nodes possible at any time interval is 7.

But let's now prioritize the units using the following rule:

We always turn on unit i before unit i+1. Therefore, we now only have 3 possible states (nodes), as follows:

$S_1=G_1$

$S_2=G_1G_2$

$S_3=G_1G_2G_3$

In general, this rule creates all states $S_i=G_1G_2\ldots G_i$

The prioritization rule is typically done according to economic criteria and security criteria. It is sometimes referred to as "merit order."

Note also that this limits the transitions if you can quantify the maximum possible load variation for one period, see Fig. 7.

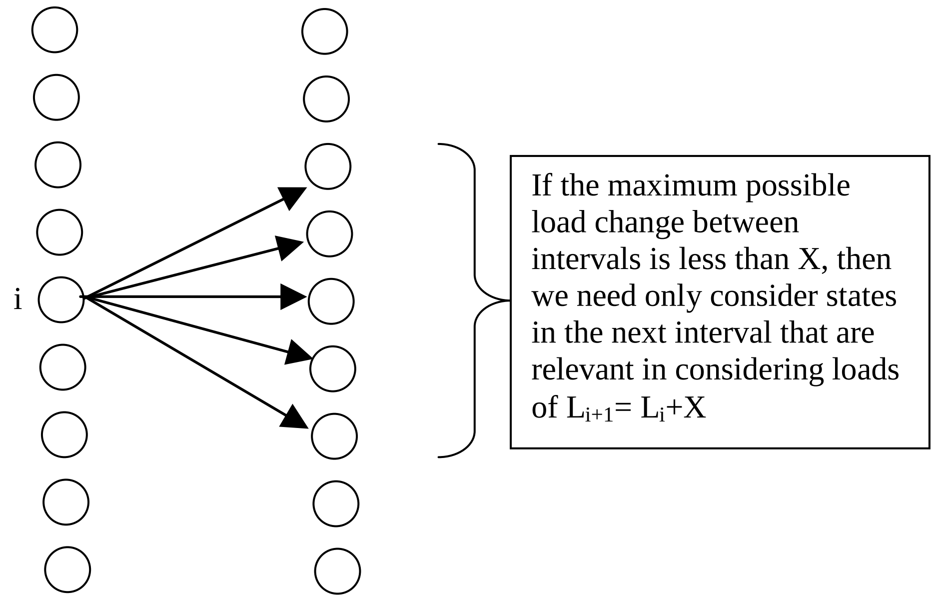


Fig. 7

Question 2: How to algorithmically solve the "shortest path" problem?

Several alternatives:

- Dijkstra's algorithm
- Dial's algorithm
- Label correcting algorithms
- All-pair algorithm
- Dynamic programming: forward and backward.

Dynamic programming was used many years ago, and W&W cover it well in Section 5.2.2. It has now has fallen out of favor to what are called branch and bound (B&B) methods. We will spend most of our time on B&B methods. First, however, we provide a textual (Section 4) and an analytic (Section 5) problem statement.

4.0 Problem statement

The unit commitment problem is solved over a particular time period *T*; in the day-ahead market, the time period is usually 24 hours. It is articulated in [10], in words, as follows:

1. Min Objective=UnitEnergyCost+StartupCost+ShutdownCost
+DemandBidCost

Subject to:

2. Area Constraints:
    a. Demand + Net Interchange
    b. Spinning and Operating Reserves
3. Zonal Constraints:
    a. Spinning and Operating Reserves
4. Security Constraints
5. Unit Constraints:
    a. Minimum and Maximum Generation limits
    b. Reserve limits
    c. Minimum Up/Down times
    d. Hours up/down at start of study
    e. Must run schedules
    f. Pre-scheduled generation schedules
    g. Ramp Rates
    h. Hot, Intermediate, & Cold startup costs
    i. Maximum starts per day and per week
    j. Maximum Energy per day and per study length

We describe the objective function and the various constraints in what follows.

<u>4.1 Objective function</u>

a. *UnitEnergyCost*: This is the total costs of supply over *T*, based on the supply offers made, in $/MWhr.

b. *StartupCost*: This is the total cost of starting units over *T*, based on the startup costs

c. *ShutdownCost*: This is the total cost of shutting down units over T, based on the shutdown costs.

d. *DemandBidCost*: This is the total "cost" of demand over *T*, based on the demand bids made, in $/MWhr. Revenue demand bids are added as negative costs so that by minimizing the objective the profit is maximized.

4.2 Area constraints

a. *Demand + Net Interchange*: The area demand plus the exports from the area (which could be negative, or imports).

b. *Spinning and Operating Reserves*: The spinning reserve is the amount of generation capacity $\Sigma(P_{gmax,k}-P_{gen,k})$ in MW that is on-line and available to produce energy within 10 minutes. Operating reserve is a broader term: the amounts of generating capacity scheduled to be available for specified periods of an Operating Day to ensure the security of the control area. Generally, operating reserve includes primary (which includes spinning) and secondary reserve, as shown in Fig. 8.

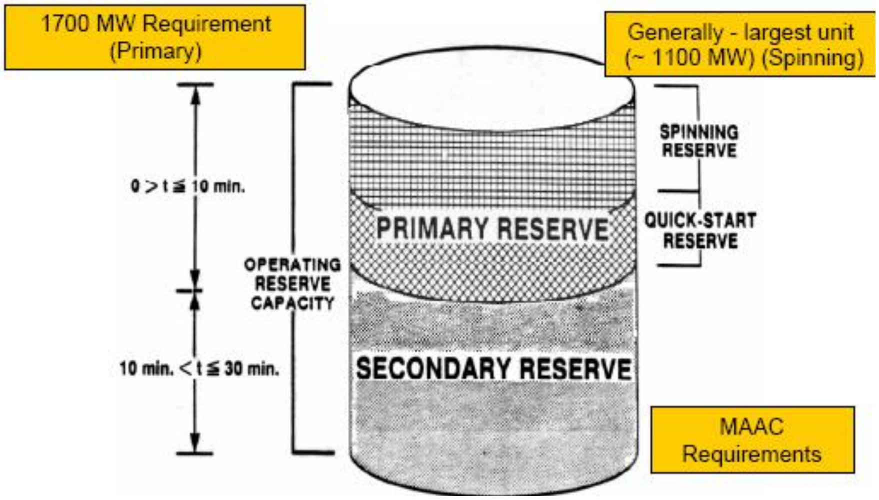


Fig. 8 [1]

4.3 Zonal constraints

Some regions within the control area, called zones, may also have spinning and operating reserve constraints, particularly if transmission interconnecting that region with the rest of the system is constrained.

4.4 Security constraints

These include constraints on branch flows under the no-contingency condition and also constraints on branch flows under a specified set of contingency conditions. The set is normally a subset of all N-1 contingencies.

4.5 Unit constraints

a. *Minimum and Maximum Generation limits*: Self explanatory.

b. *Reserve limits*: The spinning, primary, and/or secondary reserves must exceed some value, or some percentage of the load.

c. *Minimum Up/Down times*: Units that are committed must remain committed for a minimum amount of time. Likewise, units that are de-committed must remain down for a minimum amount of time. These constraints are due to the fact that thermal units can undergo only gradual temperature changes.

d. *Hours up/down at start of study*: The problem must begin at some initial time period, and it will necessarily be the case that all of the units will have been either up or down for some number of hours at that initial time period. These hours need to be accounted for to ensure no unit is switched in violation of its minimum up/down times constraint.

e. *Must run schedules*: There are some units that are required to run at certain times of the day. Such requirements are most often driven by network security issues, e.g., a unit may be required in order to supply the reactive needs of the network to avoid voltage instability in case of a contingency, but other factors can be involved, e.g., steam supply requirements of co-generation plants.

f. *Pre-scheduled generation schedules*: There are some units that are required to generate certain amounts at certain times of the day. The simplest example of this is nuclear plants which are usually required to generate at full load all day. Import, export, and wheel transactions may also be modeled this way.

g. *Ramp Rates*: The rate at which a unit may increase or decrease generation is limited, therefore the generation level in one period is constrained to the generation level of the previous period plus the generation change achievable by the ramp rate over the amount of time in the period.

h. *Hot, Intermediate, & Cold startup costs*: A certain amount of energy must be used to bring a thermal plant on-line, and that amount of energy depends on the existing state of the unit. Possible states are: hot, intermediate, and cold. Although it costs less to start a hot unit, it is more expensive to maintain a unit in the hot state. Likewise, although it costs more to start a cold unit, it is less expensive to maintain a unit in the cold state. Whether a de-committed unit should be maintained in the hot, intermediate, or cold state, depends on the amount of time it will be off-line.

i. *Maximum starts per day and per week*: Starting a unit requires people. Depending on the number of people and the number of units at a plant, the number of times a particular unit may be started in a day, and/or in a week, is usually limited.

j. *Maximum Energy per day and per study length*: The amount of energy produced by a thermal plant over a day, or over a certain study time T, may be less than $P_{max} \times T$, due to limitations of other facilities in the plant besides the electric generator, e.g., the coal processing facilities. The amount of energy produced by a reservoir hydro plant over a time period may be similarly constrained due to the availability of water.

5.0 The UC problem (analytic statement)

The unit commitment problem is a mathematical program characterized by the following basic features.

- *Dynamic*: It obtains decisions for a sequence of time periods.
- *Inter-temporal constraints*: What happens in one time period affects what happens in another time period. So we may not solve each time period independent of solutions in other time periods.
- *Mixed Integer*: Decision variables are of two kinds:

- Integer variables: For example, we must decide whether a unit will be up (1) or down (0). This is actually a special type of integer variable in that it is binary.
- Continuous variables: For example, given a unit is up, we must decide what its generation level should be. This variable may be any number between the minimum and maximum generation levels for the unit.

There are many papers that have articulated an analytical statement of the unit commitment problem, more recent ones include [7, 8, 2, 3], but there are also more dated efforts that pose the problem well, although the solution method is not as effective as what we have today, an example is [4].

We provide a mathematical model of the security-constrained unit commitment problem in what follows. This model was adapted from the one given in [5, ch 1]. This model is a mixed integer linear program.

$$\min \quad \underbrace{\sum_t \sum_i z_{it} F_{it}}_{\text{Fixed Costs}} + \underbrace{\sum_t \sum_i g_{it} C_{it}}_{\text{Production Costs}} + \underbrace{\sum_t \sum_i y_{it} S_{it}}_{\text{Startup Costs}} + \underbrace{\sum_t \sum_i x_{it} H_{it}}_{\text{Shutdown Costs}} \tag{1}$$

subject to

power balance $$\sum_i g_{it} = D_t = \sum_i d_{it} \qquad \forall t, \tag{2}$$

reserve $$\sum_i r_{it} \geq SD_t \qquad \forall t, \tag{3}$$

min generation	$g_{it} \geq z_{it} MIN_i$	$\forall\, i, t,$	(4)
max generation	$g_{it} + r_{it} \leq z_{it} MAX_i$	$\forall\, i, t,$	(5)
max spinning reserve	$r_{it} \leq z_{it} MAXSP_i$	$\forall\, i, t,$	(6)
ramp rate pos limit	$g_{it} \leq g_{it-1} + MxInc_i$	$\forall\, i, t,$	(7)
ramp rate neg limit	$g_{it} \geq g_{it-1} - MxDec_i$	$\forall\, i, t,$	(8)
start if off-then-on	$z_{it} \leq z_{it-1} + y_{it}$	$\forall\, i, t,$	(9)
shut if on-then-off	$z_{it} \geq z_{it-1} - x_{it}$	$\forall\, i, t,$	(10)
normal line flow limit	$\sum_i a_{ki}(g_{it} - d_{it}) \leq MxFlow_k$	$\forall\, k, t,$	(11)
security line flow limits	$\sum_i a_{ki}^{(j)}(g_{it} - d_{it}) \leq MxFlow_k^{(j)}$	$\forall\, k, j, t,$	(12)

where the decision variables are:
- g_{it} is the MW produced by generator *i* in period *t*,
- r_{it} is the MW of spinning reserves from generator *i* in period *t*,
- z_{it} is 1 if generator *i* is dispatched during *t*, 0 otherwise,
- y_{it} is 1 if generator *i* starts at beginning of period *t*, 0 otherwise,
- x_{it} is 1 if generator *i* shuts at beginning of period *t*, 0 otherwise,

Other parameters are
- D_t is the total demand in period *t*,
- SD_t is the spinning reserve required in period *t*,
- F_{it} is fixed cost ($/period) of operating generator *i* in period *t*,
- C_{it} is prod. cost ($/MW/period) of operating gen *i* in period *t*;
- S_{it} is startup cost ($) of starting gen *i* in period *t*.
- H_{it} is shutdown cost ($) of shutting gen *i* in period *t*.
- $MxInc_i$ is max ramprate (MW/period) for increasing gen *i* output
- $MxDec_i$ is max ramprate (MW/period) for decreasing gen *i* output
- a_{ij} is linearized coefficient relating bus *i* injection to line *k* flow
- $MxFlow_k$ is the maximum MW flow on line *k*
- $a_{ki}^{(j)}$ is linearized coefficient relating bus *i* injection to line *k* flow under contingency *j*,
- $MxFlow_k^{(j)}$ is the maximum MW flow on line *k* under contingency *j*

The above problem statement is identical to the one given in [5] with the exception that here, we have added eqs. (11) and (12).

➔The addition of eq. (11) alone provides that this problem is a transmission-constrained unit commitment problem.
➔ The addition of eqs. (11) and (12) together provides that this problem is a security-constrained unit commitment problem.

One should note that our problem is entirely linear in the decision variables. Therefore this problem is a *linear* mixed integer program, and it can be compactly written as

$$\min \underline{c}^T \underline{x}$$

Subject to

$$\underline{A}\underline{x} \le \underline{b}$$

There have four basic solution methods used in the past few years:

- Priority list methods
- Dynamic programming
- Lagrangian relaxation
- Branch and bound

The last method, branch and bound, is what the industry means when it says "MIP." It is useful to understand that the chosen method can have very large financial implications. This point is well-made in the chart [6] of Fig. 9.

	Current Approach	Planned Approach	Date of Planned Implementation of MIP	Estimated Annual Savings
Real-time market look ahead	LR used for 2 hour look ahead commitment and dispatch	MIP: 2 hour look ahead for dispatch. As long as 5 hours for commitment .	April 1, 2008	~$100,000-$1 million (0.1%-1%1 of 2006 RT Dispatch Costs and RT RMR Costs2: $97 million)
Residual unit commitment	Procedural based operator judgement advised by a MIP based UC with no network	Run a MIP, Full Network Model based on Residual Unit Commitment after Day-Ahead bid market.	April 1, 2008	~$100,000-$1 million (based on 0.1% - 1% of Total Minimum Load Costs for 2006: $106 million)
day-ahead market	Linear Programing: No unit commitment, No Energy Optimziation, Allocation of Transmission only using zonal model	Run a MIP based SCUC/SCED, Full Network Model program, Energy and A/S co-optimized	April 1, 2008	~$2.3-$23 million (Assumes an estimated 0.1%-1% reduction of $11.4 billion Energy and Ancillary Service)
Capacity market	None	Policy being considered	Policy being considered	No Estimate
Ancillary service market	Linear Programming sequential procured after Transmission Allocation	Run a MIP based SCUC/SCED, Full Network Model program co-optimized with energy	April 1, 2008	~$230,000-$2.3 million (0.1%-1%[1] of 2006 A/S costs[2] of $234 million)
planning	Powerflow studies	No immediate plans to incorporate MIP	No immediate plans to incorporate MIP	No Estimate

Fig. 9

6.0 UC and Day-ahead market

The main tool used to implement the day-ahead-markets (DAM) is the security-constrained unit commitment program, or SCUC. In this section, we review some basics about the DAM by looking at some descriptions given by a few industry authors. You are encouraged to review the papers from which these quotes were taken. Notice that any references made inside the quotations are given only in the bibliography of the subject paper and not in the bibliography of these notes. References made outside of the quotations are given in the bibliography of these notes.

6.1 Paper by Chow & De Mello:

Reference [7] offers an overall view of the sequence of functions used by an ISO, as given in Fig. 10. Observe that the "day-ahead scheduling" and the "real time commitment and dispatch" both utilize the SCUC.

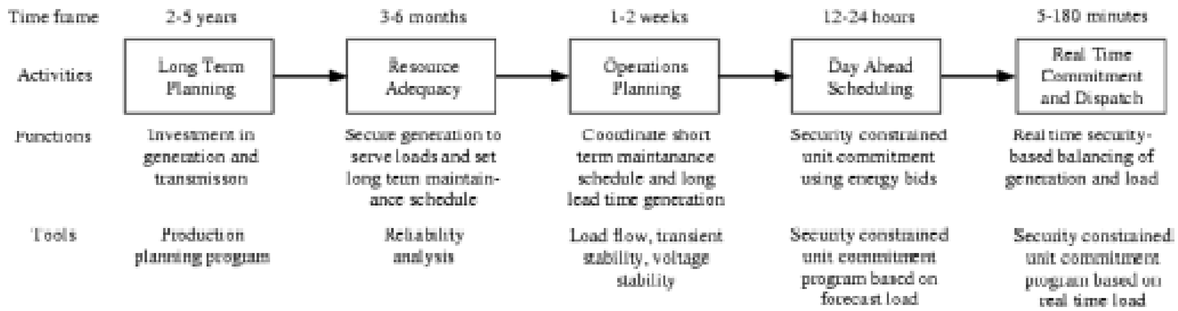


Fig. 10

They state:
"Electricity is a commodity that cannot be effectively stored and the energy-supplying generators have limits on how quickly they can be started and ramped up or down. As a result, both the supply and demand become more inelastic and the electricity market becomes more volatile and vulnerable as it gets closer to real time [34]. To achieve a stable margin as well as to maintain the system reliability, a forward market is needed to provide buyers and sellers the opportunity to lock in energy prices and quantities and the ISO to secure adequate resources to meet predicted energy demand well in advance of real time. Thus architecturally, many ISOs (e.g. PJM, ISO New England, New York ISO) take a multisettlement approach for market design…."

"The two main energy markets, each producing a financial settlement, in a multisettlement system, are the following.
1) DAM: schedules resources and determines the LMPs for the 24 h of the following day based on offers to sell and bids to purchase energy from the market participants.
2) Real-time market: optimizes the clearing of bids for energy so that the real-time system load matching and reliability requirements are satisfied based on actual system operations. LMPs are computed for settlement at shorter intervals, such as 5–10 min…."

"Fig. 6 shows the timeline of the multiple-settlement systems used in NYISO, PJM, and ISO-NE, which are typical of those used in practice. Supply and demand bids are submitted for the DAM, typically 12–24 h ahead of the real-time operation. Then the day-ahead energy prices are computed and posted, 6–12 h ahead of real-time operation…."

"The DAM typically consists of supply and demand bids on an hourly basis, usually from midnight to the following midnight. The supply bids include generation supply offers with start-up and no-load costs, incremental and decremental bids[1], and external transactions schedules. The demand bids are submitted by loads individually or collectively through load-serving entities. In scheduling the supply to meet the demand, all the operating constraints such as transmission network constraints, reserve requirements, and external transmission limits must not be violated. This process is commonly referred to as an SCUC problem, which is to determine hourly commitment schedules with the objective of minimizing the total cost of energy, start-up, and spinning at no-load while observing transmission constraints and physical resources' minimum runtime, minimum downtime, equipment ramp rates, and energy limits of energy-constrained resources. Based on the commitment schedules for physical resources, SCUC is used to clear energy supply offers, demand bids, and transaction schedules, and to determine LMPs and their components at all defined price nodes including the hubs, zones, and aggregated price nodes for the DAM settlement. The SCUC problem is usually optimized using a Lagrangian relaxation (LR) or a mixed-integer programming (MIP) solver…."

[1] Decremental bids are similar to price-sensitive demand bids. They allow a marketer or other similar entity without physical demand to place a bid to purchase a certain quantity of energy at a certain location if the day-ahead price is at or below a certain price. Incremental offers are the flip side of decremental bids. Usually, a decremental bid is a fee paid by suppliers to the ISO when it no longer requires the full amount of energy previously contracted for, due to congestion. The ISO must purchase electricity elsewhere to make up the shortfall, and the generator reimburses the ISO. A bilateral generator with a decremental bid is saying: "Schedule me as a bilateral, must-run plant unless the spot price falls to (or below) my bid. In that event, don't schedule me as must run; I will supply my bilateral load from the spot market."

"A critical part of the DAM is the bid-in loads, which is a day-ahead forecast of the real-time load. The load estimate depends on the season, day type (weekday, weekend, holiday), and hour of the day. Most ISOs have sophisticated load forecasting programs, some with neural network components [36], [37], to predict the day-ahead load to within 3%–5% accuracy and the load forecasts are posted. LSEs with fully hedged loads through long-term bilateral contracts tend to bid in the amount corresponding to the ISO predicted loads. Some other LSEs may bid in loads that are different from those posted by the ISO. In such cases, if the LSE bid load exceeds the ISO load, the LSE bid load is taken as the load to be dispatched. Otherwise, the ISO load will supersede the LSE bid load and the SCUC will commit generators to supply the ISO forecasted load in a reliability stage. Then the generation levels of the committed generators will be allocated to supply LSE bid loads. Committing extra generators outside the DAM will be treated as uplifts and be paid by the LSEs…."

6.2 Paper by Papalexopoulos:

Reference [8] states:

"The Must Offer Waiver (MOW) process is basically a process of determining which Must Offer units should be committed in order to have enough additional capacity to meet the system energy net short which is the difference between the forecast system load and the Day-Ahead Market energy schedules. This commitment process ensures that the resulting unit schedule is feasible with respect to network and system resource constraints. Mathematically, this can be stated as a type of a SCUC problem [3]. The objective is to minimize the total start up and minimum load costs of the committed units while satisfying the power balance constraint, the transmission interface constraints, and the system resource constraints, including unit inter-temporal constraints…."

"The most popular algorithms for the solutions of the unit commitment problems are Priority-List schemes [4], Dynamic Programming [5], and Mixed Integer Linear Programming [6]. Among these approaches the MILP technique has achieved significant progress in the recent years [7]. The MILP methodology has been applied to the SCUC formulation to solve this MOW problem. Recent developments in the implementation of MILP-based algorithms and careful attention to the specific problem formulation have made it possible to meet accuracy and performance requirements for solving such large scale problems in a practical competitive energy market environment. In this section the MILP-based SCUC formulation is presented in detail…."

6.3 Paper by Ott:

Reference [9] states:
"In addition to the LMP concept, the fundamental design objectives of the PJM day-ahead energy market are: 1) to provide a mechanism in which all participants have the opportunity to lock in day-ahead financial schedules for energy and transmission; 2) to coordinate the day-ahead financial schedules with system reliability requirements; 3) to provide incentive for resources and demand to submit day-ahead schedules; and 4) to provide incentive for resources to follow real-time dispatch instructions…."

6.4 Paper by AREVA and PJM:

Reference [10] states:
"As the operator of the world's largest wholesale market for electricity, PJM must ensure that market-priced electricity flows reliably, securely and cost-effectively from more than 1100 Generating resources to serve a peak load in excess of 100,000 MW. In doing so, PJM must balance the market's needs with thousands of reliability-based constraints and conditions before it can schedule

and commit units to generate power the next day. The PJM market design is based on the Two Settlement concept [4]. The Two-Settlement System provides a Day-ahead forward market and a real-time balancing market for use by PJM market participants to schedule energy purchases, energy sales and bilateral contracts. Unit commitment software is used to perform optimal resource scheduling in both the Day-ahead market and in the subsequent Reliability Analysis…."

"As the market was projected to more than double its original size, PJM identified the need to develop a more robust approach for solving the unit commitment problem. The LR algorithm was adequate for the original market size, but as the market size increased, PJM desired an approach that had more flexibility in modeling transmission constraints. In addition, PJM has seen an increasing need to model Combined-cycle plant operation more accurately. While these enhancements present a challenge to the LR formulation, the use of a MIP formulation provides much more flexibility. For these reasons, PJM began discussion with its software vendors, in late 2002, concerning the need to develop a production grade MIP-based approach for large-scale unit commitment problems…."

"The Day-ahead market clearing problem includes next-day generation offers, demand bids, virtual bids and offers, and bilateral transactions schedules. The objective of the problem is to minimize costs subject to system constraints. The Day-ahead market is a financial market that provides participants an operating plan with known compensation: If their generation (or load) is the same in the real-time market, their revenue (or cost) is the same. Compensation for any real-time deviations is based on real-time prices, providing participants with opportunities to improve profit (or reduce cost) if they have flexibility to adjust their schedules…."

“In both problems, unit commitment accepts data that define bids (e.g., generator constraints, generator costs, and costs for other resources) and the physical system (e.g., load forecast, reserve requirements, security constraints). In real time, the limited responsiveness of units and additional physical data (e.g., state estimator solution, net-interchange forecast) further constrains the unit commitment problem.”

“The Unit Commitment problem is a large-scale non-linear mixed integer programming problem. Integer variables are required for modeling: 1) Generator hourly On/Off-line status, 2) generator Startups/Shutdowns, 3) conditional startup costs (hot, intermediate & cold). Due to the large number of integer variables in this problem, it has long been viewed as an intractable optimization problem. Most existing solution methods make use of simplifying assumptions to reduce the dimensionality of the problem and the number of combinations that need to be evaluated. Examples include priority-based methods, decomposition schemes (LR) and stochastic (genetic) methods. While many of these schemes have worked well in the past, there is an increasing need to solve larger (RTO-size) problems with more complex (e.g. security) constraints, to a greater degree of accuracy. Over the last several years, the number of units being scheduled by RTOs has increased dramatically. PJM started with about 500 units a few years ago, and is now clearing over 1100 each day. MISO cases will be larger still….”

“The classical MIP implementation utilizes a Branch and Bound scheme. This method attempts to perform an implicit enumeration of all combinations of integer variables to locate the optimal solution. In theory, the MIP is the only method that can make this claim. It can, in fact, solve non-convex problems with multiple local minima. Since the MIP methods utilize multiple Linear Programming (LP) executions, they have benefited from recent advances in both computer hardware and software [6]…”

"This section presents results from using the CPLEX 7.1 and CPLEX 9.0 MIP solvers on a large-scale RTO Day Ahead Unit Commitment problem. This problem has 593 units and a 48 hour time horizon…."

The below reference provides a brief description of the Midwest ISO's current implementation:

> M. Tackett, "Experience with implementing simultaneous co-optimization in the midwest ISO energy and operating reserve markets," Power Systems Conference and Exposition, 2009. PSCE '09. IEEE/PES.

"The Midwest ISO will operate a Day-Ahead Energy and Operating Market, a Reliability Assessment Commitment process and a Real-Time Energy and Operating Reserve Market.

- The Day-Ahead Energy and Operating Reserve Market is a financially binding market that clears energy, regulating reserve, spinning reserve and supplemental reserve on an hourly basis.
- The Reliability Assessment Commitment (RAC) process is a process to commit resources, schedule regulating reserve on committed resources and/or release emergency operating ranges on resources when appropriate on an hourly basis for use in the Real-Time Energy and Operating Reserve Market. The RAC process can be executed on a multi-day, day-ahead and/or intra-day basis.
- The Real-Time Energy and Operating Reserve Market is a financially and physically binding market that clears energy, regulating reserve, spinning reserve and supplemental reserve on a five-minute basis.

Three functions:
-DAM/ORM
-RAC
-RTM/ORM

The Midwest ISO will utilize a simultaneously co-optimized Security Constrained Unit Commitment (SCUC) algorithm and a simultaneously co-optimized Security Constrained Economic Dispatch (SCED) algorithm to operate the Day-Ahead Energy and Operating Reserve Market. The simultaneously co-optimized SCUC algorithm is used in the Day-Ahead Energy and Operating Reserve Market to commit resources, schedule regulating reserves on committed resources and/or release emergency operating ranges on resources in the Day-Ahead Energy and Operating Reserve Market. The simultaneously co-optimized SCED algorithm is used in the Day-Ahead Energy and Operating Reserve Market to clear and price energy, regulating reserve, spinning reserve

DAM/ORM require SCUC

DAM/ORM require SCED for hourly.

and supplemental reserve on an hourly basis. Demand curves are utilized to price Energy and Operating Reserve during times of scarcity.

The Midwest ISO will utilize a simultaneously co-optimized Security Constrained Unit Commitment (SCUC) algorithm to implement the RAC process and a simultaneously co-optimized Security Constrained Economic Dispatch (SCED) algorithm to operate the Real-Time Energy and Operating Reserve Market. The simultaneously cooptimized SCUC algorithm is used in the RAC process to commit resources, schedule regulating reserves on committed resources and/or release emergency operating ranges on resources for the Real-Time Energy and Operating Reserve Market. The simultaneously co-optimized SCED algorithm is used in the Real-Time Energy and Operating Reserve Market to dispatch and price energy, regulating reserve, spinning reserve and supplemental reserve on a five-minute basis. Demand curves are utilized to price Energy and Operating Reserve during times of scarcity.

RAC requires SCUC.

RTM/ORM requires SCED.

The SCUC algorithms used in the Day-Ahead Energy and Operating Reserve Market and the RAC process incorporate Mixed Integer Programming (MIP) solvers to commit resources, schedule regulating reserve on resources and release emergency operating ranges on resources (minimum or maximum) when inadequate capacity exists to meeting energy demand plus operating reserve requirements. The SCED algorithms used in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market use Linear Programming (LP) solvers to clear and price energy, regulating reserve, spinning reserve and supplemental reserve in a manner that minimizes production costs.

In both the Day-Ahead and Real-Time Energy and Operating Reserve Markets, reserve requirement constraints are modeled against cumulative reserve requirements to ensure operating reserve pricing is consistent with operating reserve priority for each of the three operating reserve products. Reserve Zones are also utilized to ensure dispersion of operating reserve throughout the market in a manner that allows for deliverability and good utility practice. Reserve zones are established quarterly and reserve zone requirements are updated daily based on the results of off-line studies."

Some good description of the Midwest ISO's reliability assessment commitment (RAC) is found in the below paper:

> Xingwang Ma, Yonghong Chen, Jie Wan, "Midwest ISO Co-Optimization Based Real-Time Dispatch And Pricing of Energy and Ancillary Services," 2009.

"Real-time grid reliability is at the center of Midwest ISO's cooptimized energy and AS design. While resource schedules are cleared as financially, not physically binding, the day-ahead market is critically linked to real-time operation through the reliability assessment commitment (RAC) and the two-settlement mechanism that guarantees resource adequacy for reliability and enables participants to arbitrage price differences between dayahead and real-time markets respectively. The DA market cleared financially binding resource schedules form the basis for the DA RAC by which sufficient resources are committed using the security-constrained unit commitment (SCUC) to meet Midwest ISO's demand forecasts and AS requirements subject to transmission limits. The DA RAC resource commitment schedules make the operating plan for the next day. During the operating day, more accurate information about demand forecasts, net scheduled interchanges (NSI) and transmission limitations is available; the RAC algorithm may be executed several times during the operating day, called intra-day (ID) RAC process, to further update the operating plan. The intra-day operating plan updates allow Midwest ISO operations to prepare sufficient resources at the right locations to manage load-generation-NSI balances and transmission congestions under normal and emergency conditions. With this integrated market-driven scheduling process, Midwest ISO uses the security-constrained economic dispatch (SCED) to achieve real-time reliable grid operation at the lowest costs. Energy deliveries and AS dispatches are priced based on actual system conditions after the fact."

RAC links DAM to real-time operations.

RAC is used to update the DA-schedules as new info becomes available.

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