

Market Optimization

2008 System Operator Seminar
Annapolis, MD & Pittsburgh, PA

- Discuss basic elements of electricity market optimization
- Learn how to calculate production costs
- Discuss Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) examples
- Learn about factors impacting market operations and optimization
- Class exercise: SCUC with start up cost calculations
- Discuss common LMP myths and misunderstandings
- Defining “ The Perfect Dispatch Initiative”

- Optimization is defined as “to make as perfect, effective, or functional as possible”
- In math, optimization refers to “the study of a **problem** in which one seeks to minimize or maximize an objective function”
 - An objective function is the goal, target, or “objective” that you are trying to achieve
- Therefore, in energy markets...

- The “**problem**” is the commitment and dispatch of energy market resources subject to many various constraints and parameters
 - Reliability transmission constraints
 - Generator operating constraints
- The “**objective function**” is usually the minimization of total production cost

G1: \$5000 start-up cost, first 100MW @ \$40, next 100MW @ \$80

G2: \$1000 start-up cost, 100MW @ \$30

What is the total production cost to run G1 at 100MW and G2 at 100MW?

What is the total production cost to run both generators at full output?

Note: hourly no load \$ not considered with these calculations

- The DA objective function is more complicated than RT as DA market includes many components like:
 - Price Sensitive Demand (PSD), INC, DEC, Transactions....
- DA objective is to minimize all bids assuming that non-generator bids are modeled as simplified generators bids (no EconMin, start up cost, min Run time)
- Price sensitive demand (and DEC bids) can be modeled as fixed load bid and generator off-setting load bid if LMP is high

Security Constrained Unit Commitment

- Security Constrained Unit Commitment is the process of turning on (committing) resources to meet load and other market requirements at the lowest possible cost (price) with respect to transmission limitations to ensure reliability

Sorting Generator Offers Merit Order

Gen offers received



G1: 201MW @ \$60
G2: 300MW @ \$40
G3: 300MW @ \$90
G4: 200MW @ \$20
G5: 101MW @ \$50

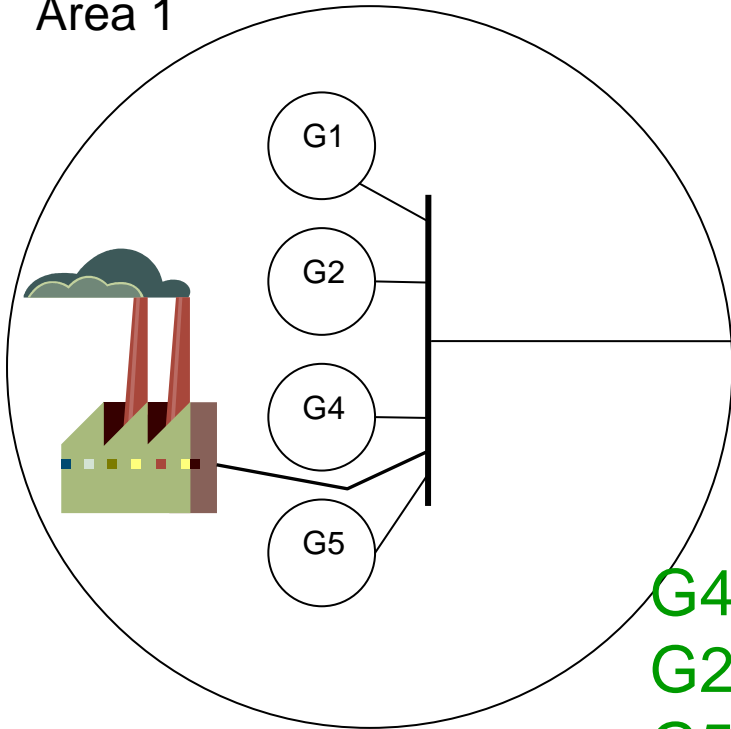
Gen offers sorted in price order



1. G4: 200MW @ \$20
2. G2: 300MW @ \$40
3. G5: 101MW @ \$50
4. G1: 201MW @ \$60
5. G3: 300MW @ \$90

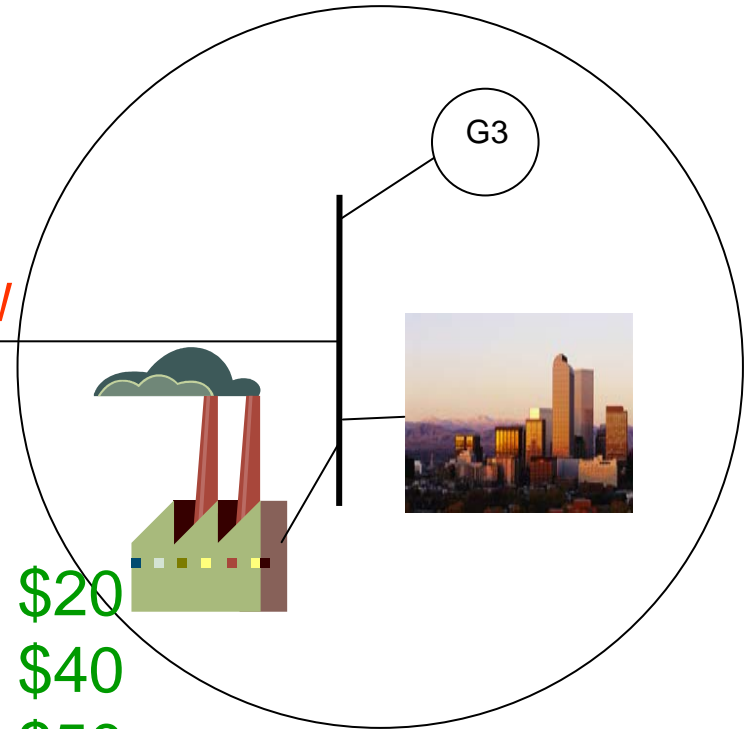
Price \$	Gen 1	Gen 2	Gen 3	Gen 4	Gen 5	Total MW
Minimum					50	50
10						
20				200		250
30						
40		300				550
50					101	601
60	201					802
70						
80						
90			300			1102
100						
Max	201	300	300	200	101	1102

Area 1



Load = 200MW

Area 2



Load = 600MW

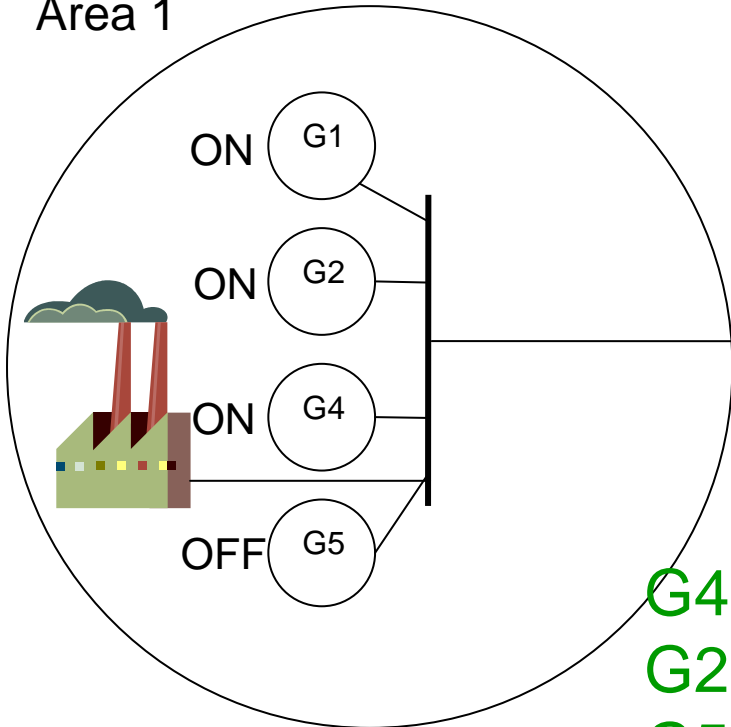
Limit = 400MW

- G4: 200MW @ \$20
- G2: 300MW @ \$40
- G5: 101MW @ \$50
- G1: 201MW @ \$60
- G3: 300MW @ \$90

Security Constrained Economic Dispatch (SCED)

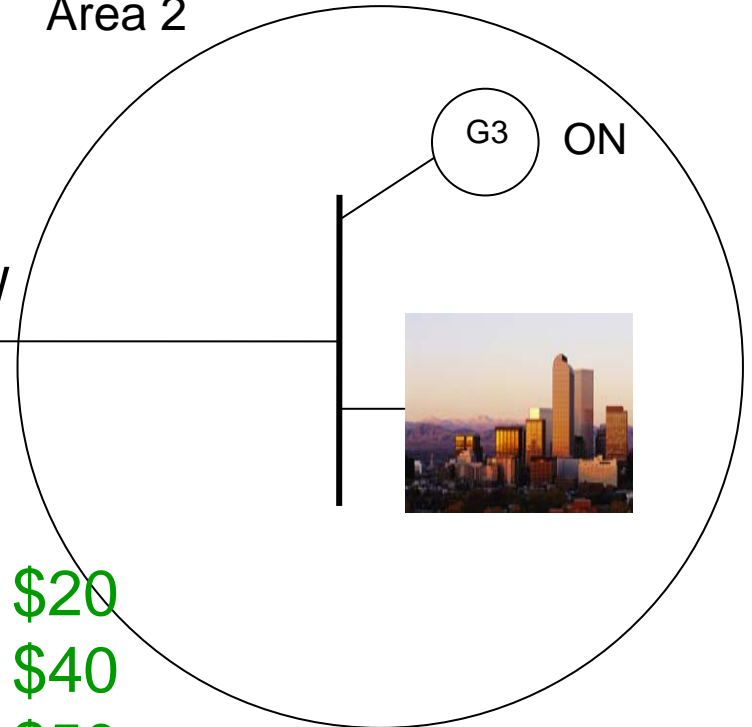
- Economic dispatch computes final dispatch and LMPs for a given unit commitment
 - SCED follows unit commitment and determines the level at which each resource should be operated
- SCED, like SCUC, enforces the “security” aspects of the transmission grid
 - Some people may refer to SCED as a single time interval solution (single hour in DA, 5 minutes as used in PJM RT today)
 - SCED in DA means all 24 hours solved together
- SCED must also consider operational limitations of generating plants, though these considerations may be different than limitations in SCUC
 - Ramp limitations are important, start-up costs no longer a factor

Area 1



Load = 200MW

Area 2



Load = 600MW

Limit = 400MW

G4: 200MW @ \$20
 G2: 300MW @ \$40
 G5: 101MW @ \$50
 G1: 201MW @ \$60
 G3: 300MW @ \$90

- Each generator has different characteristics that it submits to PJM along with their energy bid
- These variables can be cost-based, time-based, or a physical parameter:
 - Cost variables: Start-up cost, no-load cost
 - Time variables: Notification time, start-up time, min-run time, min-down time
 - Physical parameters: Min and Max, ramp rate

- Definition:
 - Cost to start a generator
- Important to optimization because:
 - It is factored into the total production cost
 - High start-up costs may preclude a unit with an attractive energy bid from being started
 - Example: A large, inexpensive coal unit may not be started near the end of the day as it will not recover start-up cost within the last few hours of the day

- PJM DA rules allow a unit to be in 3 stages
 - Hot
 - Intermediate (after being off for more than defined Hot->Intermed hours)
 - Cold
- In each state, a unit has different start up time and start up cost
 - SCUC may start unit earlier in the hot state and lose \$\$\$ on energy rather than start later to avoid paying higher start up cost later – this is one factor considered during SCUC run

- MUST run self-scheduled units are not paid start up cost
- Units MUST run by PJM personnel are paid start up cost

- **Definition:**
 - The hourly fixed cost, expressed in \$/hr, to run the generating unit at zero net output
- **Important to optimization because:**
 - It is factored into the total production cost
 - High no-load costs may prevent a unit with an attractive energy bid from commitment in some or all hours

- Example:
 - Unit bids \$20/MW and has a no-load cost = \$1000
 - At output level of 100 MW average production cost of 1 MW
 $= (1000+20*100)/100 = \$30/\text{MW}$
 - At output level of 200 MW average production cost of 1 MW
 $= (1000+20*200)/200 = \$25/\text{MW}$
 - More output results in lower average cost per MW
 - Mathematicians call such function non-convex and generally do not like them, as a unique solution is difficult to find. Such problems may have many “local minimums”

- **Definition:**
 - The time interval between PJM notification and the start sequence of a generating unit
- **Important to optimization because:**
 - Large units with long notification times may not be available to the program, depending on the solution time window
 - Units may be economically attractive but unavailable – at least in the eyes of the optimization
 - Units with notification + start-up time greater than 32 hours can never be started by DA software, even if it bid \$0/MW

- **Definition:**
 - The time interval from the actual unit start sequence to the unit economic min for a generating unit
 - Units may have hot, intermediate, cold start-up times
- **Important to optimization because:**
 - Large units with long start-up times may not be available to the program, depending on the solution time window
 - Units that may have been off-line longer will have longer start-up times
 - Units may be economically attractive but unavailable – at least in the eyes of the optimization
 - Units with notification + start-up time greater than 32 hours can never be started by DA software, even if it bid \$0/MW

- Definition:
 - The minimum number of hours a unit must run
- Important to optimization because:
 - A unit may be needed for fewer hours than its minimum run time
 - Decisions may need to be made whether to run a unit “out of merit” in off peak hours to satisfy demand in peak hours

- Units with long MinRun times can't be scheduled "precisely" based on LMP only within DA environment
- What to do with steam unit with a 24-hour minRun time?
 - If units starts in the middle of the day, it has to run the second day, but second day's data/bids may not be known and thus scheduling is difficult
 - Unit receives uplift payment based on day 1 revenue only. What will happen with uplift for day 2?

- **Definition:**
 - The minimum number of hours between unit shutdown and start-up
- **Important to optimization because:**
 - Units may be economically attractive but unavailable – at least in the eyes of the optimization

- Definition:
 - The lowest or highest economic MW output level a unit can achieve while following system cost
- Important to optimization because:
 - Optimization programs are bound by the economic min and max
 - In the case of the minimum, the optimization may want less MW from a unit but will not be allowed to do so, creating inflexibility or “LMP lumpiness”

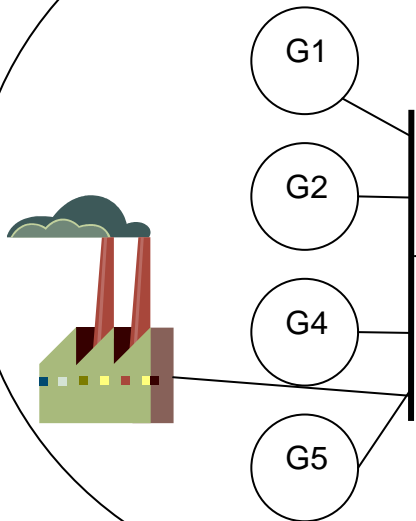
- **Definition:**
 - The rate, expressed in MW per minute, at which a generating unit can change output level
- **Important to optimization because:**
 - The dispatch program may want the generator at a higher level than the unit is able to achieve
 - It may take a few hours to achieve the desired dispatch level, forcing the optimization to decide whether to commit and/or ramp the unit sooner or choose other resources

- Ramping limits during unit start is somewhat difficult to enforce
 - As DA unit is always allowed to “jump to EconMin” in one hour
- Enforcing of ramping limits during units stops are semi-automated
- Ramp rates may not be strictly enforced in DA for self-scheduled units defining inconsistent EconMin and EconMax as shown in example below if ramp=1MW/Min
 - Hour 1:00 Min=60, Max 120
 - Hour 2:00 Min=240, Max 300
 - Unit can't get from Hour 1 Max (120) to Hour 2 Min (240) in one hour

- Many types of generators can't (or do not want) to start many times. Generators can define maximum number of starts per day and per week.
 - DA software enforces the maximum starts per day effectively
 - Max starts per week is semi-automated

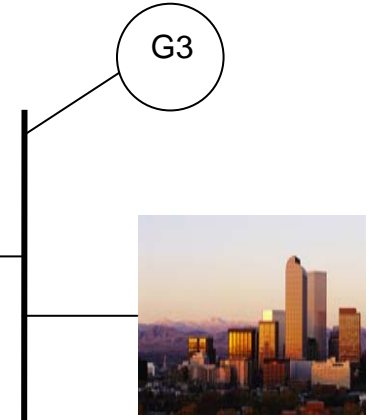
Area 1

Load = 200MW



Area 2

Load = 600MW



System Load
800 MW

Limit = 400MW

- G1: 200MW @ \$60, SU=\$1000
- G2: 300MW @ \$40, SU=\$3000
- G3: 300MW @ \$90, SU=\$6000
- G4: 200MW @ \$20, SU=\$10,000
- G5: 100MW @ \$50, SU=\$1000

SCUC Solution considering Start Up Cost

Exercise Summary:

- Generators 1, 2, 3 and 5 are committed to meet the 800 MW load
- Total production cost for the system is \$58K

$$G1 + G2 + G3 + G5 = \$58K$$

$$200 + 300 + 200 + 100 = 800 \text{ MW}$$

$$\$13K + \$15K + \$24K + \$6K = \$58K$$

Why not run G3 at full output and not start G5?

It is less costly to start G5 then run G3 at full out put. 100MW additional energy from G3 costs \$9K.

G5's total production cost is 6K for 100MW. Hence it is cheaper to start G5 than increase G3's output.

1. LMP is minimized by the optimization software
2. LMP cannot be negative
3. LMP cannot exceed the highest bid or a bid cap
4. The LMP at a location is equal to the bid of the marginal unit
5. SCED minimizes load payments
6. Transmission constraints always increase load payments

“Perfect Dispatch”

- Objectively evaluate PJM's performance in:
 - Dispatching the system in the most efficient manner possible
 - Optimizing locational pricing as a reflection of the dispatch solution
- Achieve continuous improvement with respect to dispatch and market operations

Why Measure Perfect Dispatch?

Our dispatch decision to improve reliability above minimum levels have a cost

- Financial
 - Costs our generators money
 - Increases costs to the load servers
 - Prevents full realization of the benefits of the PJM market for all participants
- Practical issues:
 - Increased wear and tear on the generators
 - Excessive emissions

- **Topology Changes**
 - Forced Outages (On in the DA case, off in RT)
 - Early Returns (Off in the DA case, on in RT)
 - PAR Settings (Differences in the DA and RT settings)
- **Interchange**
 - Forecast accuracy (forecast schedules vs. actual schedules)
 - External events (e.g., tripping on an external system)
- **Load Forecast Error**
- **Weather change (forecast temperatures vs. actual temperatures; forecast THI vs. actual THI)**
 - Storms (frontal storm; severe storm –t-storms, hurricanes, blizzards, etc.)
- **Generator Performance**
 - Set point deltas
 - CT time delays in starting or stopping
 - Self-scheduled generation
- **Control Performance**
 - Frequency volatility (impact of frequency bias)

- Simulate the previous day's operations in an off-line tool that determines the optimal dispatch solution
- Calculate established metrics from the optimal solution
- Calculate the same metrics based on the actual dispatch from the operating day
- Compare the results from the optimal case to those of the actual dispatch to determine the difference

- Primary metric will be Bid Production Cost
- Other metrics will also be established in order to help pinpoint specific dispatch decisions that were not optimal. Such metrics could include:
 - Balancing Operating Reserve payments
 - Total MW dispatched
 - Total number of and units dispatched
 - Others?

- An objective function is designed to maximize or minimize a value, such as costs, profits, etc.
- Linear programming is not used much outside of the energy industry
- In energy market software, production cost includes only energy bids
- Unit commitment will always turn on the generator with the cheapest energy bid regardless of other parameters
- If load increases by 1MW in an unconstrained system, economic dispatch will generally select the cheapest MW from on-line units only (assuming no losses)

QUESTIONS ?