# Power System Economics and Market Modeling

## M6: OPF Reserve Markets

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# Introduction

- In order to prevent load disconnections and loss of stability during normal operation or in the case of unexpected events, power systems should operate with an adequate level of Reserve.
- Reserve is an ancillary service ***needed*** for the successful operation of the system and the electricity market.
- This service can be obtained in a regulated, mandatory manner, or it can be provided by an Ancillary Services Reserves Market.

# Reserve Markets

- In the Reserves Market the generators (and sometimes loads) supply bids to sell the ***ability*** to take demand (increase their output) in a fast manner if called to do so.
- Similar to electricity markets for energy, which deal with active power, the reserve market focuses on ***active*** power reserves only.

# Reserve Resource Controls

- Generators can provide the following types of reserve:
  - Regulation Reserve (RR) is provided by online fast units, usually tied to AGC primary control, and capable to regulate the small positive or negative imbalances caused by the random nature of loads.
  - Spinning Reserve (SR) is provided by online units and is used to take larger variations of load and losses and unexpected events.
  - Supplemental Reserve (XR) is provided by online or offline fast-start units. This type of reserve is used to correct large imbalances caused by contingencies.

# Reserve Resource Controls

- While spinning and supplemental reserve are positive quantities, regulation reserve is a bidirectional control.
- Two ways to model regulation reserve controls, both supported in Simulator:
  - As two independent controls: regulation reserve up ($RR^+$) and regulation reserve down ($RR^-$). These controls can have different positive values.
  - As a single control. In this case the unit provides the same amount of regulating reserve in both directions.

# Reserve Resource Controls

- Spinning and supplemental reserves combined together provide Contingency Reserve (CR)
- Contingency reserve plus regulating reserve up is called Operating Reserve (OR)
- We can summarize this as follows:

SR + XR = CR

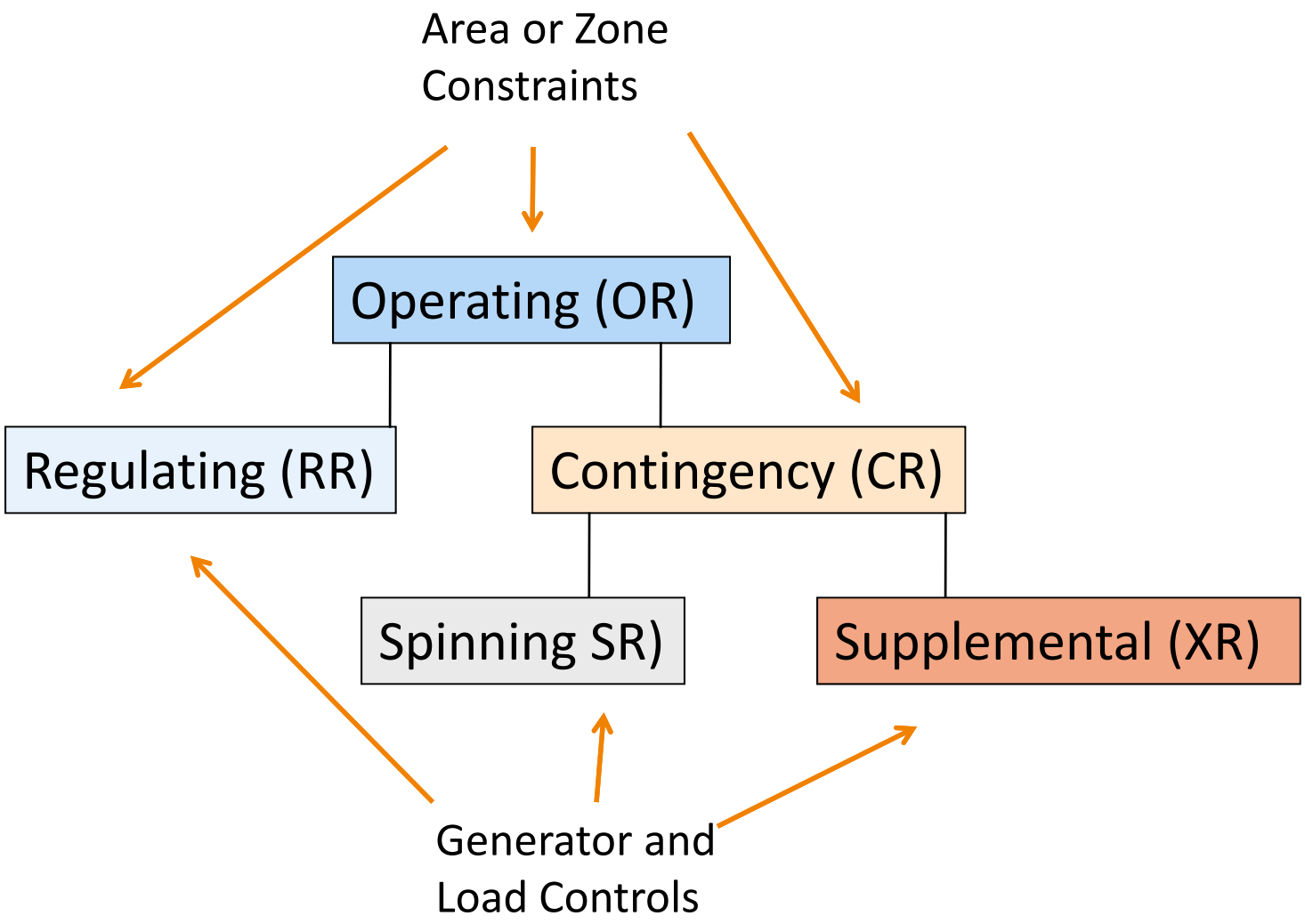
RR+ + SR + XR = OR

RR+ +CR = OR

# Reserve Constraints

- Constraints are usually specified for the aggregate reserve at the area (system) or zone level.
- Usually 3 constraints are observed:
  - Operating Reserve: $OR \geq OR_{Requirement}$
  - Regulating Reserve: $RR^{+}$ , $RR^{-} \geq RR_{Requirement}$
  - Contingency Reserve: $CR \geq CR_{Requirement}$
- These reserve requirements can be specified as Reserve Demand Curves.
- Some systems also need that a percentage of the contingency reserve be spinning: $SR \geq \%CR$

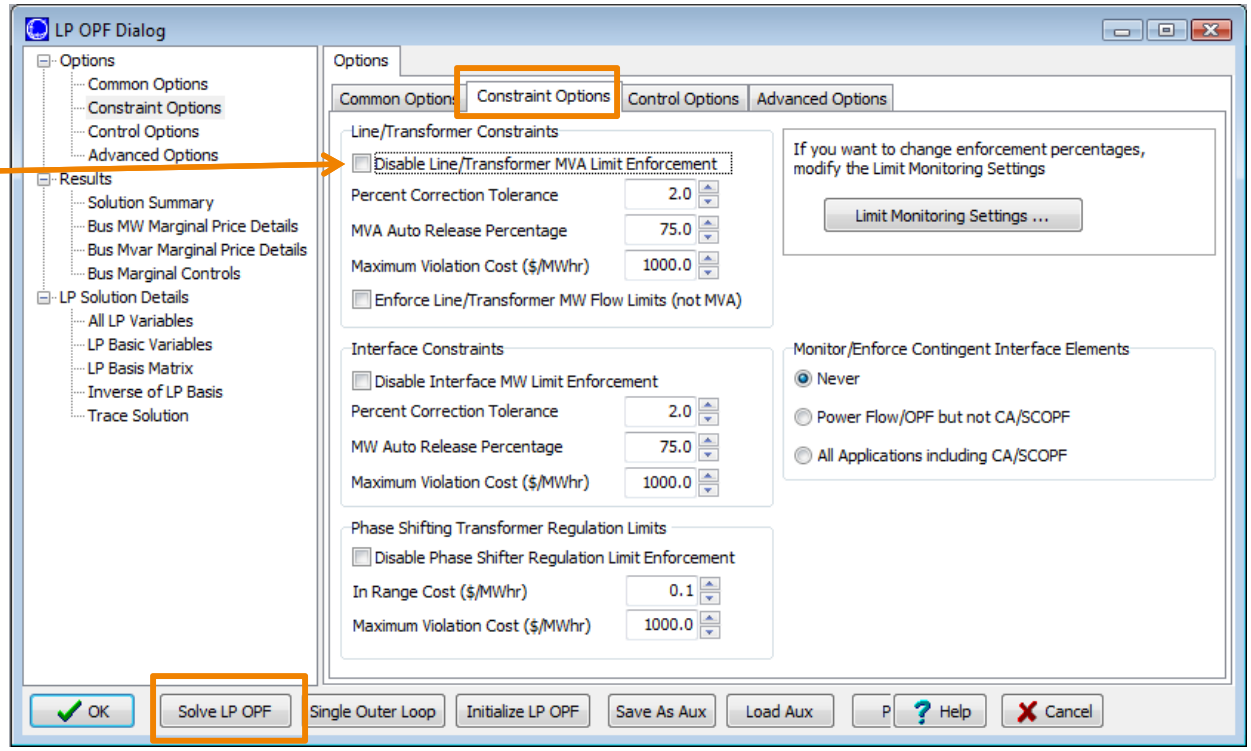
# Reserve Controls and Constraints



# Solving Normal OPF

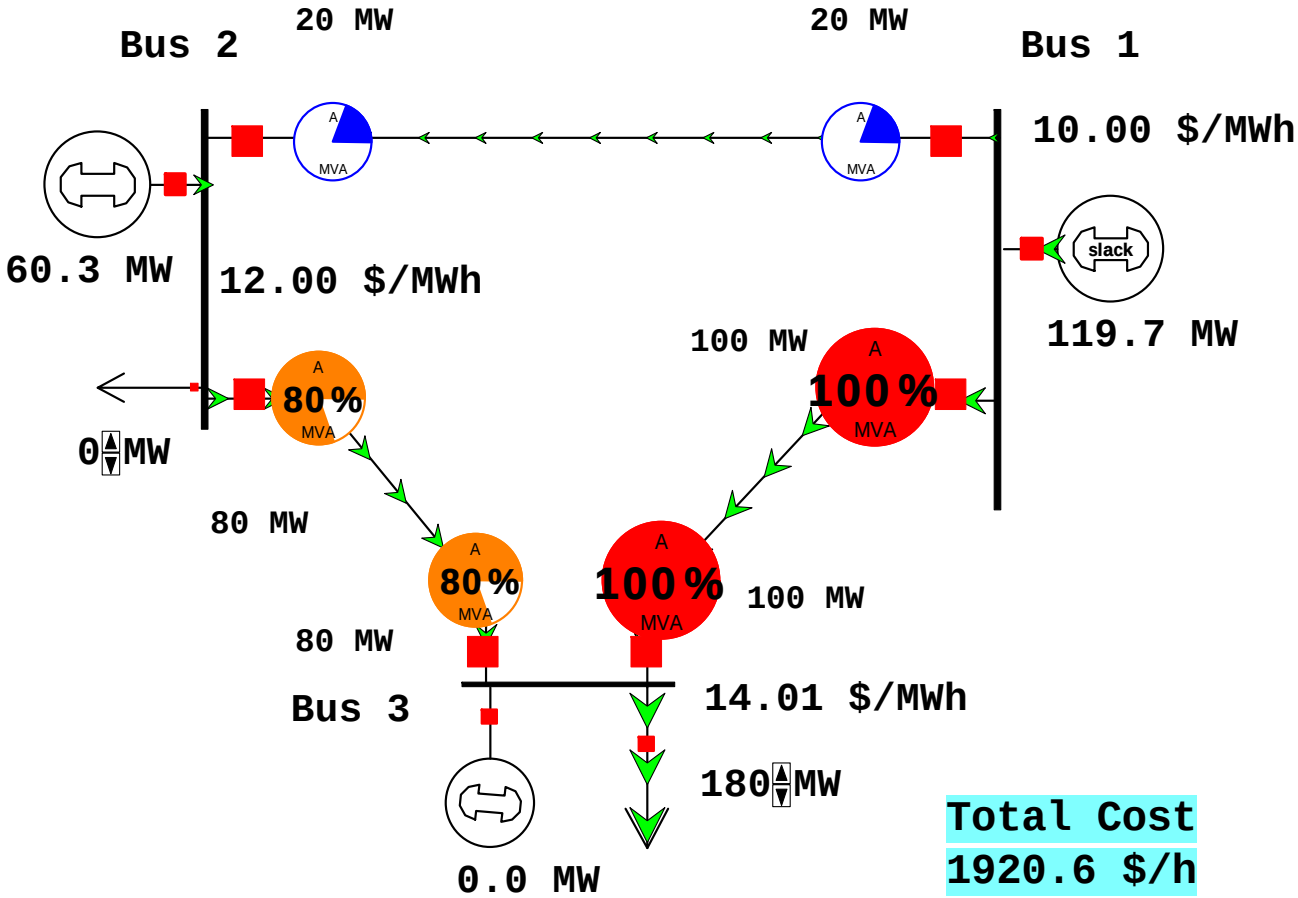
- Open B3LP.pwb and solve OPF Enforcing Line Constraints: **Add Ons → OPF Options and Results → Constraint Options** page

Make sure this is unchecked



# Solving Normal OPF

- Line Limits are now enforced



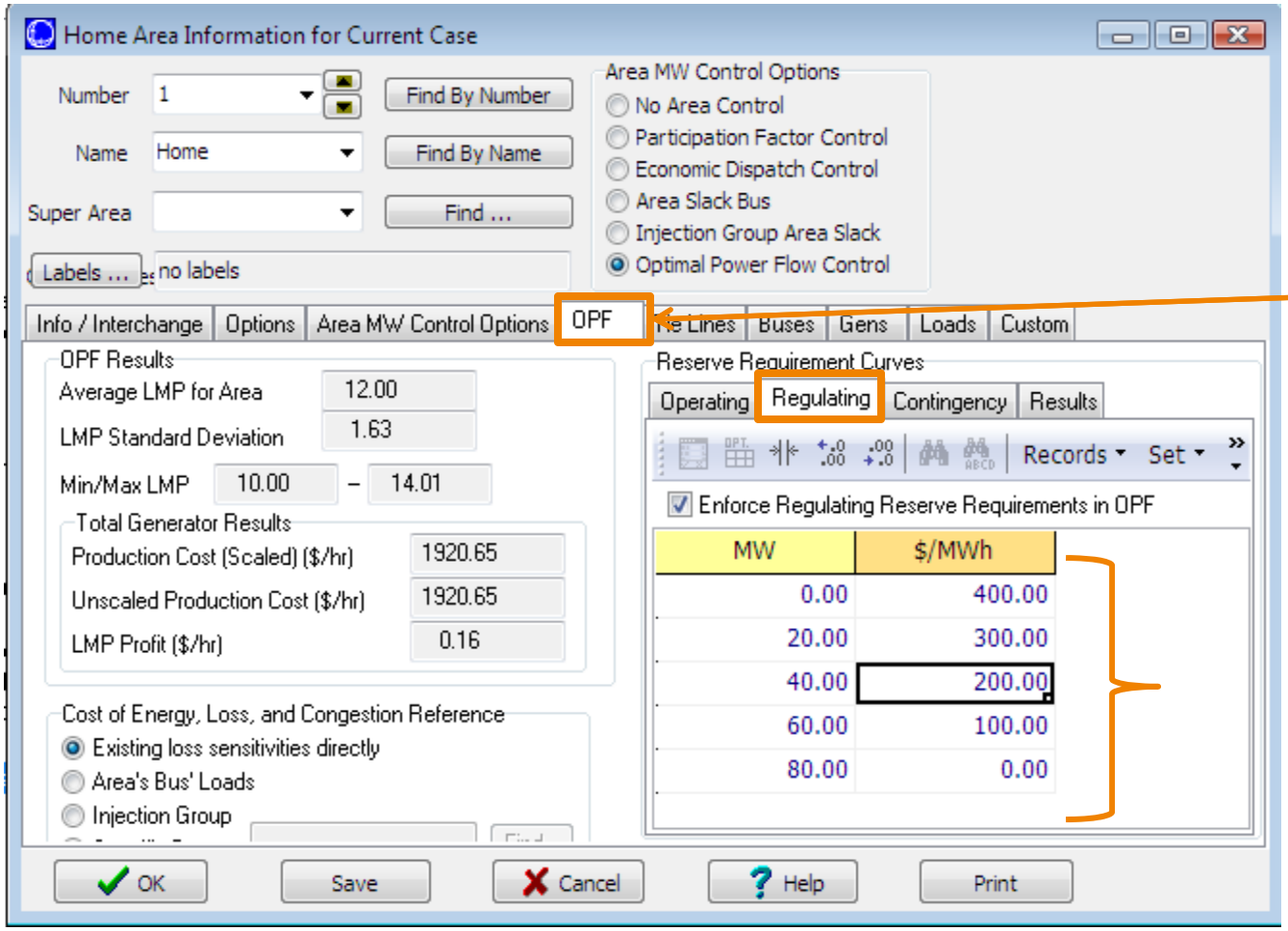
# Regulating Reserve Example

- We'll introduce how Simulator models the reserves market.
- For the sake of clarity, let us assume for now that:
  - Resources include Generators only
  - Generator Controls include Regulating Reserve only
  - Constraints are set at the Area Level only and there are Regulating Constraints only

# Regulating Reserve Example

- The following will be demonstrated later on:
  - Spinning and Supplemental reserve controls
  - Contingency and Operation constraints
  - Zonal constraints
- Right Click anywhere on the Diagram and select **Area Information Dialog**.
  - Go to the **OPF Page** → **Regulating Page**

# Area Regulating Reserve Demand

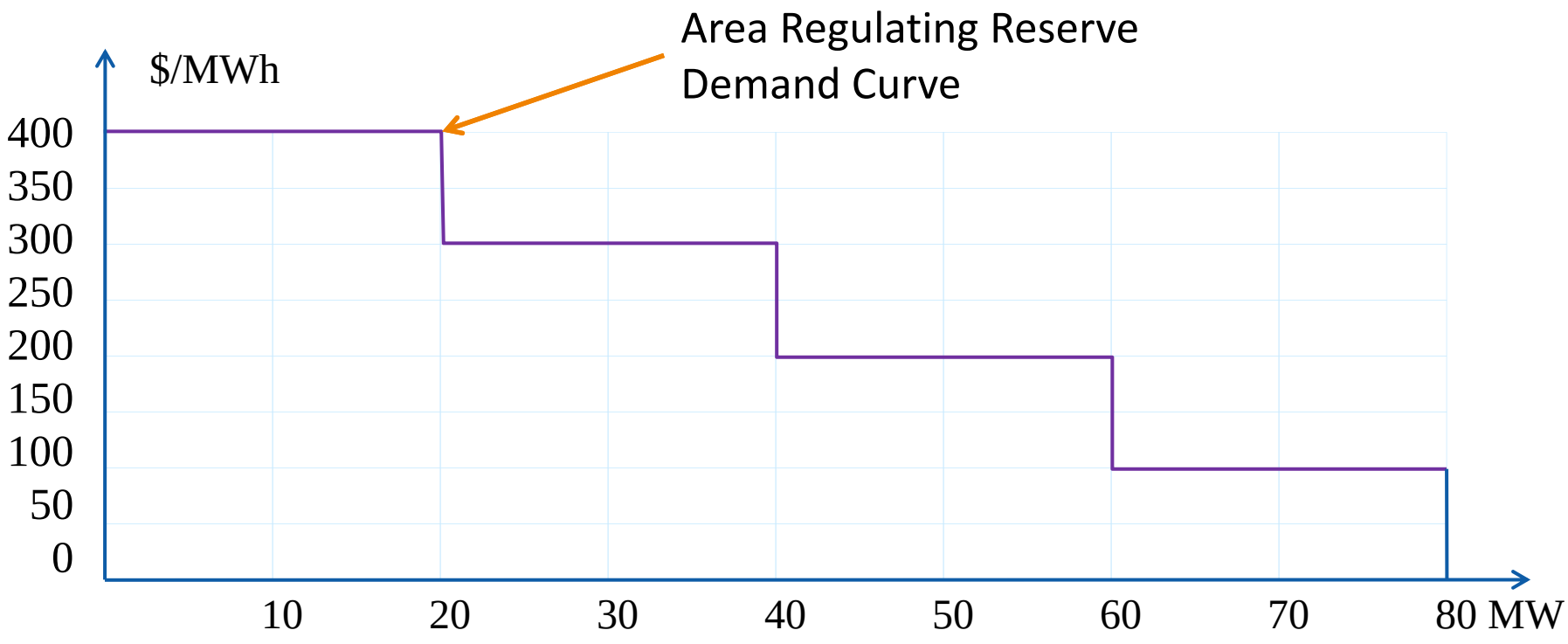



OPF page shows OPF results and to define reserve benefit curves

Define demand curves for **Area Regulating Reserve**. These are positive, descending values.

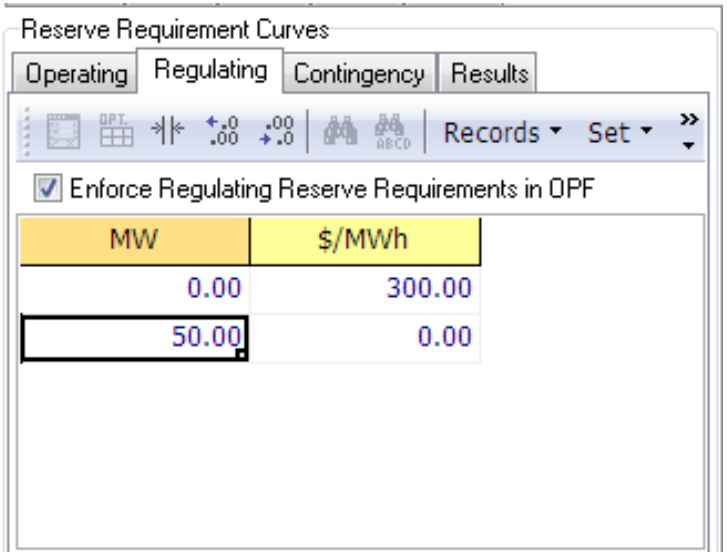
Click OK

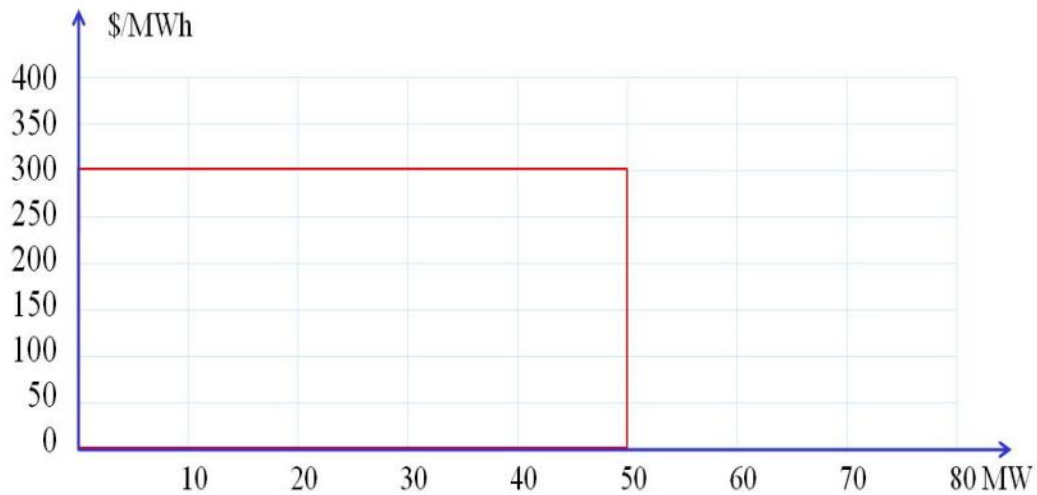
# Area Regulating Reserve Demand



# Area Regulating Reserve Demand

- Note: sometimes we want to model a single value for the Area Regulating Reserve Constraint.
  - For instance, suppose reserve is valued at $300/MWh, and there is a Reserve Requirement of 50MW.



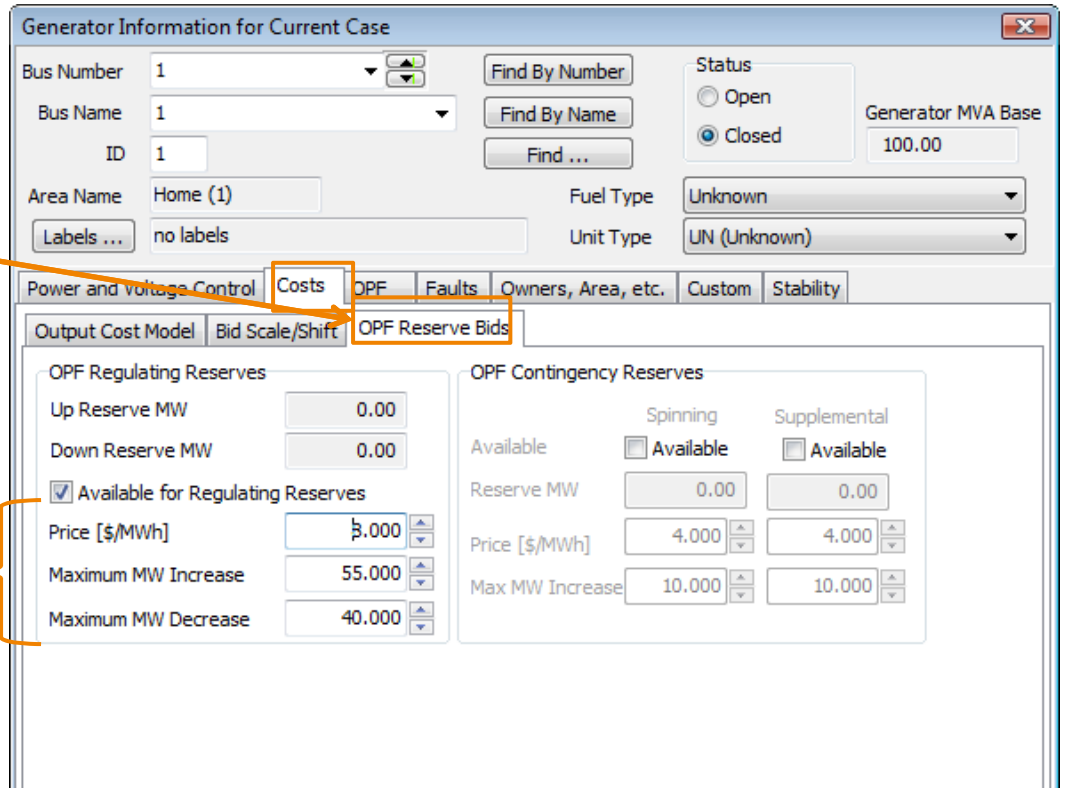



# Generator Reserve Controls

- Right click on Gen 1 and open the information dialog. Go to the **Cost** page, **OPF Reserve Bids** subpage.

OPF Reserve Bids page shows OPF results and to define reserve bids.

Set up corresponding values for price, maximum MW Increase and Decrease. These are limits for Regulation Reserve Up and Down Controls



# Generator Reserve Controls

- Click OK.
- For Gen 2, set up Regulation Reserve at 7.5 $/MWh, a Maximum Regulation Up Limit of 75 MW and Maximum Regulation Down Limit of 60 MW.
- Generator 3 remains not Available for Regulation Reserve.
- Open **Add Ons** → **OPF Case Info** → **OPF Reserves**. Go to the **Generators** page to see the **Generator Case Information** for generator reserve controls.

# Generator Reserve Controls

Generator overall limits including regulation limits

Generator Reserve Control Prices

Generators | Loads | Areas | Zones | Super Areas

| | Number of Bus | Name of Bus | ID | REG Avail. | SPN Avail. | SUP Avail. | Min MW | Gen MW | REG MW Up | REG MW Down | SPN MW Up | SUP MW Up | Max MW | REG Max Up | REG Max Down | SPN Max | SUP Max | REG Price | SPN Price | SUP Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | 1 | YES | NO | NO | 0.00 | 119.68 | 0.00 | 0.00 | 0.00 | 0.00 | 400.00 | 55.00 | 40.00 | 10.00 | 10.00 | 8.00 | 4.00 | 4.00 |
| 2 | 2 | 2 | 1 | YES | NO | NO | 0.00 | 60.30 | 0.00 | 0.00 | 0.00 | 0.00 | 400.00 | 75.00 | 60.00 | 10.00 | 10.00 | 7.50 | 4.00 | 4.00 |
| 3 | 3 | 3 | 1 | NO | NO | NO | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 400.00 | 10.00 | 10.00 | 10.00 | 10.00 | 5.00 | 4.00 | 4.00 |

Generator reserve controls availability. Gens 1 and 2 available for regulation reserve

Generator reserve related output fields (Initially all zero except energy dispatch)

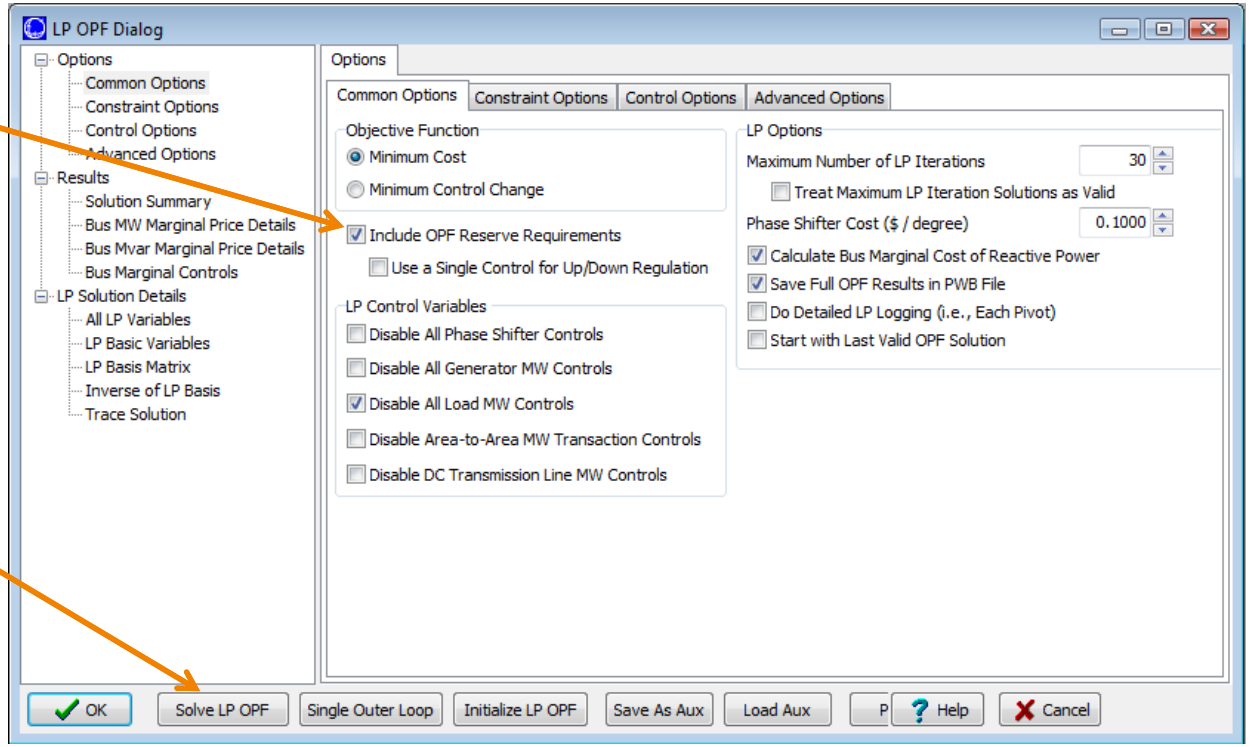
Generator reserve control Limits

# OPF with Regulating Reserves

- Go to **Add Ons** → **OPF Options and Results**

Check OPF Reserves Option. This solves the LP-OPF including reserve controls and constraints

Solve LP OPF Including Reserves



# OPF with Regulating Reserves

- Recall that for this example we consider Regulating Reserve only. Simultaneous optimization of Operating and Contingency reserves will be covered later on.
- This LP problem thus consists in maximizing:

Total Surplus = Up Regulation Reserve Surplus
+ Down Regulation Reserve Surplus
– Total Generation Operating Cost
– Up Regulation Reserve Cost
– Down Regulation Reserve Cost

# OPF with Regulating Reserves

- The control variables are:
  - $P_1,\ P_2,\ P_3$ (Generator MW Output)
  - $P_1^{RR+},\ P_2^{RR+}$ (Gen Up Regulation Reserve)
  - $P_1^{RR-},\ P_2^{RR-}$ (Gen Down Regulation Reserve)
  - $A_1^{RR+}$ (Area Up Regulation Reserve)
  - $A_1^{RR-}$ (Area Down Regulation Reserve)

# OPF with Regulating Reserves

- And the constraints are:

| | |
|---|---|
| $P_1 + P_2 + P_3 = P_{\text{LOAD}}$ | (Area Power Balance) |
| | (System has no losses) |
| $S_{jk} \leq S_{jk}^{max}$ | (Limit Thermal (MVA) Limits) |
| $P_1^{RR+} + P_2^{RR+} = A_1^{RR+}$ | (Up Reg. Reserve Balance) |
| $P_1^{RR-} + P_2^{RR-} = A_1^{RR-}$ | (Down Reg. Reserve Balance) |
| $P_i + P_i^{RR+} \leq P_i^{max}$ | (Generator Max Limits) |
| $P_i^{min} \leq P_i - P_i^{RR-}$ | (Generator Min Limits) |

# OPF with Regulating Reserves

- Check the LP Solution: Go to **OPF Case Info** → **OPF Reserves** → **Generators**

OPF Reserve Requirements Results | OPF Generators

Records Geo Set Columns Opti

Generators | Loads | Areas | Zones | Super Areas

| | Number of Bus | Name of Bus | ID | REG Avail. | SPN Avail. | SUP Avail. | Min MW | Gen MW | REG MW Up | REG MW Down | SPN MW Up | SUP MW Up | Max MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | 1 | YES | NO | NO | 0.00 | 119.67 | 5.00 | 20.00 | 0.00 | 0.00 | 400.00 |
| 2 | 2 | 2 | 1 | YES | NO | NO | 0.00 | 60.35 | 75.00 | 60.00 | 0.00 | 0.00 | 400.00 |
| 3 | 3 | 3 | 1 | NO | NO | NO | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 400.00 |

MW values show the cleared regulation reserve

# OPF with Regulating Reserves

- Go to **LP Solution Details** Page

Solution values of LP variables

Note that all constraints are satisfied

LP Solution Details

All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Basis | Trace Solution

Records Set Columns

| | ID | Org. Value | Value | Delta Value | BasicVar | NonBasicVar |
|---|---|---|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 119.682 | 119.834 | 0.152 | 4 | 0 |
| 2 | Gen 1 #1 REG MW Up Control | 0.000 | 5.000 | 5.000 | 2 | 0 |
| 3 | Gen 1 #1 REG MW Down Control | 0.000 | 20.000 | 20.000 | 3 | 0 |
| 4 | Gen 2 #1 MW Control | 60.304 | 60.000 | -0.304 | 5 | 0 |
| 5 | Gen 2 #1 REG MW Up Control | 0.000 | 75.000 | 75.000 | 0 | 5 |
| 6 | Gen 2 #1 REG MW Down Control | 0.000 | 60.000 | 60.000 | 0 | 6 |
| 7 | Gen 3 #1 MW Control | 0.000 | 0.152 | 0.152 | 1 | 0 |
| 8 | Area Home REG MW Up Control | 0.000 | 80.000 | 80.000 | 0 | 8 |
| 9 | Area Home REG MW Down Control | 0.000 | 80.000 | 80.000 | 0 | 9 |
| 10 | Slack-Area Home | 0.000 | 0.000 | 0.000 | 0 | 1 |
| 11 | Slack-Area Home REG Up | 0.000 | 0.000 | 0.000 | 0 | 2 |
| 12 | Slack-Area Home REG Down | 0.000 | 0.000 | 0.000 | 0 | 3 |
| 13 | Slack-Line 1 TO 3 CKT 1 | -20.119 | 0.000 | 20.119 | 0 | 7 |
| 14 | Slack-Gen 2 #1 Min | -60.000 | 0.000 | 60.000 | 0 | 4 |

Slack variables for binding constraints

# OPF with Regulating Reserves

- Go to **Area Information Dialog, OPF** page
- In **Reserve Requirement Curves** select **Results** page

All the available reserve is cleared

$REG^+$ :
G1: $5 \times 8 = 40$
G2: $75 \times 7.5 = 562.5$

$REG^-$ :
Gen1: $20 \times 8 = 160$
Gen 2: $60 \times 7.5 = 450$

Reserve Requirement Curves

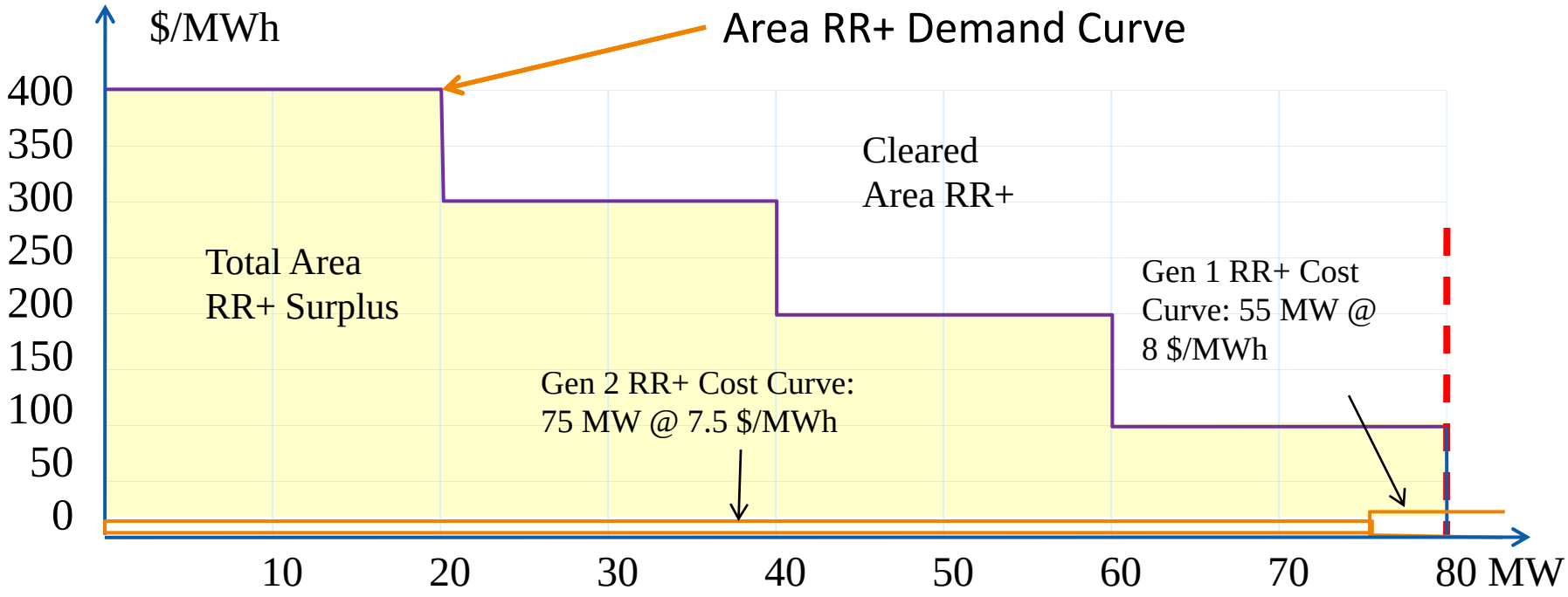
Operating | Regulating | Contingency | Results

| | REG + | REG-- | SPN | SUP | CTG | OPR |
|---|---|---|---|---|---|---|
| Enforce | YES | YES | NO | NO | NO | NO |
| Cleared MW | 80.00 | 80.00 | 0.00 | 0.00 | 0.00 | 80.00 |
| Max Reserve MW | 130.00 | 100.00 | 0.00 | 0.00 | 0.00 | 130.00 |
| Hourly Cost $/hr | 602.50 | 610.00 | 0.00 | 0.00 | 0.00 | 602.50 |
| Price $/MWh | 8.00 | 8.00 | | | 0.00 | 0.00 |
| Hourly Benefit $/hr | 20000.00 | 20000.00 | | | 0.00 | 0.00 |

Benefit is obtained integrating the Area Regulation Demand Curve :
$20\times400+ 20\times300+ 20\times200+20\times100 = 20000$

# OPF with Regulating Reserves

- In this example, there is enough reserve to meet the highest MW reserve requirement. The price of regulating reserve is equal to the incremental cost of 8 $/MWh



# Effect of Generator Limits

- Decrease Gen 1 limit from 400 to 100MW and solve LP:

Gen 1 reduces 25 MW in order to make room for "more valuable" 5 MW of reserve.

Gen 1 output reduction causes Gen 2 to increase its energy output

Max MW Limit of Gen 1 becomes a binding constraint

LP Solution Details

All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Basis | Trace Solution

Records Set Columns

| | ID | Org. Value | Value | Delta Value | BasicVar | NonBasicVar |
|---|---|---|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 100.000 | 95.000 | -5.000 | 1 | 0 |
| 2 | Gen 1 #1 REG MW Up Control | 5.000 | 5.000 | -0.000 | 2 | 0 |
| 3 | Gen 1 #1 REG MW Down Control | 20.000 | 20.000 | -0.000 | 3 | 0 |
| 4 | Gen 2 #1 MW Control | 69.991 | 85.163 | 15.172 | 4 | 0 |
| 5 | Gen 2 #1 REG MW Up Control | 75.000 | 75.000 | 0.000 | 0 | 5 |
| 6 | Gen 2 #1 REG MW Down Control | 60.000 | 60.000 | 0.000 | 0 | 6 |
| 7 | Gen 3 #1 MW Control | 10.143 | 0.000 | -10.143 | 0 | 7 |
| 8 | Area Home REG MW Up Control | 80.000 | 80.000 | 0.000 | 0 | 8 |
| 9 | Area Home REG MW Down Control | 80.000 | 80.000 | 0.000 | 0 | 9 |
| 10 | Slack-Area Home | 0.000 | 0.000 | 0.000 | 0 | 1 |
| 11 | Slack-Area Home REG Up | 0.000 | 0.000 | 0.000 | 0 | 2 |
| 12 | Slack-Area Home REG Down | 0.000 | 0.000 | 0.000 | 0 | 3 |
| 13 | Slack-Gen 1 #1 Max | -5.030 | 0.000 | 5.030 | 0 | 4 |

# Effect of Scarce Reserve

- Return Gen1 Limit to 400 MW.
- In order to model scarce reserves, assume available reserves of 35MW of regulation reserve up and 25 MW of regulation reserve down for each generator.

| REG Max Up | REG Max Down | SPN Max | SUP Max | REG Price | SPN Price | SUP Price |
|---|---|---|---|---|---|---|
| 35.00 | 25.00 | 120.00 | 0.00 | 8.00 | 6.00 | 5.00 |
| 35.00 | 25.00 | 50.00 | 48.00 | 7.50 | 4.00 | 5.20 |
| 10.00 | 10.00 | 50.00 | 36.00 | 5.00 | 4.50 | 3.70 |

- Solve LP-OPF

# Effect of Scarce Reserve

Gens 1 and 2 dispatch reserve depending on the demand curve.

LP Solution Details

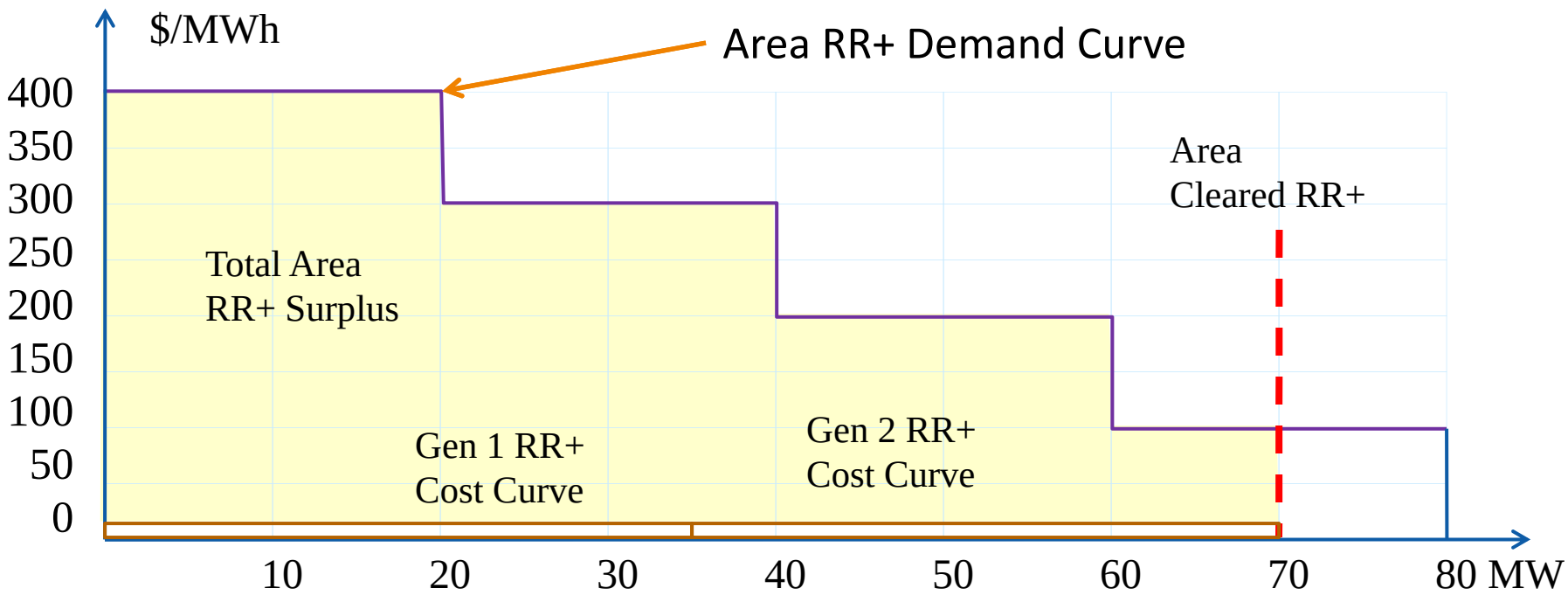
All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Basis | Trace Solution

Records Set Columns

| | ID | Org. Value | Value | Delta Value | BasicVar | NonBasicVar |
|---|---|---|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 95.000 | 137.416 | 42.416 | 4 | 0 |
| 2 | Gen 1 #1 REG MW Up Control | 5.000 | 35.000 | 30.000 | 0 | 2 |
| 3 | Gen 1 #1 REG MW Down Control | 20.000 | 25.000 | 5.000 | 0 | 3 |
| 4 | Gen 2 #1 MW Control | 85.163 | 25.000 | -60.163 | 5 | 0 |
| 5 | Gen 2 #1 REG MW Up Control | 75.000 | 35.000 | -40.000 | 0 | 5 |
| 6 | Gen 2 #1 REG MW Down Control | 60.000 | 25.000 | -35.000 | 0 | 6 |
| 7 | Gen 3 #1 MW Control | 0.000 | 17.735 | 17.735 | 1 | 0 |
| 8 | Area Home REG MW Up Control | 80.000 | 70.000 | -10.000 | 2 | 0 |
| 9 | Area Home REG MW Down Control | 80.000 | 50.000 | -30.000 | 3 | 0 |
| 10 | Slack-Area Home | 0.000 | 0.000 | 0.000 | 0 | 1 |
| 11 | Slack-Area Home REG Up | 0.000 | 0.000 | 0.000 | 0 | 8 |
| 12 | Slack-Area Home REG Down | 0.000 | 0.000 | 0.000 | 0 | 9 |
| 13 | Slack-Line 1 TO 3 CKT 1 | -20.180 | 0.000 | 20.180 | 0 | 7 |
| 14 | Slack-Gen 2 #1 Min | -25.000 | 0.000 | 25.000 | 0 | 4 |

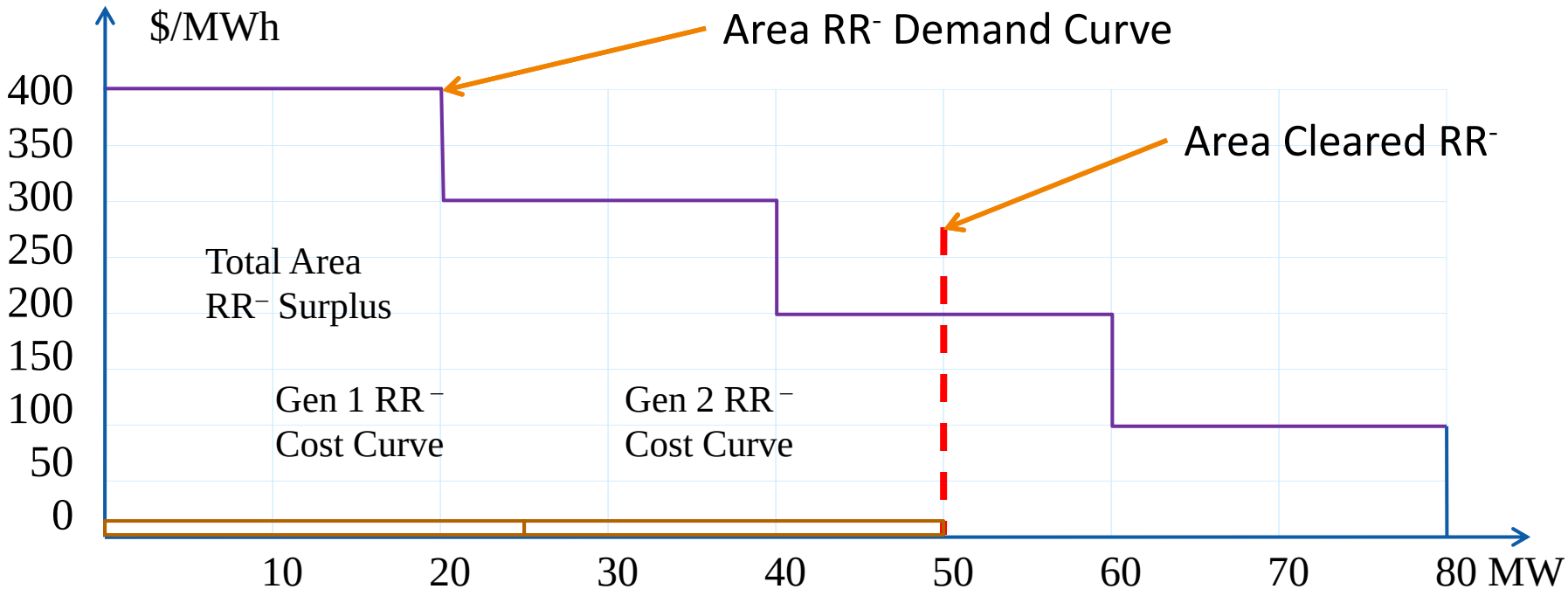
# Effect of Scarce Reserve

- For RR$^+$, there is no intersection of supply and demand due to reserve scarcity. The price is equal to the demand curve at the total amount of reserve, i.e., 100 $/MWh



# Effect of Scarce Reserve

- For RR⁻, the price is higher, since there is less reserve available.



# Area Contingency Reserves

- Includes spinning and supplemental reserve resource controls.
- LP OPF with contingency (and regulation) reserves maximizes:

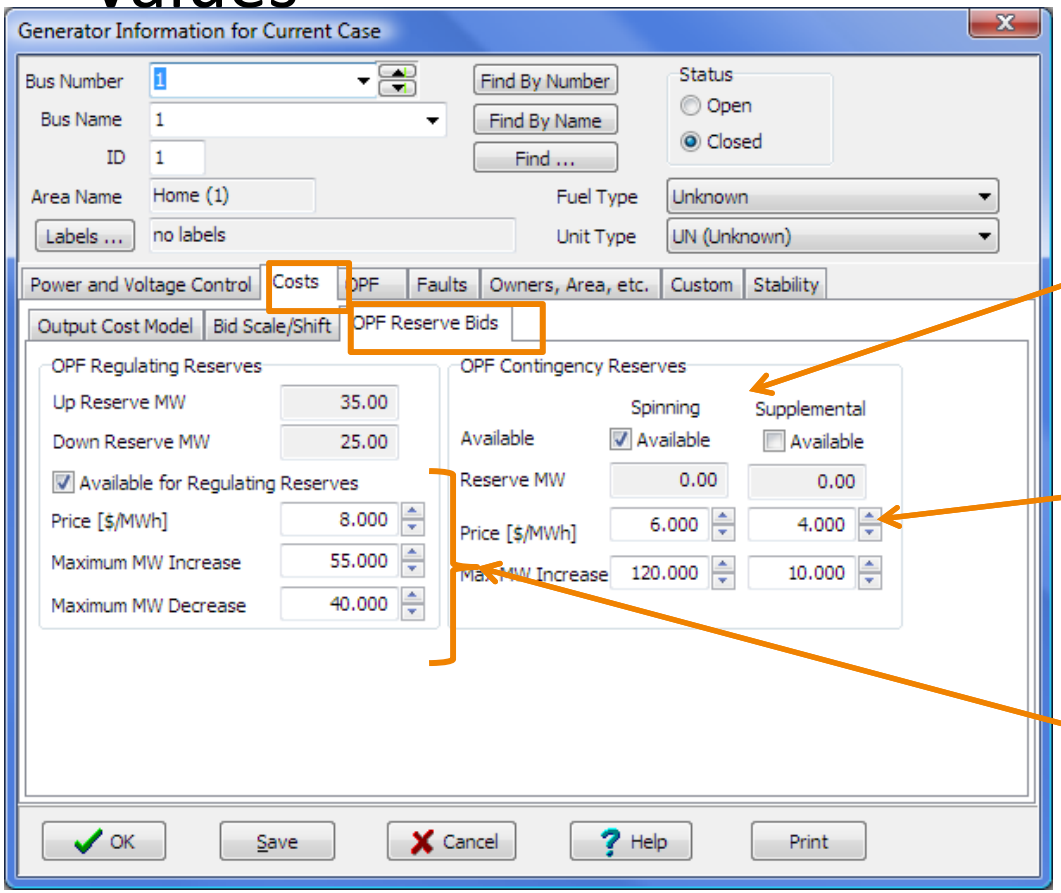
Total Surplus = Up Regulation Reserve Surplus
+ Down Regulation Reserve Surplus
+ Contingency Reserve Surplus
– Total Generation Operating Cost
– Up Regulation Reserve Cost
– Down Regulation Reserve Cost
– Spinning Reserve Cost
– Supplemental Reserve Cost

# Area Contingency Reserves

- Assume that Gen 1 and Gen 2 are available for spinning reserve and Gen 2 and Gen 3 are available for supplemental reserve. The control variables are:
  - $P_1$, $P_2$, $P_3$ (Generator MW Output)
  - $P_1^{RR+}$, $P_2^{RR+}$ (Gen Up Regulation Reserve)
  - $P_1^{RR-}$, $P_2^{RR-}$ (Gen Down Regulation Reserve)
  - $P_1^{SR}$, $P_2^{SR}$ (Gen Spinning Reserve)
  - $P_2^{XR}$, $P_3^{XR}$ (Gen Supplemental Reserve)
  - $A_1^{RR+}$ (Area Up Regulation Reserve)
  - $A_1^{RR-}$ (Area Down Regulation Reserve)
  - $A_1^{CR}$ (Area Contingency Reserve)

# Generator Contingency Reserves

- Open Gen1 Dialog to set up Contingency Reserve Values




Spinning and Supplemental Reserve Control Availability

Spinning and Supplemental Limits and Prices

Reset Regulation Reserve Limits to the original values

# Generator Contingency Reserves

- Set up Gen Reserve values so they look as follows (same as in Slide 17 but with spinning and supplemental control enabled)

Generators | Loads | Areas | Zones | Super Areas

| | Number of Bus | Name of Bus | ID | REG Avail. | SPN Avail. | SUP Avail | Min MW | Gen MW | REG MW Up | REG MW Down | SPN MW Up | SUP MW Up | Max MW | REG Max Up | REG Max Down | SPN Max | SUP Max | REG Price | SPN Price | SUP Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | 1 | YES | YES | NO | 0.00 | 137.42 | 35.00 | 25.00 | 0.00 | 0.00 | 400.00 | 55.00 | 40.00 | 120.00 | 10.00 | 8.00 | 6.00 | 4.00 |
| 2 | 2 | 2 | 1 | YES | YES | YES | 0.00 | 25.00 | 35.00 | 25.00 | 0.00 | 0.00 | 400.00 | 75.00 | 60.00 | 50.00 | 48.00 | 7.50 | 4.00 | 5.20 |
| 3 | 3 | 3 | 1 | NO | YES | YES | 0.00 | 17.74 | 0.00 | 0.00 | 0.00 | 0.00 | 400.00 | 10.00 | 10.00 | 50.00 | 36.00 | 5.00 | 4.50 | 3.70 |

| REG Avail. | SPN Avail. | SUP Avail. |
|---|---|---|
| YES | YES | NO |
| YES | YES | YES |
| NO | YES | YES |

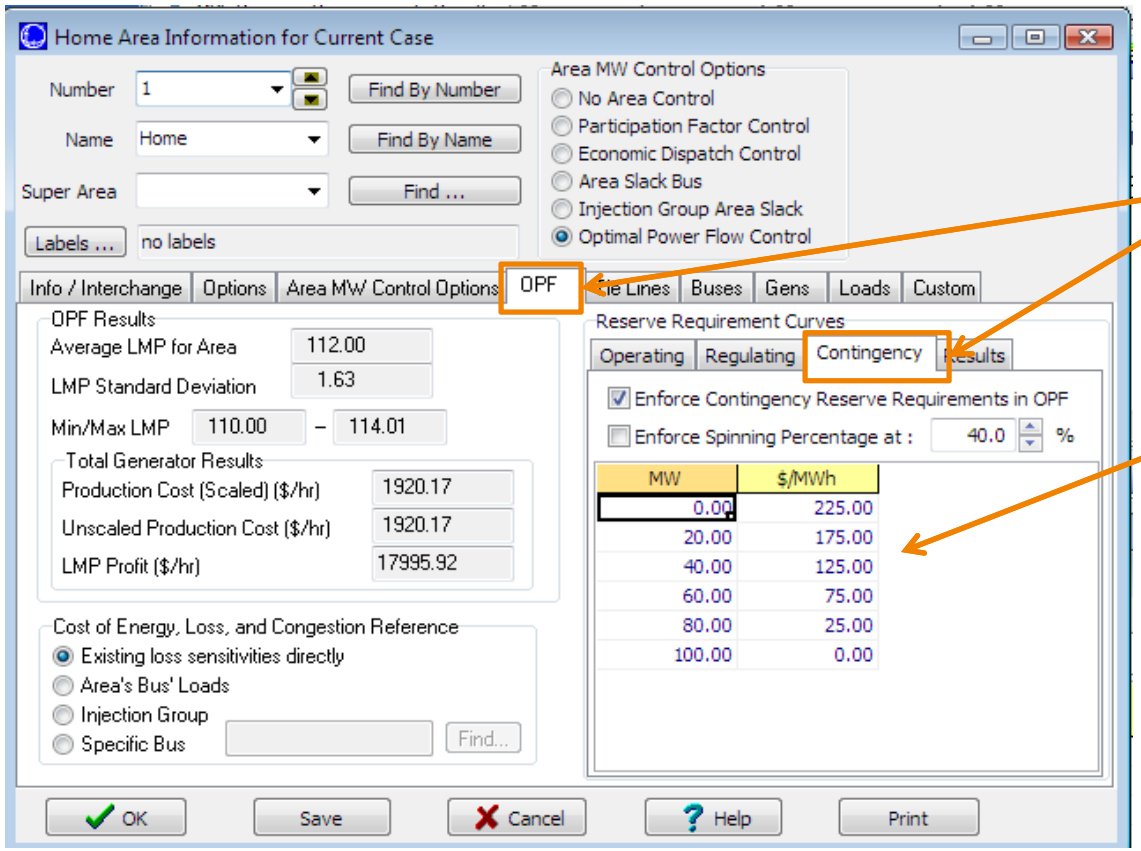
Reserve Control Availability

| REG Max Up | REG Max Down | SPN Max | SUP Max | REG Price | SPN Price | SUP Price |
|---|---|---|---|---|---|---|
| 55.00 | 40.00 | 120.00 | 0.00 | 8.00 | 6.00 | 5.00 |
| 75.00 | 60.00 | 50.00 | 48.00 | 7.50 | 4.00 | 5.20 |
| 10.00 | 10.00 | 50.00 | 36.00 | 5.00 | 4.50 | 3.70 |

Available MW and prices of reserve controls

# Area Contingency Reserve Demand

- Set up the Area Contingency Reserve demand curve in the **Area Information Dialog**




OPF page used to show results and to define reserve benefit curves

Define demand curve for Area Contingency Reserve. These are positive, descending values.

Click OK and **Solve the LP-OPF with Reserves**

# Contingency Reserve OPF Solution

If available for reserves, generators have their corresponding controls as LP variables

The Area Contingency reserve constraint is added

Since Generator Limits are 400MW, the contingency reserve requirement is met

LP Solution Details

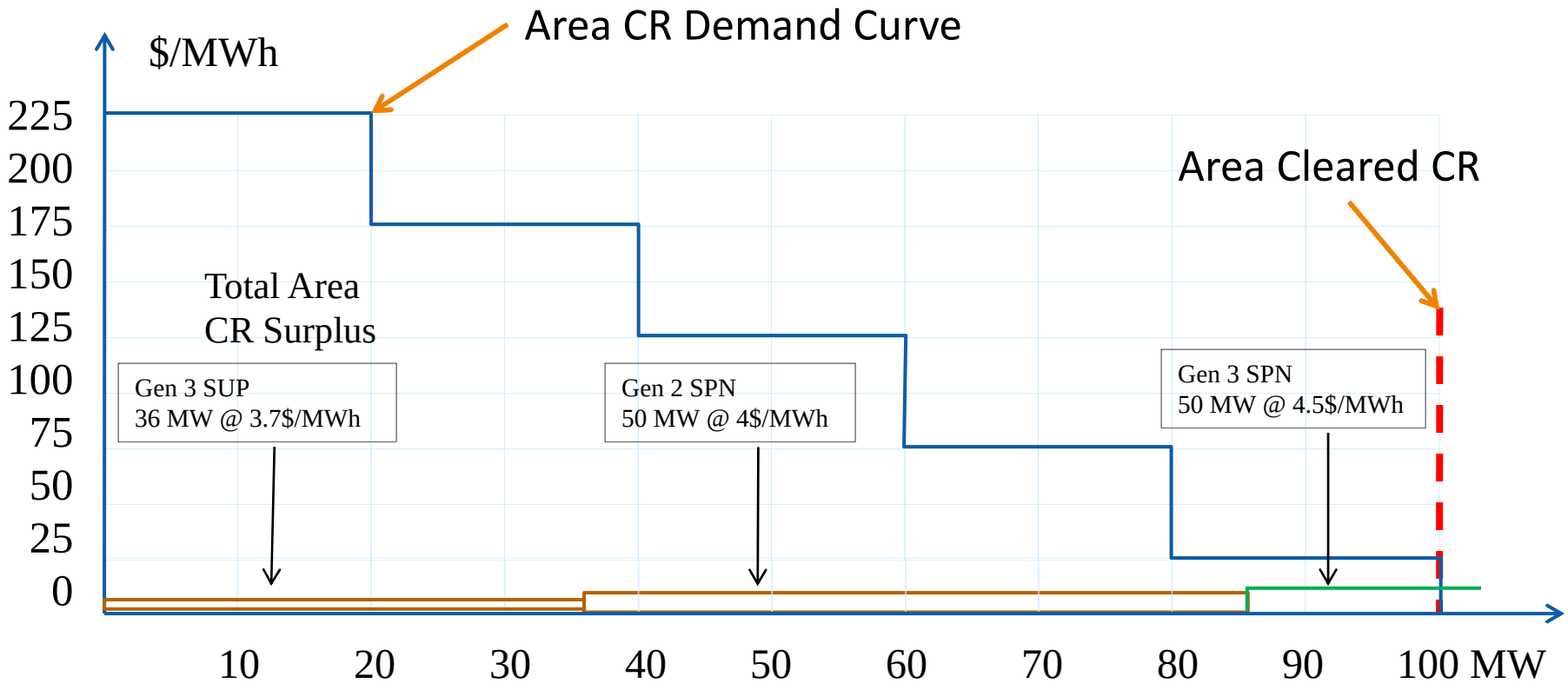
All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Basis | Trace Solution

Records Set Columns

| | ID | Org. Value | Value | Delta Value | BasicVar | NonBasicVar | Cost(Down) |
|---|---|---|---|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 137.416 | 119.704 | -17.712 | 1 | 0 | 10.00 |
| 2 | Gen 1 #1 REG MW Up Control | 35.000 | 5.000 | -30.000 | 2 | 0 | 8.00 |
| 3 | Gen 1 #1 REG MW Down Control | 25.000 | 20.000 | -5.000 | 3 | 0 | 8.00 |
| 4 | Gen 1 #1 SPN MW Control | 0.000 | 0.000 | 0.000 | 0 | 4 | At Min |
| 5 | Gen 2 #1 MW Control | 25.000 | 60.296 | 35.296 | 5 | 0 | 12.00 |
| 6 | Gen 2 #1 REG MW Up Control | 35.000 | 75.000 | 40.000 | 0 | 2 | 7.50 |
| 7 | Gen 2 #1 REG MW Down Control | 25.000 | 60.000 | 35.000 | 0 | 3 | 7.50 |
| 8 | Gen 2 #1 SPN MW Control | 0.000 | 50.000 | 50.000 | 0 | 8 | 4.00 |
| 9 | Gen 2 #1 SUP MW Control | 0.000 | 0.000 | 0.000 | 0 | 9 | At Min |
| 10 | Gen 3 #1 MW Control | 17.735 | 0.000 | -17.735 | 0 | 5 | At Min |
| 11 | Gen 3 #1 SPN MW Control | 0.000 | 14.000 | 14.000 | 4 | 0 | 4.50 |
| 12 | Gen 3 #1 SUP MW Control | 0.000 | 36.000 | 36.000 | 0 | 12 | 3.70 |
| 13 | Area Home REG MW Up Control | 70.000 | 80.000 | 10.000 | 0 | 6 | -100.00 |
| 14 | Area Home REG MW Down Control | 50.000 | 80.000 | 30.000 | 0 | 7 | -100.00 |
| 15 | Area Home CTG MW Control | 0.000 | 100.000 | 100.000 | 0 | 11 | -25.00 |
| 16 | Slack-Area Home | 0.000 | 0.000 | 0.000 | 0 | 10 | At Min |
| 17 | Slack-Area Home REG Up | 0.000 | 0.000 | 0.000 | 0 | 13 | At Min |
| 18 | Slack-Area Home REG Down | 0.000 | 0.000 | 0.000 | 0 | 14 | At Min |
| 19 | Slack-Area Home CTG | 0.000 | 0.000 | 0.000 | 0 | 15 | At Min |
| 20 | Slack-Line 1 TO 3 CKT 1 | 0.000 | 0.000 | 0.000 | 0 | 1 | At Min |

# Contingency Reserve Pricing

- The reserve requirement is met and hence the marginal price of contingency reserve is equal to 4.5 $/MWh



# Contingency Reserve Pricing

- The LMP pricing details are as follows:

Results

Solution Summary | Bus MW Marginal Price Details | Bus Mvar Marginal Price Details | Bus Marginal Controls

Records Geo Set Columns f(x) Options

| | Number | Name | Area Name | MW Marg. Cost | Energy $/MWh | Congestion $/MWh | Losses $/MWh | Area 1 MW Constraint | Area 1 Area REG ResMWUp Constraint | Area 1 Area REG ResMWDown Constraint | Area 1 Area CTG ResMW Constraint | Line from 1 to 3 ckt. 1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | Home | 10.00 | 10.00 | 0.00 | 0.00 | 10.00 | 8.00 | 8.00 | 4.50 | 0.00 |
| 2 | 2 | 2 | Home | 12.00 | 10.00 | 2.00 | 0.00 | 10.00 | 8.00 | 8.00 | 4.50 | 2.00 |
| 3 | 3 | 3 | Home | 14.01 | 10.00 | 4.00 | 0.00 | 10.00 | 8.00 | 8.00 | 4.50 | 4.00 |

Bus LMP

Marginal Cost of Enforcing Area RR+ Constraint

Marginal Cost of Enforcing Area CR Constraint

# Area Operating Reserves

- Objective function becomes:

Total Surplus = Up Regulation Reserve Surplus
+ Down Regulation Reserve Surplus
+ Contingency Reserve Surplus
+ Operating Reserve Surplus
– Total Generation Operating Cost
– Up Regulation Reserve Cost
– Down Regulation Reserve Cost
– Spinning Reserve Cost
– Supplemental Reserve Cost

# Area Operating Reserve

- No new resource controls are included beyond regulating, spinning and supplemental reserve, but one LP variable is added for the Area Operation Reserve
  - $P_1,\ P_2,\ P_3$ (Generator MW Output)
  - $P_1^{RR+},\ P_2^{RR+}$ (Gen Up Regulation Reserve)
  - $P_1^{RR-},\ P_2^{RR-}$ (Gen Down Regulation Reserve)
  - $P_1^{SR},\ P_2^{SR}$ (Gen Spinning Reserve)
  - $P_2^{XR},\ P_3^{XR}$ (Gen Supplemental Reserve)
  - $A_1^{RR+}$ (Area Up Regulation Reserve)
  - $A_1^{RR-}$ (Area Down Regulation Reserve)
  - $A_1^{CR}$ (Area Contingency Reserve)
  - $A_1^{OR}$ (Area Operation Reserve)

# Area Operating Reserves

The constraints are now:

$P_1 + P_2 + P_3 = P_{\text{LOAD}}$ (Power Balance)

$S_{jk} \leq S_{jk}^{max}$ (Line Limits)

$P_1^{RR+} + P_2^{RR+} = A_1^{RR+}$ (RR+ Balance)

$P_1^{RR-} + P_2^{RR-} = A_1^{RR-}$ (RR– Balance)

$P_1^{SR} + P_2^{SR} + P_2^{XR} + P_3^{SR} + P_3^{XR} = A_1^{CR}$ (CR Balance)

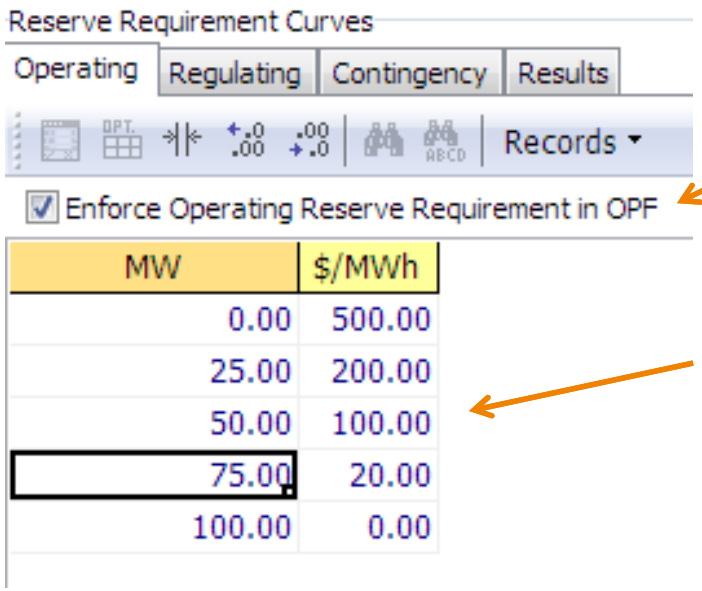
$P_1^{RR+} + P_1^{SR} + P_2^{RR+} + P_2^{SR} + P_2^{XR} + P_3^{SR} + P_3^{XR} = A_1^{OR}$ (OR Balance)

$P_i + P_i^{RR+} + P_i^{SR} + P_i^{XR} \leq P_i^{max}$ (Gen Max Limits)

$P_i^{min} \leq P_i - P_i^{RR-}$ (Gen Min Limits)

# Area Operating Reserve Demand

- Set up operating reserve demand curve in the **Area Information Dialog.**




Area Operating Reserve should be enforced only when Area Regulating Reserve AND Area Contingency Reserve are enforced.

Define demand curve for Area Operating Reserve.

Click OK and
**Solve the LP-OPF with Reserves**

# Operating Reserve OPF Solution

| | ID | Org. Value | Value |
|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 119.704 | 119.852 |
| 2 | Gen 1 #1 REG MW Up Control | 5.000 | 0.000 |
| 3 | Gen 1 #1 REG MW Down Control | 20.000 | 20.000 |
| 4 | Gen 1 #1 SPN MW Control | 0.000 | 0.000 |
| 5 | Gen 2 #1 MW Control | 60.296 | 60.000 |
| 6 | Gen 2 #1 REG MW Up Control | 75.000 | 60.000 |
| 7 | Gen 2 #1 REG MW Down Control | 60.000 | 60.000 |
| 8 | Gen 2 #1 SPN MW Control | 50.000 | 4.000 |
| 9 | Gen 2 #1 SUP MW Control | 0.000 | 0.000 |
| 10 | Gen 3 #1 MW Control | 0.000 | 0.148 |
| 11 | Gen 3 #1 SPN MW Control | 14.000 | 0.000 |
| 12 | Gen 3 #1 SUP MW Control | 36.000 | 36.000 |
| 13 | Area Home OPR MW Control | 0.000 | 100.000 |
| 14 | Area Home REG MW Up Control | 80.000 | 60.000 |
| 15 | Area Home REG MW Down Control | 80.000 | 80.000 |
| 16 | Area Home CTG MW Control | 100.000 | 40.000 |
| 17 | Slack-Area Home | 0.000 | 0.000 |
| 18 | Slack-Area Home OPR | -180.000 | 0.000 |
| 19 | Slack-Area Home REG Up | 0.000 | 0.000 |
| 20 | Slack-Area Home REG Down | 0.000 | 0.000 |
| 21 | Slack-Area Home CTG | 0.000 | 0.000 |
| 22 | Slack-Line 1 TO 3 CKT 1 | -20.116 | 0.000 |
| 23 | Slack-Gen 2 #1 Min | -60.000 | 0.000 |

New Area Operating Reserve LP Variable

Operating reserves value becomes zero when there are more than 100MW of cleared reserve. Thus area contingency reserve decreases from 100 to 40 MW.

# Spinning Percent Constraint

- An additional constraint usually implemented in markets is that the spinning reserve of a zone has to be at least certain percentage, i.e., 40%, of the contingency reserve of that zone.
  - This ensures that enough “local” spinning reserve is available to respond to unexpected events.
- Regarding contingency reserve, in our 3-bus case.
  - Gen1, Gen2, and Gen3 can provide spinning reserve
  - Gen2 and Gen3 can provide supplemental reserve

# Spinning Percent Constraint

- The spinning percent constraint equation is:

$$P_1^{SR} + P_2^{SR} + P_3^{SR} \geq SR^{\%} \times Z_1^{CR}$$

- Where $SR^{\%}$ is the spinning reserve percentage.
- The zonal contingency constraint stated that:

$$P_1^{SR} + P_2^{SR} + P_3^{SR} + P_2^{XR} + P_3^{XR} = Z_1^{CR} \qquad \text{(CR Balance)}$$

- Combining these equations and eliminating $Z_1^{CR}$, we obtain the new tableau row:

$$(1 - SR^{\%})(P_1^{SR} + P_2^{SR} + P_3^{SR}) - SR^{\%}(P_2^{XR} + P_3^{XR}) \geq 0$$

# Spinning Percent Example

- Consider the 3-bus case with contingency reserves only (no regulating or operating reserve constraints)
- Since this case has only one area and one zone, which are the same, let us apply a 40% percent requirement to the Area Spinning Reserve.
- Let us also set up the following generator data:

| | Gen Records | | | | | |
|---|---|---|---|---|---|---|
| | Spn Avail. | Sup Avail | SPN Max | SUP Max | SPN Price | SUP Price |
| Gen1 | NO | NO | 120 | 10 | 6 | 5 |
| Gen2 | YES | YES | 30 | 48 | 4 | **3.2** |
| Gen3 | YES | YES | 30 | 36 | 4.5 | 3.7 |

# Spinning Percent Example

Solution w/o SPN% Enforced

Solution with SPN% Enforced

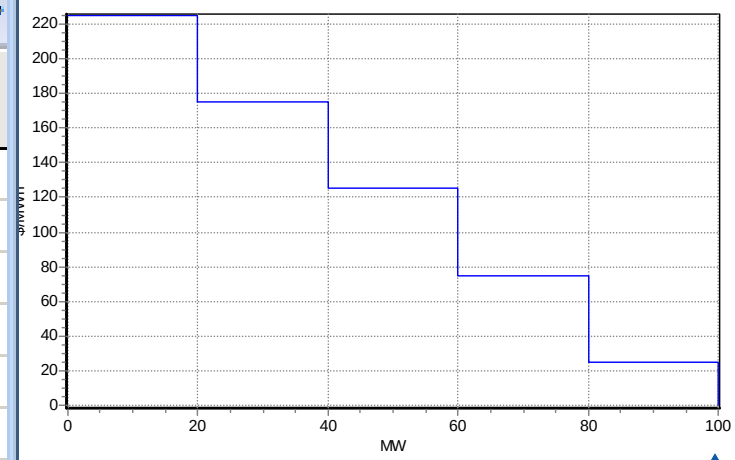
LP Solution Details

All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Ba

Records Set Columns

| | ID | Org. Value | Value |
|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 119.704 | 119.704 |
| 2 | Gen 2 #1 MW Control | 60.296 | 60.296 |
| 3 | Gen 2 #1 SPN MW Control | 16.000 | 30.000 |
| 4 | Gen 2 #1 SUP MW Control | 48.000 | 48.000 |
| 5 | Gen 3 #1 MW Control | 0.000 | 0.000 |
| 6 | Gen 3 #1 SPN MW Control | 0.000 | 10.000 |
| 7 | Gen 3 #1 SUP MW Control | 36.000 | 12.000 |
| 8 | Area Home CTG MW Control | 100.000 | 100.000 |
| 9 | Slack-Area Home | 0.000 | 0.000 |
| 10 | Slack-Area Home CTG | 0.000 | 0.000 |
| 11 | Slack-Line 1 TO 3 CKT 1 | 0.000 | 0.000 |
| 12 | Slack-Area Home SPN % | -24.000 | 0.000 |

Contingency Reserve Requirement Curve



# Spinning Percent Example

75% Solution

90% Solution

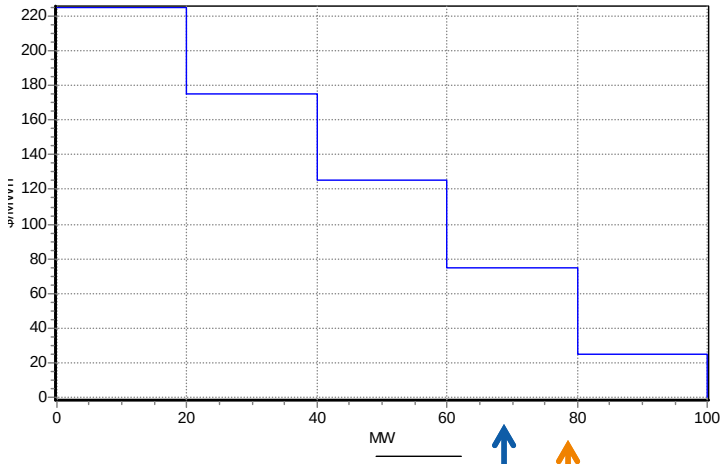
LP Solution Details

All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Ba

Records ▾ Set ▾ Columns

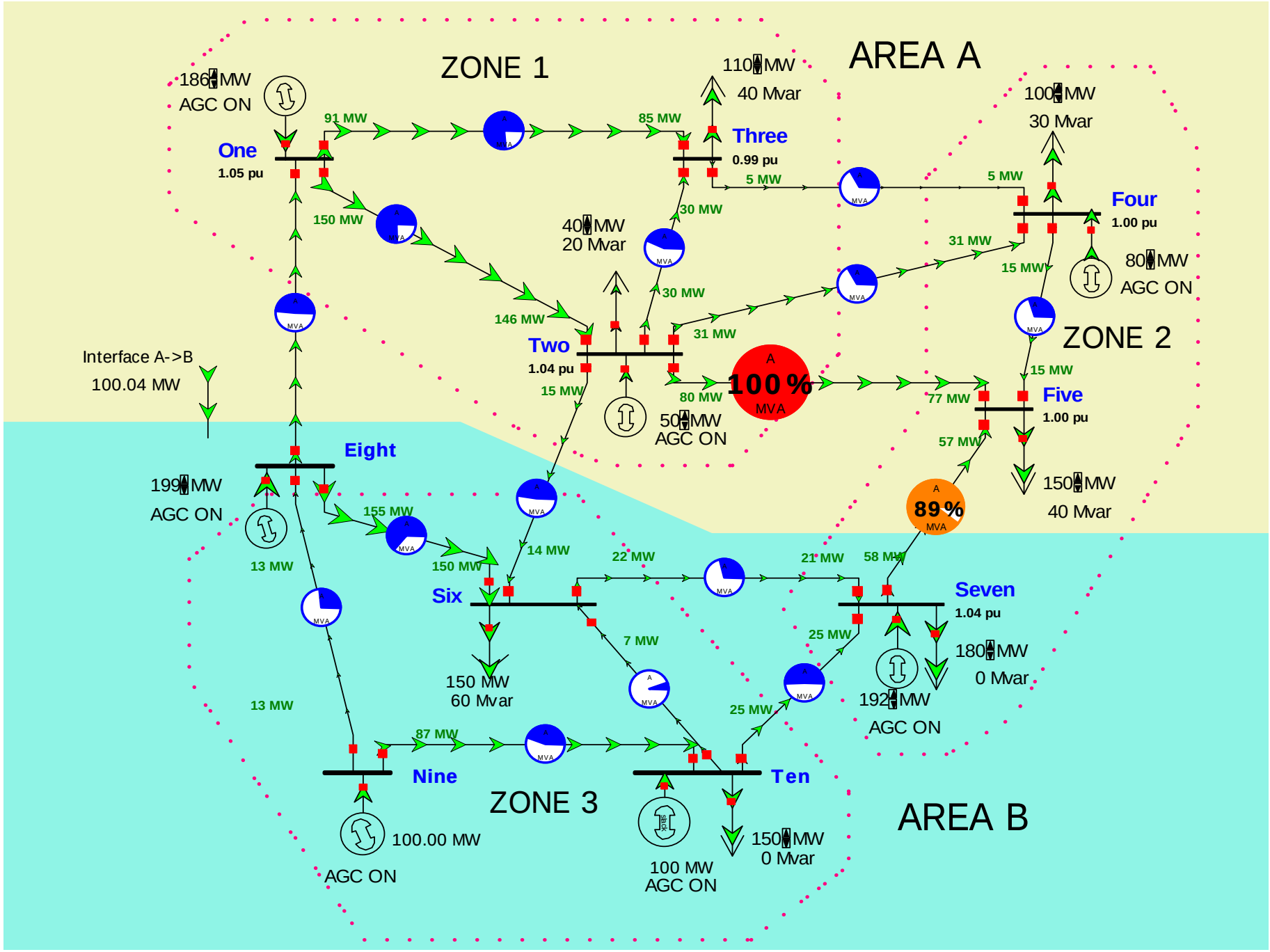
| | ID | Org. Value | Value |
|---|---|---|---|
| 1 | Gen 1 #1 MW Control | 119.704 | 119.704 |
| 2 | Gen 2 #1 MW Control | 60.296 | 60.296 |
| 3 | Gen 2 #1 SPN MW Control | 30.000 | 30.000 |
| 4 | Gen 2 #1 SUP MW Control | 20.000 | 6.667 |
| 5 | Gen 3 #1 MW Control | 0.000 | 0.000 |
| 6 | Gen 3 #1 SPN MW Control | 30.000 | 30.000 |
| 7 | Gen 3 #1 SUP MW Control | 0.000 | 0.000 |
| 8 | Area Home CTG MW Control | 80.000 | 66.667 |
| 9 | Slack-Area Home | 0.000 | 0.000 |
| 10 | Slack-Area Home CTG | 0.000 | 0.000 |
| 11 | Slack-Line 1 TO 3 CKT 1 | 0.000 | 0.000 |
| 12 | Slack-Area Home SPN % | -12.000 | 0.000 |

Contingency Reserve Requirement Curve



# Multiple Area/Zone Case

- Open B10Reserve.pwb
- Case has 2 control areas and 3 zones
- Solve LP OPF without reserves.
- Initial LP OPF without reserves presents a binding transmission line.



# Multiple Area/Zone Case

- The reserves constraints are enforced for each area AND zone, and for each reserve type whose Enforce Field is set to YES.
- Transmission line limits are observed
- Generator MW Max and Min limits are observed.
- In addition, area scheduled interchange is observed.
  - Currently, there is a 100MW export from Area B into Area A.

# Multiple Area/Zone Case

- Set up the following control parameters

Generators | Loads | Areas | Zones | Super Areas

| | Number of Bus | Name of Bus | ID | REG Avail. | SPN Avail. | SUP Avail | Min MW | Min Reg MW | Gen MW | REG MW Up | REG MW Down | SPN MW Up | SUP MW Up | Max Reg MW | Max MW | REG Max Up | REG Max Down | SPN Max | SUP Max | REG Price | SPN Price | SUP Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | One | 1 | YES | NO | NO | 50.00 | 0.00 | 186.06 | 0.00 | 0.00 | 0.00 | 0.00 | 250.00 | 250.00 | 50.00 | 50.00 | 102.50 | 29.00 | 10.00 | 15.00 | 10.50 |
| 2 | 2 | Two | 1 | YES | YES | NO | 50.00 | 0.00 | 50.00 | 0.00 | 0.00 | 0.00 | 0.00 | 300.00 | 300.00 | 60.00 | 50.00 | 112.50 | 34.00 | 12.00 | 13.00 | 9.50 |
| 3 | 4 | Four | 1 | NO | YES | YES | 50.00 | 0.00 | 80.00 | 0.00 | 0.00 | 0.00 | 0.00 | 200.00 | 200.00 | 70.00 | 50.00 | 122.50 | 39.00 | 14.00 | 11.00 | 8.50 |
| 4 | 7 | Seven | 1 | YES | NO | YES | 0.00 | 0.00 | 192.12 | 0.00 | 0.00 | 0.00 | 0.00 | 300.00 | 300.00 | 80.00 | 50.00 | 132.50 | 44.00 | 18.00 | 9.00 | 7.50 |
| 5 | 8 | Eight | 1 | YES | YES | NO | 150.00 | 0.00 | 198.97 | 0.00 | 0.00 | 0.00 | 0.00 | 300.00 | 300.00 | 90.00 | 50.00 | 142.50 | 49.00 | 24.00 | 7.00 | 6.50 |
| 6 | 9 | Nine | 1 | NO | YES | YES | 0.00 | 0.00 | 100.00 | 0.00 | 0.00 | 0.00 | 0.00 | 200.00 | 200.00 | 100.00 | 50.00 | 152.50 | 54.00 | 30.00 | 5.00 | 5.50 |
| 7 | 10 | Ten | 1 | NO | NO | YES | 0.00 | 0.00 | 100.02 | 0.00 | 0.00 | 0.00 | 0.00 | 1000.00 | 1000.00 | 110.00 | 0.00 | 202.50 | 59.00 | 40.00 | 3.00 | 4.50 |

| Number of Bus | Name of Bus | ID | REG Avail. | SPN Avail. | SUP Avail. |
|---|---|---|---|---|---|
| 1 | One | 1 | YES | NO | NO |
| 2 | Two | 1 | YES | YES | NO |
| 4 | Four | 1 | NO | YES | YES |
| 7 | Seven | 1 | YES | NO | YES |
| 8 | Eight | 1 | YES | YES | NO |
| 9 | Nine | 1 | NO | YES | YES |
| 10 | Ten | 1 | NO | NO | YES |

Reserve Control Availability

| REG Max Up | REG Max Down | SPN Max | SUP Max | REG Price | SPN Price | SUP Price |
|---|---|---|---|---|---|---|
| 50.00 | 50.00 | 102.50 | 29.00 | 10.00 | 15.00 | 10.50 |
| 60.00 | 50.00 | 112.50 | 34.00 | 12.00 | 13.00 | 9.50 |
| 70.00 | 50.00 | 122.50 | 39.00 | 14.00 | 11.00 | 8.50 |
| 80.00 | 50.00 | 132.50 | 44.00 | 18.00 | 9.00 | 7.50 |
| 90.00 | 50.00 | 142.50 | 49.00 | 24.00 | 7.00 | 6.50 |
| 100.00 | 50.00 | 152.50 | 54.00 | 30.00 | 5.00 | 5.50 |
| 110.00 | 0.00 | 202.50 | 59.00 | 40.00 | 3.00 | 4.50 |

Reserve Control Limits and Prices

# Multiple Area/Zone Case

- Set up the following reserve constraint requirements:

| | Enforce | | | Requirement | | |
|---|---|---|---|---|---|---|
| | OPR | REG | CTG | OPR | REG | CTG |
| Area A | YES | YES | | 150 @ 400 | 80 @ 300 | |
| Area B | YES | YES | | 90 @ 250 | 60 @ 150 | |
| Zone 1 | | | YES | | | 65 @ 300 |
| Zone 2 | | | YES | | | 45 @ 140 |
| Zone 3 | | | YES | | | 35 @ 120 |

- Solve the LP-OPF

# Generator Control Result

OPF Reserve Requirements Results | OPF Generators

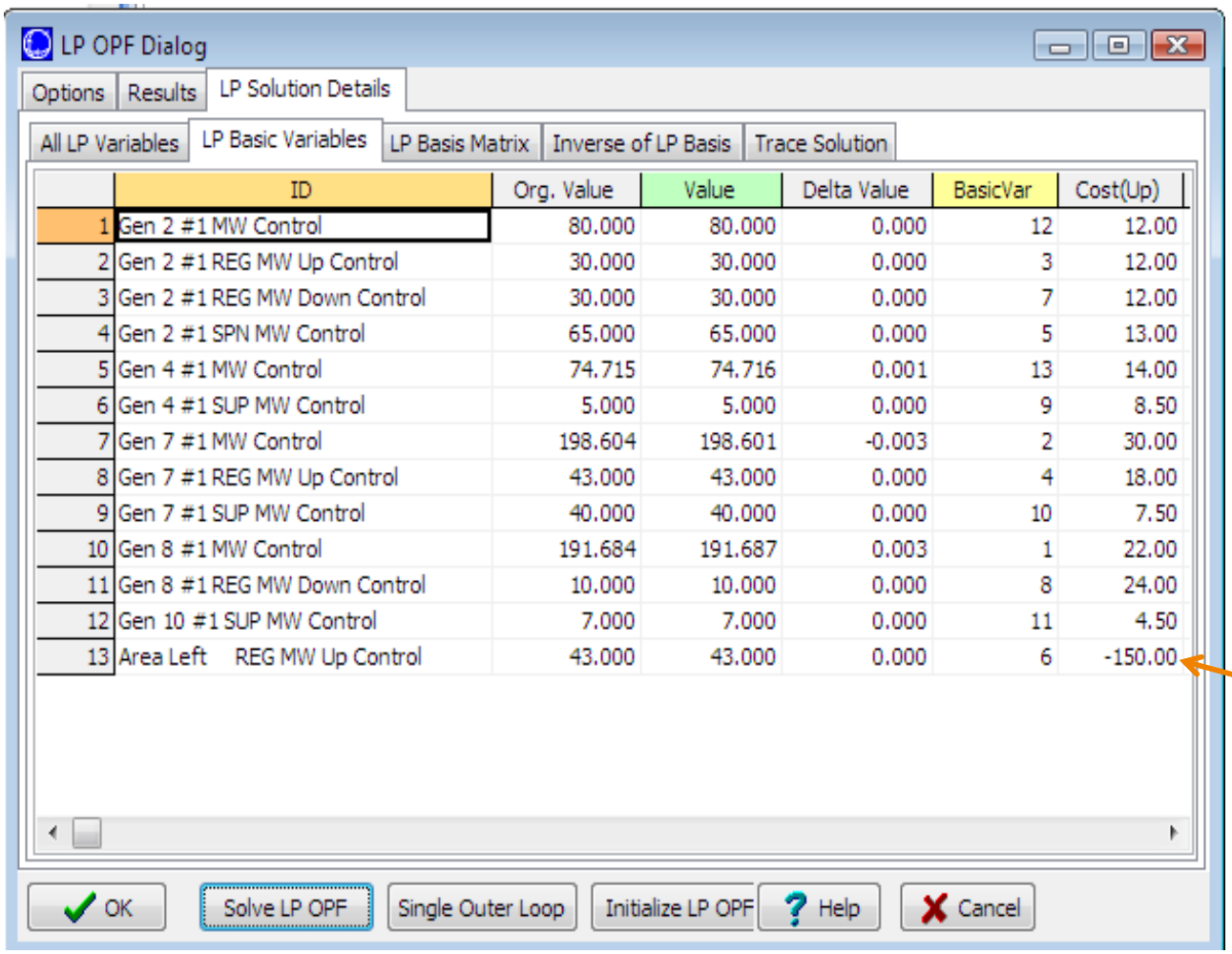
Records Geo Set Columns Options

Generators | Loads | Areas | Zones | Super Areas

| | Number of Bus | Name of Bus | ID | REG Avail. | SPN Avail. | SUP Avail. | Min MW | Min Reg MW | Gen MW | REG MW Up | REG MW Down | SPN MW Up | SUP MW Up | Max Reg MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | One | 1 | YES | NO | NO | 50.00 | 0.00 | 160.00 | 50.00 | 50.00 | 0.00 | 0.00 | 250.00 |
| 2 | 2 | Two | 1 | YES | YES | NO | 50.00 | 0.00 | 80.00 | 30.00 | 30.00 | 65.00 | 0.00 | 300.00 |
| 3 | 4 | Four | 1 | NO | YES | YES | 50.00 | 0.00 | 74.72 | 0.00 | 0.00 | 0.00 | 5.00 | 200.00 |
| 4 | 7 | Seven | 1 | YES | NO | YES | 0.00 | 0.00 | 198.60 | 43.00 | 50.00 | 0.00 | 40.00 | 300.00 |
| 5 | 8 | Eight | 1 | YES | YES | NO | 150.00 | 0.00 | 191.68 | 0.00 | 10.00 | 0.00 | 0.00 | 300.00 |
| 6 | 9 | Nine | 1 | NO | YES | YES | 0.00 | 0.00 | 100.00 | 0.00 | 0.00 | 0.00 | 0.00 | 200.00 |
| 7 | 10 | Ten | 1 | NO | NO | YES | 0.00 | 0.00 | 99.87 | 0.00 | 0.00 | 0.00 | 7.00 | 1000.00 |

Some of the generator reserve MW values are maxed out in this example. Other are within limits.

# Basic Variables Result




| | ID | Org. Value | Value | Delta Value | BasicVar | Cost(Up) |
|---|---|---|---|---|---|---|
| 1 | Gen 2 #1 MW Control | 80.000 | 80.000 | 0.000 | 12 | 12.00 |
| 2 | Gen 2 #1 REG MW Up Control | 30.000 | 30.000 | 0.000 | 3 | 12.00 |
| 3 | Gen 2 #1 REG MW Down Control | 30.000 | 30.000 | 0.000 | 7 | 12.00 |
| 4 | Gen 2 #1 SPN MW Control | 65.000 | 65.000 | 0.000 | 5 | 13.00 |
| 5 | Gen 4 #1 MW Control | 74.715 | 74.716 | 0.001 | 13 | 14.00 |
| 6 | Gen 4 #1 SUP MW Control | 5.000 | 5.000 | 0.000 | 9 | 8.50 |
| 7 | Gen 7 #1 MW Control | 198.604 | 198.601 | -0.003 | 2 | 30.00 |
| 8 | Gen 7 #1 REG MW Up Control | 43.000 | 43.000 | 0.000 | 4 | 18.00 |
| 9 | Gen 7 #1 SUP MW Control | 40.000 | 40.000 | 0.000 | 10 | 7.50 |
| 10 | Gen 8 #1 MW Control | 191.684 | 191.687 | 0.003 | 1 | 22.00 |
| 11 | Gen 8 #1 REG MW Down Control | 10.000 | 10.000 | 0.000 | 8 | 24.00 |
| 12 | Gen 10 #1 SUP MW Control | 7.000 | 7.000 | 0.000 | 11 | 4.50 |
| 13 | Area Left REG MW Up Control | 43.000 | 43.000 | 0.000 | 6 | -150.00 |

Negative of marginal benefit for binding constraints. These constraints will cause scarcity pricing.

# Area Results

Reserve Requirement Curves

Operating | Regulating | Contingency | Results

**AREA A**

| | REG + | REG-- | SPN | SUP | CTG | OPR |
|---|---|---|---|---|---|---|
| Enforce | YES | YES | NO | NO | NO | YES |
| Cleared MW | 80.00 | 80.00 | 65.00 | 5.00 | 70.00 | 150.00 |
| Max Reserve MW | 110.00 | 100.00 | 235.00 | 39.00 | 274.00 | 384.00 |
| Hourly Cost $/hr | 860.00 | 860.00 | 845.00 | 42.50 | 887.50 | 1747.50 |
| Price $/MWh | 143.00 | 12.00 | | | -201.00 | -131.00 |
| Hourly Benefit $/hr | 24000.00 | 24000.00 | | | 0.00 | 60000.00 |

Area A enforces Operation and Regulation Reserve. Prices are obtained for each one of these constraints. There is scarcity pricing so the price is given by the demand curve.

Operating | Regulating | Contingency | Results

**AREA B**

| | REG + | REG-- | SPN | SUP | CTG | OPR |
|---|---|---|---|---|---|---|
| Enforce | YES | YES | NO | NO | NO | YES |
| Cleared MW | 43.00 | 60.00 | 0.00 | 47.00 | 47.00 | 90.00 |
| Max Reserve MW | 170.00 | 100.00 | 295.00 | 157.00 | 452.00 | 622.00 |
| Hourly Cost $/hr | 774.00 | 1140.00 | 0.00 | 331.50 | 331.50 | 1105.50 |
| Price $/MWh | 150.00 | 24.00 | | | 0.00 | -132.00 |
| Hourly Benefit $/hr | 6450.00 | 9000.00 | | | 0.00 | 22500.00 |

Area B enforces Operation and Regulation Reserve. There is scarcity pricing.

# Zone Results

Reserve Requirement Curves

Operating | Regulating | Contingency | Results

**ZONE 1**

| | REG + | REG-- | SPN | SUP | CTG | OPR |
|---|---|---|---|---|---|---|
| Enforce | NO | NO | NO | NO | YES | NO |
| Cleared MW | 80.00 | 80.00 | 65.00 | 0.00 | 65.00 | 145.00 |
| Max Reserve MW | 110.00 | 100.00 | 112.50 | 0.00 | 112.50 | 222.50 |
| Hourly Cost $/hr | 860.00 | 860.00 | 845.00 | 0.00 | 845.00 | 1705.00 |
| Price $/MWh | 0.00 | 0.00 | | | 144.00 | 0.00 |
| Hourly Benefit $/hr | 0.00 | 0.00 | | | 19500.00 | 0.00 |

Reserve Requirement Curves

Operating | Regulating | Contingency | Results

**ZONE 3**

| | REG + | REG-- | SPN | SUP | CTG | OPR |
|---|---|---|---|---|---|---|
| Enforce | NO | NO | NO | NO | YES | NO |
| Cleared MW | 0.00 | 10.00 | 0.00 | 7.00 | 7.00 | 7.00 |
| Max Reserve MW | 90.00 | 50.00 | 295.00 | 113.00 | 408.00 | 498.00 |
| Hourly Cost $/hr | 0.00 | 240.00 | 0.00 | 31.50 | 31.50 | 31.50 |
| Price $/MWh | 0.00 | 0.00 | | | 136.50 | 0.00 |
| Hourly Benefit $/hr | 0.00 | 0.00 | | | 840.00 | 0.00 |

Reserve Requirement Curves

Operating | Regulating | Contingency | Results

**ZONE 2**

| | REG + | REG-- | SPN | SUP | CTG | OPR |
|---|---|---|---|---|---|---|
| Enforce | NO | NO | NO | NO | YES | NO |
| Cleared MW | 43.00 | 50.00 | 0.00 | 45.00 | 45.00 | 88.00 |
| Max Reserve MW | 80.00 | 50.00 | 122.50 | 83.00 | 205.50 | 285.50 |
| Hourly Cost $/hr | 774.00 | 900.00 | 0.00 | 342.50 | 342.50 | 1116.50 |
| Price $/MWh | 300.00 | 300.00 | | | 139.50 | 500.00 |
| Hourly Benefit $/hr | 0.00 | 0.00 | | | 6300.00 | 0.00 |

# Resulting Prices

LP OPF Dialog

Options | Results | LP Solution Details

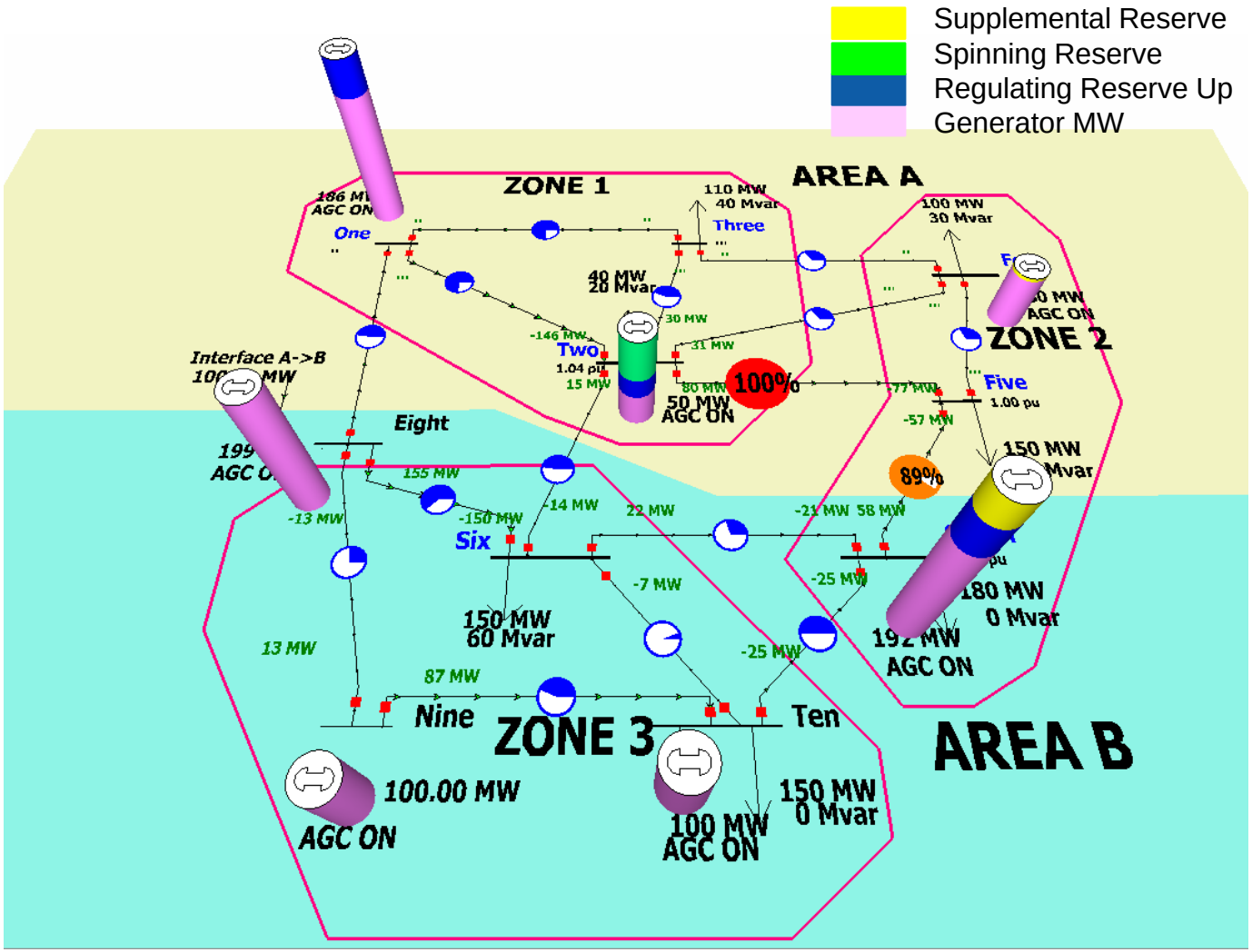
Solution Summary | Bus MW Marginal Price Details | Bus Mvar Marginal Price Details | Bus Marginal Controls

Records Geo Set Columns f(x)

| | Number | Name | Area Name | MW Marg. Cost | Energy $/MWh | Conges $/MWh | Losses $/MWh | Area 1 MW Constraint | Area 2 MW Constrain | Area 1 Area OPR ResMW Constraint | Area 2 Area OPR ResMW Constraint | Area 1 Area REG ResMWUp Constraint | Area 2 Area REG ResMWUp Constraint |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | One | A | 11.14 | 15.12 | -3.28 | -0.69 | 14.43 | 0.00 | -131.00 | 0.00 | 143.00 | 0.00 |
| 2 | 2 | Two | A | 10.54 | 15.12 | -4.55 | -0.02 | 15.10 | 0.00 | -131.00 | 0.00 | 143.00 | 0.00 |
| 3 | 3 | Three | A | 13.49 | 15.12 | -2.33 | 0.70 | 15.82 | 0.00 | -131.00 | 0.00 | 143.00 | 0.00 |
| 4 | 4 | Four | A | 14.00 | 15.12 | -1.77 | 0.65 | 15.77 | 0.00 | -131.00 | 0.00 | 143.00 | 0.00 |
| 5 | 5 | Five | A | 22.86 | 15.12 | 6.96 | 0.79 | 15.90 | 0.00 | -131.00 | 0.00 | 143.00 | 0.00 |
| 6 | 6 | Six | B | 23.08 | 25.20 | -2.29 | 0.17 | 0.00 | 25.37 | 0.00 | -132.00 | 0.00 | 150.00 |
| 7 | 7 | Seven | B | 30.00 | 25.20 | 4.13 | 0.66 | 0.00 | 25.87 | 0.00 | -132.00 | 0.00 | 150.00 |
| 8 | 8 | Eight | B | 22.00 | 25.20 | -2.16 | -1.05 | 0.00 | 24.16 | 0.00 | -132.00 | 0.00 | 150.00 |
| 9 | 9 | Nine | B | 22.12 | 25.20 | -1.50 | -1.57 | 0.00 | 23.63 | 0.00 | -132.00 | 0.00 | 150.00 |
| 10 | 10 | Ten | B | 25.20 | 25.20 | 0.00 | 0.00 | 0.00 | 25.20 | 0.00 | -132.00 | 0.00 | 150.00 |

Marginal effect of each constraint on the reserve market clearing prices. High values indicate scarcity pricing.

# Reserves 3-D Visualization



# Effect of Removing Constraints

- In the previous example, we noticed that although generators 9 and 10 can provide contingency reserve for Zone 3, this would also add operating reserve for Area B, possibly decreasing the "value" of the reserve.
- In order to illustrate this effect, let us disable the enforcement of operating reserves in Area B (keeping the enforcement of regulating reserves for this area).

# Effect of Removing Constraints

LP OPF Dialog

Options | Results | LP Solution Details

Solution Summary | Bus MW Marginal Price Details | Bus Mvar Marginal Price Details | Bus Marginal Controls

Records ▾ Geo ▾ Set ▾ Columns ▾

| | Number | Name | Area Name | MW Marg. Cost | Energy $/MWh | Congestion $/MWh | Losses $/MWh | Area 1 MW Constr | Area 2 MW Constraint | Area 1 Area OPR ResMW Constraint | Area 1 Area REG ResMWUp Constraint | Area 2 Area REG ResMWUp Constraint | Ar Ar Re Co |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | One | A | 11.14 | 15.12 | -3.28 | -0.69 | 14.43 | 0.00 | 1.00 | 11.00 | 0.00 | |
| 2 | 2 | Two | A | 10.54 | 15.12 | -4.55 | -0.02 | 15.10 | 0.00 | 1.00 | 11.00 | 0.00 | |
| 3 | 3 | Three | A | 13.49 | 15.12 | -2.33 | 0.70 | 15.82 | 0.00 | 1.00 | 11.00 | 0.00 | |
| 4 | 4 | Four | A | 14.00 | 15.12 | -1.77 | 0.65 | 15.77 | 0.00 | 1.00 | 11.00 | 0.00 | |
| 5 | 5 | Five | A | 22.86 | 15.12 | 6.96 | 0.79 | 15.90 | 0.00 | 1.00 | 11.00 | 0.00 | |
| 6 | 6 | Six | B | 23.08 | 25.20 | -2.29 | 0.17 | 0.00 | 25.37 | 0.00 | 0.00 | 18.00 | |
| 7 | 7 | Seven | B | 30.00 | 25.20 | 4.13 | 0.66 | 0.00 | 25.87 | 0.00 | 0.00 | 18.00 | |
| 8 | 8 | Eight | B | 22.00 | 25.20 | -2.16 | -1.05 | 0.00 | 24.16 | 0.00 | 0.00 | 18.00 | |
| 9 | 9 | Nine | B | 22.12 | 25.20 | -1.50 | -1.57 | 0.00 | 23.63 | 0.00 | 0.00 | 18.00 | |
| 1 | | | | | | | | 0 | 25.20 | 0.00 | 0.00 | 18.00 | |

Now prices reflect the absence of scarcity pricing.

# Effect of Available Reserves

- Now assume available reserves are equal to half of the previously available reserves for all generators and all types of reserve controls.
- Solve the LP-OPF

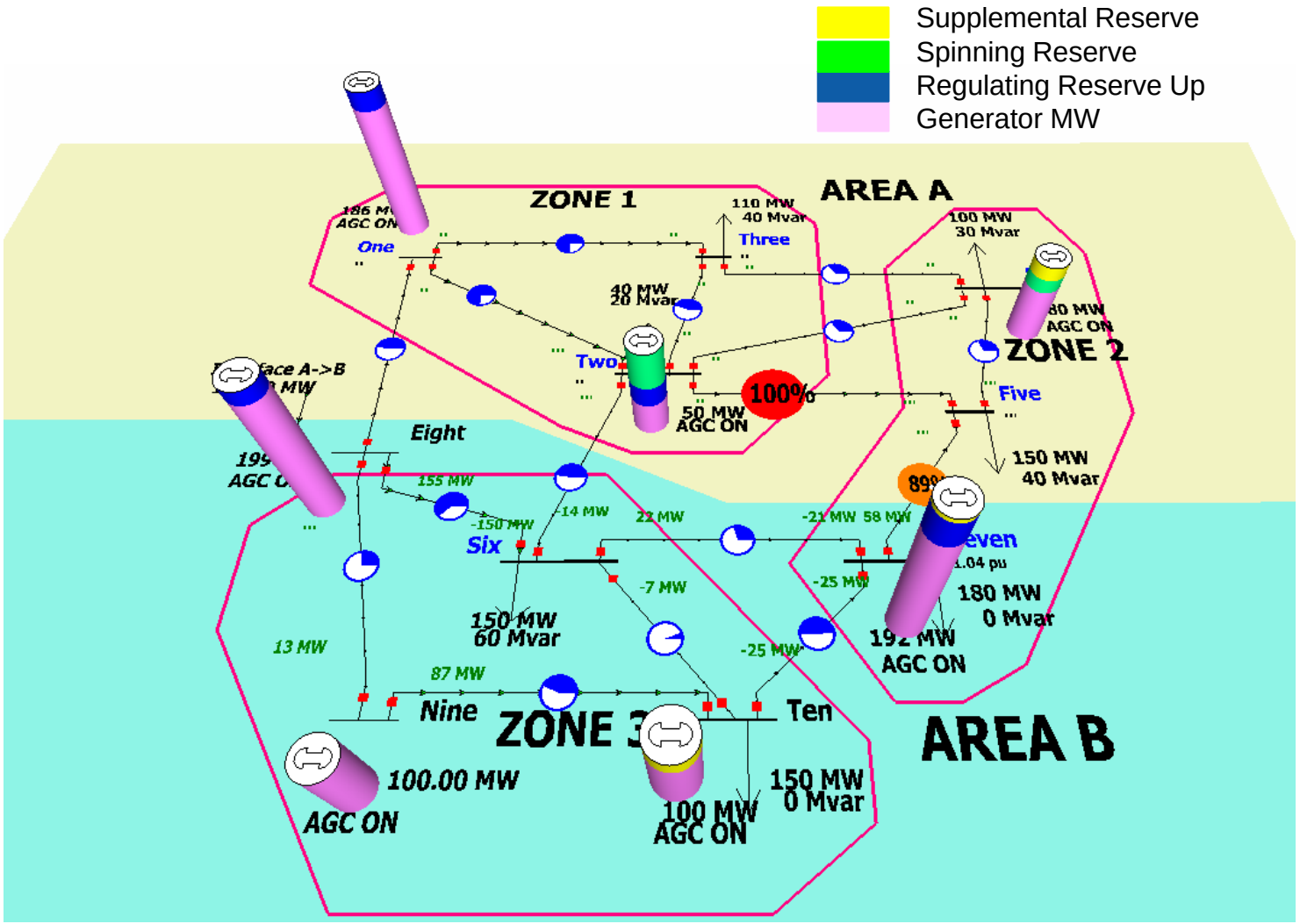
Options | Results | LP Solution Details

All LP Variables | LP Basic Variables | LP Basis Matrix | Inverse of LP Basis | Trace Solution

| | ID | Org. Value | Value | Delta Value | BasicVar | Cost(Up) |
|---|---|---|---|---|---|---|
| 1 | Gen 2 #1 MW Control | 80.000 | 75.000 | -5.000 | 11 | 12.00 |
| 2 | Gen 4 #1 MW Control | 74.720 | 79.622 | 4.902 | 12 | 14.00 |
| 3 | Gen 4 #1 SPN MW Control | 0.000 | 19.250 | 19.250 | 3 | 11.00 |
| 4 | Gen 7 #1 MW Control | 198.600 | 196.405 | -2.195 | 1 | 30.00 |
| 5 | Gen 7 #1 SUP MW Control | 40.000 | 6.250 | -33.750 | 9 | 7.50 |
| 6 | Gen 8 #1 MW Control | 191.690 | 194.033 | 2.343 | 2 | 22.00 |
| 7 | Gen 8 #1 REG MW Up Control | 0.000 | 20.000 | 20.000 | 5 | 24.00 |
| 8 | Gen 9 #1 SPN MW Control | 0.000 | 5.500 | 5.500 | 10 | 5.00 |
| 9 | Area Top REG MW Up Control | 80.000 | 55.000 | -25.000 | 4 | -300.00 |
| 10 | Area Top REG MW Down Cont | 80.000 | 50.000 | -30.000 | 6 | -300.00 |
| 11 | Area Left REG MW Down Contr | 60.000 | 50.000 | -10.000 | 7 | -150.00 |
| 12 | Zone 1 CTG MW Control | 65.000 | 56.250 | -8.750 | 8 | -300.00 |

Several reserve constraints now appear as binding, and prices will reflect scarcity.

# Effect of Available Reserves



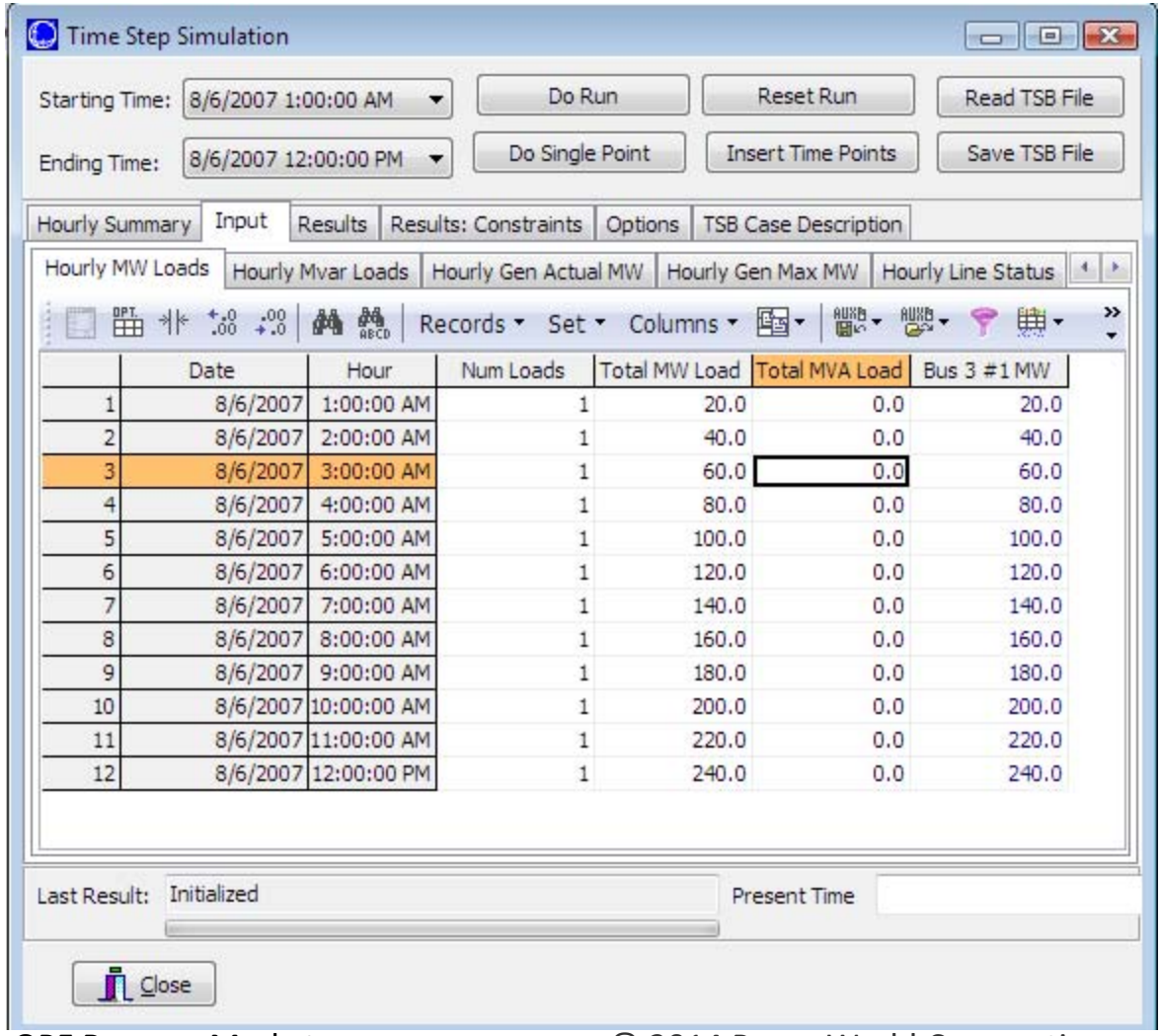
# Hour-by-hour Simulations

- Often, we need to analyze the reserve dispatch over a number of hours, instead of for a single hour.
- Simulator can perform power flow and OPF simulations using a Time Step Simulation (TSS) Tool.
- The TSS is described in more detail in Section "M7" of the training manual.
  - The TSS supports sequential simulation of reserve markets
  - We introduce the TSS without reserves

# Hour-by-hour Simulations

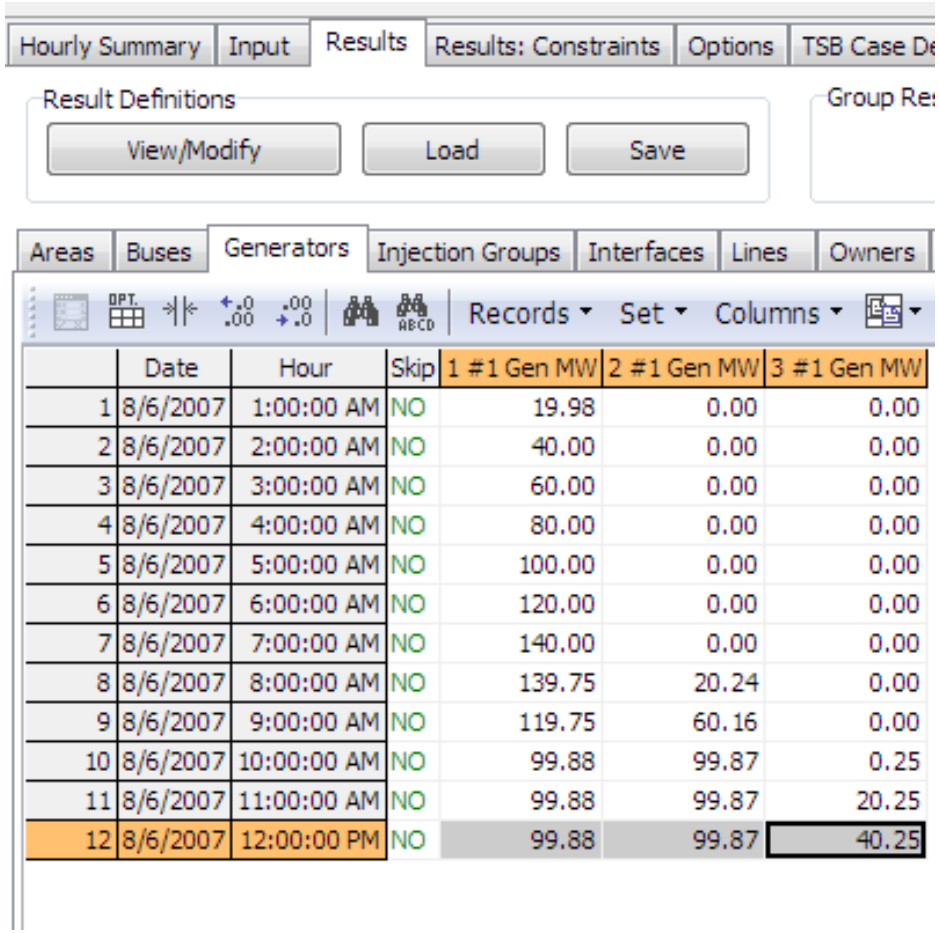
- Consider the 3-bus case without reserves.
- Recall the congestion example.
- Set the time step simulation so the load at bus 3 increases from 20 to 240MW in steps of 20 MW each hour. This represents a 12-hour study.
- Simulation considers congestion, thus generators will increase their output economically while they do not introduce congestion.

# Hour-by-hour Input Data

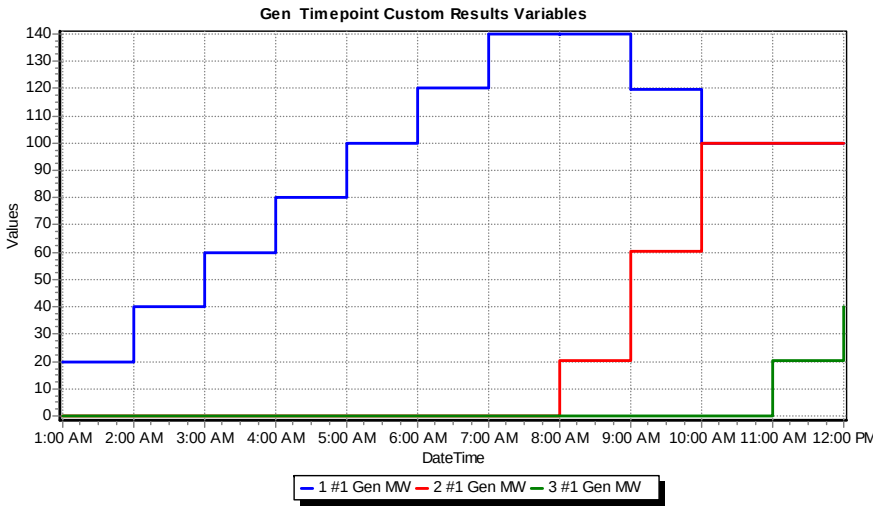



| | Date | Hour | Num Loads | Total MW Load | Total MVA Load | Bus 3 #1 MW |
|---|---|---|---|---|---|---|
| 1 | 8/6/2007 | 1:00:00 AM | 1 | 20.0 | 0.0 | 20.0 |
| 2 | 8/6/2007 | 2:00:00 AM | 1 | 40.0 | 0.0 | 40.0 |
| 3 | 8/6/2007 | 3:00:00 AM | 1 | 60.0 | 0.0 | 60.0 |
| 4 | 8/6/2007 | 4:00:00 AM | 1 | 80.0 | 0.0 | 80.0 |
| 5 | 8/6/2007 | 5:00:00 AM | 1 | 100.0 | 0.0 | 100.0 |
| 6 | 8/6/2007 | 6:00:00 AM | 1 | 120.0 | 0.0 | 120.0 |
| 7 | 8/6/2007 | 7:00:00 AM | 1 | 140.0 | 0.0 | 140.0 |
| 8 | 8/6/2007 | 8:00:00 AM | 1 | 160.0 | 0.0 | 160.0 |
| 9 | 8/6/2007 | 9:00:00 AM | 1 | 180.0 | 0.0 | 180.0 |
| 10 | 8/6/2007 | 10:00:00 AM | 1 | 200.0 | 0.0 | 200.0 |
| 11 | 8/6/2007 | 11:00:00 AM | 1 | 220.0 | 0.0 | 220.0 |
| 12 | 8/6/2007 | 12:00:00 PM | 1 | 240.0 | 0.0 | 240.0 |

# Hour-by-hour Generator Results

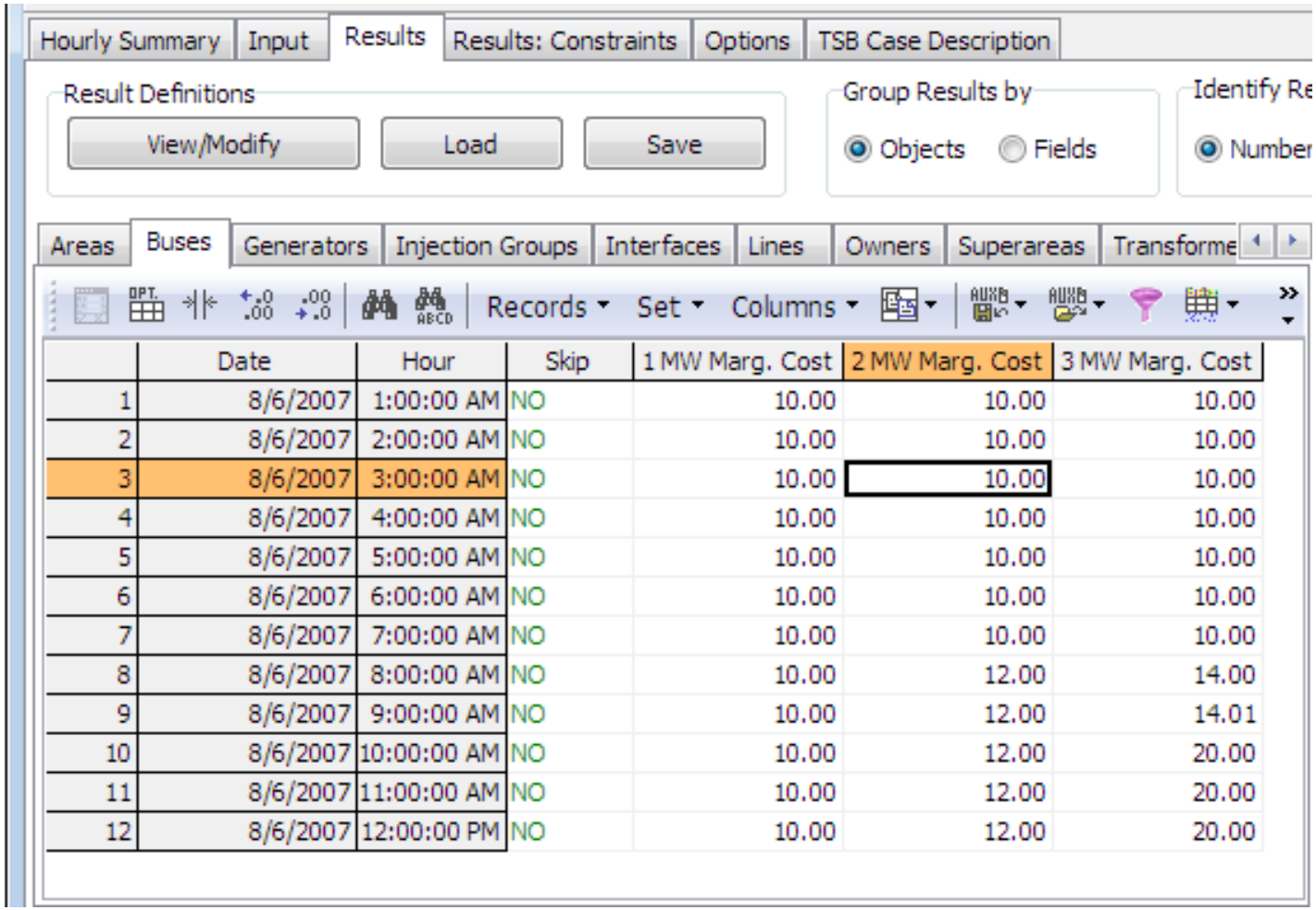



| | Date | Hour | Skip | 1 #1 Gen MW | 2 #1 Gen MW | 3 #1 Gen MW |
|---|---|---|---|---|---|---|
| 1 | 8/6/2007 | 1:00:00 AM | NO | 19.98 | 0.00 | 0.00 |
| 2 | 8/6/2007 | 2:00:00 AM | NO | 40.00 | 0.00 | 0.00 |
| 3 | 8/6/2007 | 3:00:00 AM | NO | 60.00 | 0.00 | 0.00 |
| 4 | 8/6/2007 | 4:00:00 AM | NO | 80.00 | 0.00 | 0.00 |
| 5 | 8/6/2007 | 5:00:00 AM | NO | 100.00 | 0.00 | 0.00 |
| 6 | 8/6/2007 | 6:00:00 AM | NO | 120.00 | 0.00 | 0.00 |
| 7 | 8/6/2007 | 7:00:00 AM | NO | 140.00 | 0.00 | 0.00 |
| 8 | 8/6/2007 | 8:00:00 AM | NO | 139.75 | 20.24 | 0.00 |
| 9 | 8/6/2007 | 9:00:00 AM | NO | 119.75 | 60.16 | 0.00 |
| 10 | 8/6/2007 | 10:00:00 AM | NO | 99.88 | 99.87 | 0.25 |
| 11 | 8/6/2007 | 11:00:00 AM | NO | 99.88 | 99.87 | 20.25 |
| 12 | 8/6/2007 | 12:00:00 PM | NO | 99.88 | 99.87 | 40.25 |




Gen1 can increase its output up to 150 MW, when line 1 to 3 becomes 100% loaded. Then Gen2 must increase its output, but Gen1 must decrease simultaneously so line 1 to 3 does not become overloaded. When Gen1 and Gen2 are both generating 100MW, both lines 1 to 2 and 2 to 3 are loaded at 100%. Then Gen3 must generate to serve the load.

# Hour-by-hour Bus Marginal Prices



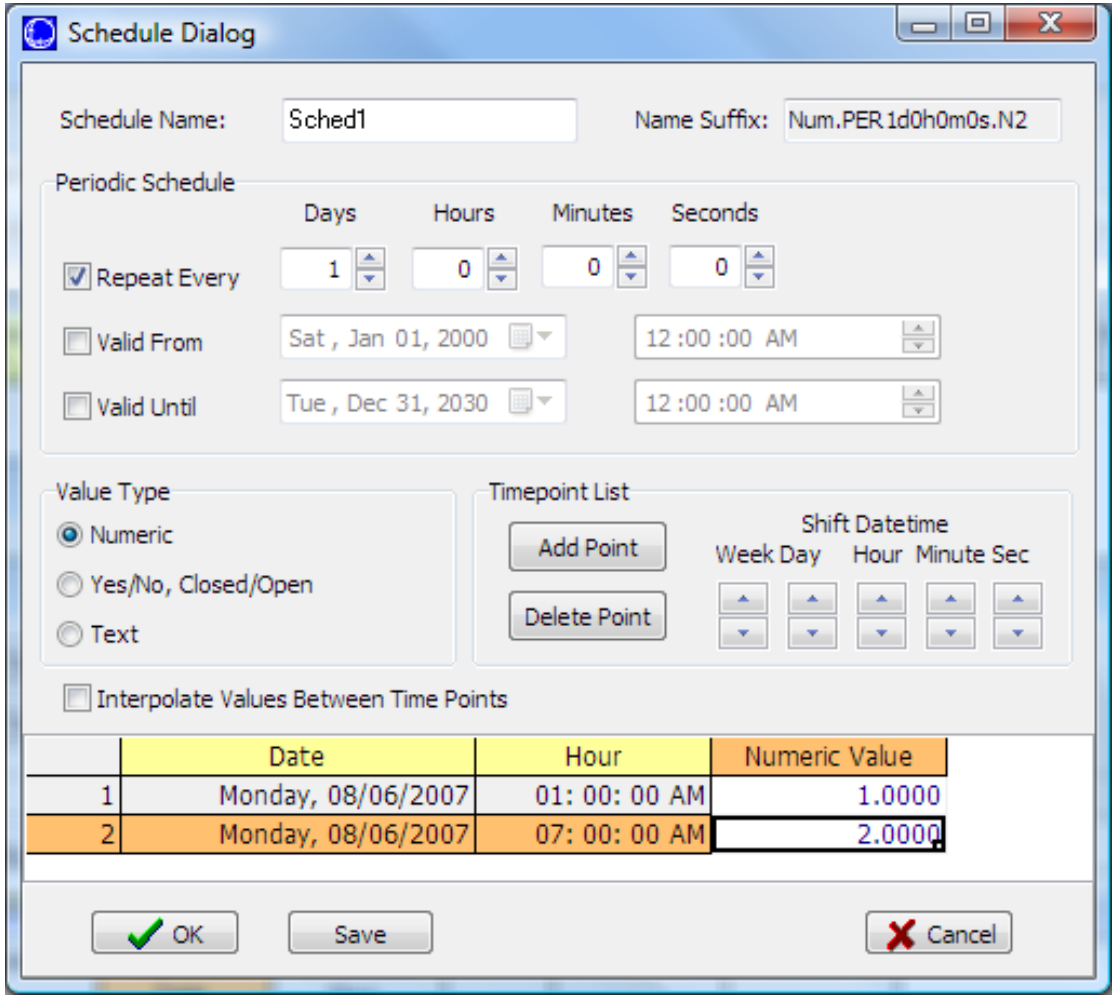

| | Date | Hour | Skip | 1 MW Marg. Cost | 2 MW Marg. Cost | 3 MW Marg. Cost |
|---|---|---|---|---|---|---|
| 1 | 8/6/2007 | 1:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 2 | 8/6/2007 | 2:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 3 | 8/6/2007 | 3:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 4 | 8/6/2007 | 4:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 5 | 8/6/2007 | 5:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 6 | 8/6/2007 | 6:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 7 | 8/6/2007 | 7:00:00 AM | NO | 10.00 | 10.00 | 10.00 |
| 8 | 8/6/2007 | 8:00:00 AM | NO | 10.00 | 12.00 | 14.00 |
| 9 | 8/6/2007 | 9:00:00 AM | NO | 10.00 | 12.00 | 14.01 |
| 10 | 8/6/2007 | 10:00:00 AM | NO | 10.00 | 12.00 | 20.00 |
| 11 | 8/6/2007 | 11:00:00 AM | NO | 10.00 | 12.00 | 20.00 |
| 12 | 8/6/2007 | 12:00:00 PM | NO | 10.00 | 12.00 | 20.00 |

# TSS Reserve Simulations

- Data that can be modified using the **Input** page
  - Individual Load MW and Mvar
  - Individual Generator MW and Mvar
  - Area and Zone Total Active and Reactive Load
- However, we are interested in modifying generator reserve-related input data such as reserve bids.
- ***Schedules*** can be used for this purpose.
- Let us assume that generators bid spinning reserves at double the price during day-hours than during night-hours. Let us set up the following schedule.

# TSS Reserve Simulations

Schedule will repeat every day. At 6 pm it will assume a value that will be doubled at 6am.



# TSS Reserve Simulations

- Then we subscribe the spinning reserve bid price variables to the schedule and scale the bids as follows:

Hourly Summary | Input | Results | Results: Constraints | Options | TSB Case Description

Hourly MW Loads | Hourly Mvar Loads | Hourly Gen Actual MW | Hourly Gen Max MW | Hourly Line Status | Hourly Area Loads | Hourly Zone Loa

Records ▾ Set ▾ Columns ▾ Options ▾

| | Object | Object ID1 | Object ID2 | Object ID3 | Object Field | Schedule Name | Suffix | Active | Relative | Multiplier | Value Shift |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Generator | 1 | 0 | 1 | OPF Input\Reserve Spinning Price | Sched1 | Num.PER0d0h0m0s.N2 | YES | YES | 10.0000 | 0.0000 |
| 2 | Generator | 2 | 0 | 1 | OPF Input\Reserve Spinning Price | Sched1 | Num.PER0d0h0m0s.N2 | YES | YES | 15.0000 | 0.0000 |
| 3 | Generator | 3 | 0 | 1 | OPF Input\Reserve Spinning Price | Sched1 | Num.PER0d0h0m0s.N2 | YES | YES | 18.0000 | 0.0000 |

SR price of Gen 1 will be 10 $/MWh during the night and 20 $/MWh during the day, respectively. Gen 2 will be 15 and 30 $/MWh, etc

# TSS Reserve Simulations

- Enforce Area Operation, Regulation and Contingency Reserve Requirements
- Set recourse available as for the complete 3-bus case simulation.
- In OPF Dialog check the options to:
  - Include Reserve Requirements in OPF
  - Use a single control for up and down regulation
- Run the TSS Simulation

# TSS Reserve Simulations

- Generator Results are as follows:

Areas | Buses | Generators | Injection Groups | Interfaces | Lines | Owners | Superareas | Transformers | Zones

Records ▾ Set ▾ Columns ▾ Options ▾

| | Date | Hour | Skip | 1 #1 SPN Price | 2 #1 SPN Price | 3 #1 SPN Price | 1 #1 Gen MW | 2 #1 Gen MW | 3 #1 Gen MW | 1 #1 REG MW Up | 2 #1 REG MW Up | 3 #1 REG MW Up | 1 #1 SPN MW Up | 2 #1 SPN MW Up | 3 #1 SPN MW Up | 1 #1 SUP MW Up | 2 #1 SUP MW Up | 3 #1 SUP MW Up |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 8/6/2007 | 1:00:00 AM | NO | 10.0 | 15.0 | 18.0 | 20.0 | 0.0 | 0.0 | 5.0 | 75.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 2 | 8/6/2007 | 2:00:00 AM | NO | 10.0 | 15.0 | 18.0 | 40.0 | 0.0 | 0.0 | 40.0 | 0.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 3 | 8/6/2007 | 3:00:00 AM | NO | 10.0 | 15.0 | 18.0 | 55.0 | 5.0 | 0.0 | 55.0 | 5.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 4 | 8/6/2007 | 4:00:00 AM | NO | 10.0 | 15.0 | 18.0 | 55.0 | 25.0 | 0.0 | 55.0 | 25.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 5 | 8/6/2007 | 5:00:00 AM | NO | 10.0 | 15.0 | 18.0 | 75.0 | 25.0 | 0.0 | 55.0 | 25.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 6 | 8/6/2007 | 6:00:00 AM | NO | 10.0 | 15.0 | 18.0 | 95.0 | 25.0 | 0.0 | 55.0 | 25.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 7 | 8/6/2007 | 7:00:00 AM | NO | 20.0 | 30.0 | 36.0 | 115.0 | 25.0 | 0.0 | 55.0 | 25.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 8 | 8/6/2007 | 8:00:00 AM | NO | 20.0 | 30.0 | 36.0 | 135.0 | 25.0 | 0.0 | 55.0 | 25.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 9 | 8/6/2007 | 9:00:00 AM | NO | 20.0 | 30.0 | 36.0 | 119.7 | 60.2 | 0.0 | 19.8 | 60.2 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 10 | 8/6/2007 | 10:00:00 AM | NO | 20.0 | 30.0 | 36.0 | 99.9 | 99.9 | 0.3 | 5.0 | 75.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 11 | 8/6/2007 | 11:00:00 AM | NO | 20.0 | 30.0 | 36.0 | 99.9 | 99.9 | 20.3 | 5.0 | 75.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |
| 12 | 8/6/2007 | 12:00:00 PM | NO | 20.0 | 30.0 | 36.0 | 99.9 | 99.9 | 40.3 | 5.0 | 75.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 48.0 | 36.0 |

Verify change in Reserve Bid Prices

Generator hourly cleared energy output

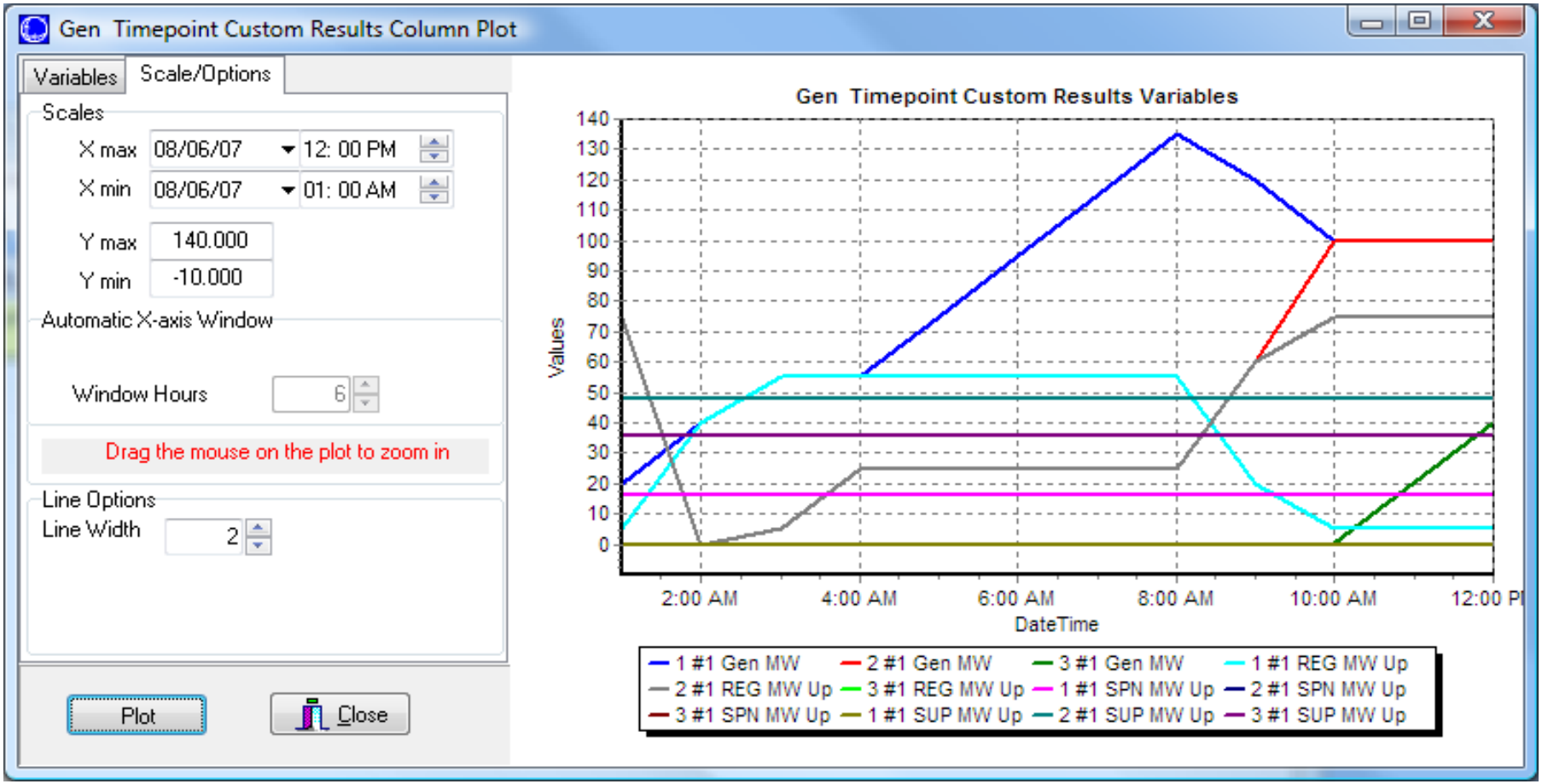
Generator hourly regulating reserve

Generator hourly spinning reserve

Generator hourly supplemental reserve

# TSS Reserve Simulations

- Using the column plot



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