ANNEX A

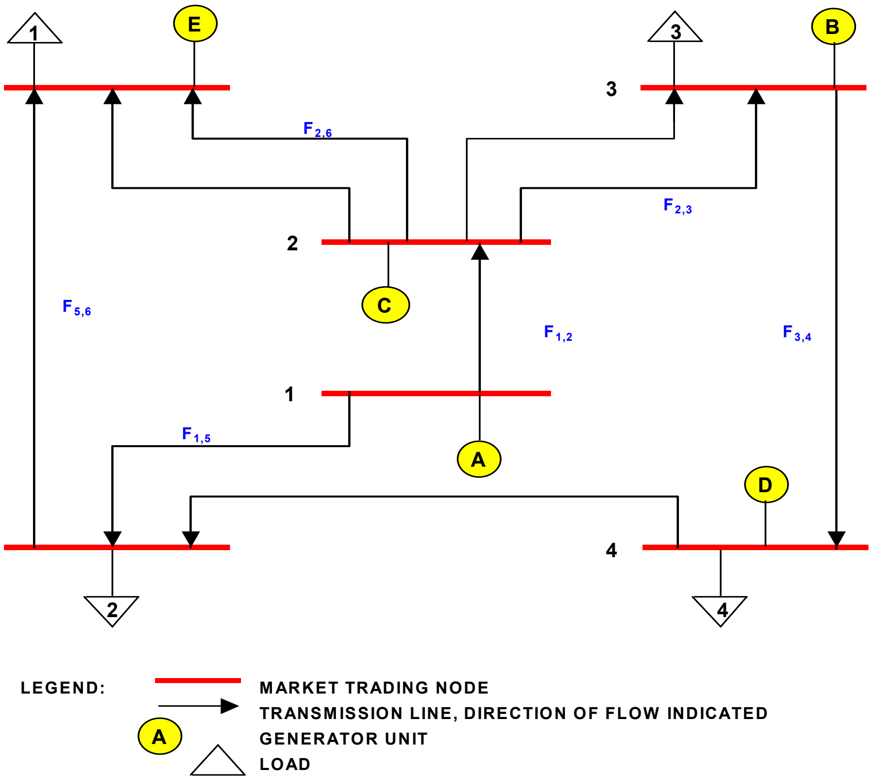
Comprehensive information and example using actual data detailing the relevance and application of each of the concepts of the PDM as mentioned in its original submission

1.0 Step-by-Step Illustration of the Optimization Process

The example below illustrates the optimization process of the pricing and dispatch algorithm of the Price Determination Methodology. The Six-Node Market Network Model shown in Figure A-1 is used as an example. The network characteristics are shown in Table A-1 while the energy and reserves requirement, demands bids, and generators energy and reserves offers are shown in Table A-2.

In this example, all scheduled load's facilities are assumed located in a single zone wherein a single Customer Pricing Zone (CPZ) is applied. The single zone is also equivalent to the reserve region.

Figure A-1.
Sample Six-Node Market Network Model
Single Line Diagram



The transmission lines are rated 350 MW per circuit and each line is represented by its direct current (DC) electrical characteristics, namely: line resistance (R), and line reactance (X).

The input data for the six-node MNM example, shown in Table A-2, has five generators competing to supply the four nodal loads, four demand bid blocks, and system reserves requirement.

Table A-1
Network Characteristic-Six Node MNM Example

Transmission Network Data
(Direct Current Representation)

From Node	To Node	Line Characteristics		Capacity
		Line R	Line X	MW
1	2	0.00870	0.06780	350
1	5	0.01350	0.10530	350
2	3	0.00315	0.02450	700
2	6	0.00165	0.01295	700
3	4	0.00220	0.01730	350
4	5	0.00330	0.02590	350
5	6	0.00180	0.01440	350

Note: R and X in per unit at MVA base, MW is actual capacity

Table A-2
Input Table-Six Node MNM Example

RESERVE REQUIREMENT			
REG. (MW)	3.0%	CONT (MW)	10.0%
	30		100

INPUT

NODE	TOTAL DEMAND	NET LOAD FORECAST	DEMAND BID		GEN CAP (MW)	GEN OFFER		REG RES. OFFER		CONT RES. OFFER	
			QTY (MW)	PRICE (P//MWh)		QTY (MW)	PRICE (P/MWh)	QTY (MW)	PRICE (P/MWh)	QTY (MW)	PRICE (P/MWh)
1	0.00	0.00	0.0	0.00	600.0	600.0	200.00	18.0	220.00	0.0	0.00
2	0.00	0.00	0.0	0.00	400.0	400.0	1421.43	12.0	426.43	50.0	821.43
3	330.00	300.00	30.0	1400.00	150.0	150.0	841.43	5.0	925.57	0.0	0.00
4	165.00	150.00	15.0	1700.00	300.0	300.0	1450.00	20.0	1530.47	50.0	2233.47
5	220.00	200.00	20.0	1900.00	0.0	0.0	0.00	0.0	0.00	0.0	0.00
6	385.00	350.00	35.0	1300.00	600.0	600.0	3098.48	20.0	1546.24	50.0	1049.24
TOTAL	**1100.00**	**1000.00**	**100.0**		**2050.0**	**2050.0**		**75.0**		**150.0**	

Case 1: Ex Ante Run: WESM Market Dispatch Optimization Model (Unconstrained Scenario)

A snap shot computation using the network characteristics in Table A-1 and input data in Table A-2 is shown below to demonstrate the computation internal to the optimization algorithm. Take note that actual computation is done iteratively until a solution is found. The sample computation below is presented in accordance with the optimization process flow shown in Annex C.

STEP 1. Initial optimization run

The process starts with an initial optimization run where the optimizer determines the appropriate combination of generator energy dispatch, co-optimized with reserves, to satisfy energy and reserves requirement and decides the quantity of demand bid to be served using the objective function and the constraint equations.

The solution wherein each quantity (i.e., energy, regulating, and contingency reserves) is taken from the generator stack, arranged in economic order, will result to a least-cost solution. The marginal price of energy is P1421.43/MWh set by Generator C connected at Node 2 which is the last plant to be dispatched. Similarly the price of regulating reserve is P426.43 set by Generator C and contingency reserve at P1049.24 set by Generator E.

Demand bid blocks at Nodes 3 and 6 were excluded since their price bids are lower than the marginal price of energy. Table A-3 shows the results of the initial optimization process.

Table A-3.
Results of Initial Optimization Run, Unconstrained Case

NODE	TOTAL DEM AND SERVED	NET LOAD FORECAST	SCHEDULED QUANTITIES							
			DEMAND BID		ENERGY		REG RESERVE		CONT RESERVE	
			QTY (MW)	COST (P)	QTY (MW)	COST (P)	QTY (MW)	COST (P)	QTY (MW)	COST (P)
1	0.00	0.00	0.0	0.00	582.000	116400.00	18.0	3960.00	0.0	0.00
2	0.00	0.00	0.0	0.00	303.000	430693.29	12.0	5117.16	50.0	41071.50
3	300.00	300.00	0.0	0.00	150.000	126214.50	0.0	0.00	0.0	0.00
4	165.00	150.00	15.0	25500.00	0.000	0.00	0.0	0.00	0.0	0.00
5	220.00	200.00	20.0	38000.00	0.000	0.00	0.0	0.00	0.0	0.00
6	350.00	350.00	0.0	0.00	0.000	0.00	0.0	0.00	50.0	52462.00
TOTAL	**1035.00**	**1000.00**	**35.0**	**63500.00**	**1035.000**	**673307.79**	**30.0**	**9077.2**	**100.0**	**93533.5**
					MARGINAL PRICES (P/MWh) >>		**REG**	**426.43**	**CONT**	**1049.24**

STEP 2. Computation of Line Flows and Line Losses

With the results of the initial optimization run, line flows and losses are computed. Line losses are added to the demand at each node depending on the direction of power flow, that is, losses are placed at the receiving end of the line. As the sum of demand and losses at each node is updated, a re-run of the optimization process is needed to update the generation schedules. The iterative process (i.e. continuous updating in Step 1 and Step 2) ends when a system balance is found. Results of the optimization run (with losses) are shown in Table A-7.

The computation of line flows and losses is based on DC Load Flow algorithm. Refer to Appendix A of Annex C for concepts of DC Load Flow. The net injection at a particular node is equal to the summation of line flows at that node. For the six-node example, the equations in matrix form is given by:

$$\begin{bmatrix} G_1 - D_1' \\ G_2 - D_2' \\ G_3 - D_3' \\ G_4 - D_4' \\ G_5 - D_5' \\ G_6 - D_6' \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} & Y_{14} & Y_{15} & Y_{16} \\ Y_{21} & Y_{22} & Y_{23} & Y_{24} & Y_{25} & Y_{26} \\ Y_{31} & Y_{32} & Y_{33} & Y_{34} & Y_{35} & Y_{36} \\ Y_{41} & Y_{42} & Y_{43} & Y_{44} & Y_{45} & Y_{46} \\ Y_{51} & Y_{52} & Y_{53} & Y_{54} & Y_{55} & Y_{56} \\ Y_{61} & Y_{62} & Y_{63} & Y_{64} & Y_{65} & Y_{66} \end{bmatrix} \begin{bmatrix} \phi_1 \\ \phi_2 \\ \phi_3 \\ \phi_4 \\ \phi_5 \\ \phi_6 \end{bmatrix}$$

where:

$Y_{ij} = -\frac{1}{X_{ij}}$ (off-diagonals of the admittance matrix)

$Y_{ii} = \sum_{j=1}^{N} \frac{1}{X_{ij}}$ (diagonals of the admittance matrix, N = number of nodes)

$G_1 - D_1'$ = net injection, generation less (demand plus losses)

ϕ_i = Node (bus) voltage angles

In algebraic equation format,

$$G_1 - D_1' = Y_{11} \bullet \phi_1 + Y_{12} \bullet \phi_2 + Y_{13} \bullet \phi_3 + Y_{14} \bullet \phi_4 + Y_{15} \bullet \theta_5 + Y_{16} \bullet \phi_6$$
$$G_2 - D_2' = Y_{21} \bullet \phi_1 + Y_{22} \bullet \phi_2 + Y_{23} \bullet \phi_3 + Y_{24} \bullet \phi_4 + Y_{25} \bullet \theta_5 + Y_{26} \bullet \phi_6$$
$$G_3 - D_3' = Y_{31} \bullet \phi_1 + Y_{32} \bullet \phi_2 + Y_{33} \bullet \phi_3 + Y_{34} \bullet \phi_4 + Y_{35} \bullet \theta_5 + Y_{36} \bullet \phi_6$$
$$G_4 - D_4' = Y_{41} \bullet \phi_1 + Y_{42} \bullet \phi_2 + Y_{43} \bullet \phi_3 + Y_{44} \bullet \phi_4 + Y_{45} \bullet \theta_5 + Y_{46} \bullet \phi_6$$
$$G_5 - D_5' = Y_{51} \bullet \phi_1 + Y_{52} \bullet \phi_2 + Y_{53} \bullet \phi_3 + Y_{54} \bullet \phi_4 + Y_{55} \bullet \theta_5 + Y_{56} \bullet \phi_6$$
$$G_6 - D_6' = Y_{61} \bullet \phi_1 + Y_{62} \bullet \phi_2 + Y_{63} \bullet \phi_3 + Y_{64} \bullet \phi_4 + Y_{65} \bullet \theta_5 + Y_{66} \bullet \phi_6$$

Table A-4.
Computed Admittance Matrix, Six-Node MNM Example

Y_{ij}	1	2	3	4	5	6
1	24.2459	-14.7493	0.0000	0.0000	-9.4967	0.0000
2	-14.7493	132.7857	-40.8163	0.0000	0.0000	-77.2201
3	0.0000	-40.8163	98.6198	-57.8035	0.0000	0.0000
4	0.0000	0.0000	-57.8035	96.4135	-38.6100	0.0000
5	-9.4967	0.0000	0.0000	-38.6100	117.5512	-69.4444
6	0.0000	-77.2201	0.0000	0.0000	-69.4444	146.6645

The system admittances (Y) shown in Table A-4 are computed using the given line reactances (X). Using the demand data, the system admittances, and the scheduled generation energy quantities found in step 1, the above equations can be solved using matrix inversion or elimination to determine the node (bus) voltage angles. The resulting node (bus) voltage angles are shown in Table A-5 below.

Table A-5
Computed Node Voltage Angles, in radians

Node Voltage Angles (Radians)					
ϕ_1	ϕ_2	ϕ_3	ϕ_4	ϕ_5	ϕ_6
0.292894	0.07438	0.01558	0.0000	0.01942	0.02449

Computation of Line Flows.

Compute the Line Flows using the calculated node voltage angles and system admittances. Note that all quantities are multiplied by 100 to convert per unit values to actual values.

$$F_{12} = (\varphi_1 - \varphi_2) \bullet Y_{12} = 322.29\ \text{MW}$$

$$F_{15} = (\varphi_1 - \varphi_5) \bullet Y_{15} = 259.71\ \text{MW}$$

$$F_{23} = (\varphi_2 - \varphi_3) \bullet Y_{23} = 240.00\ \text{MW}$$

$$F_{26} = (\varphi_2 - \varphi_6) \bullet Y_{26} = 385.25\ \text{MW}$$

$$F_{34} = (\varphi_3 - \varphi_4) \bullet Y_{34} = 90.06\ \text{MW}$$

$$F_{45} = (\varphi_4 - \varphi_5) \bullet Y_{45} = -74.98\ \text{MW}$$

$$F_{56} = (\varphi_5 - \varphi_6) \bullet Y_{56} = -35.21\ \text{MW}$$

Computation of Line Losses.

The line losses are function of the line flows and line characteristic (i.e., line resistance). Resistance data in Table A-1 are used in the following computation of line losses.

$$P_{ij} = \frac{F_{ij}^2 \bullet_{PU} R_{ij}}{MVA_B} \text{ (refer to Appendix A of Annex C for derivation of formula)}$$

$$P_{L(12)} = \frac{F_{12}^2 \bullet_{PU} R_{12}}{MVA_B} = 9.04\ \text{MW}$$

$$P_{L(15)} = \frac{F_{15}^{2} \bullet R_{15}}{MVA_{B}} = 9.11\,MW$$

$$P_{L(23)} = \frac{F_{23}^{2} \bullet_{PU} R_{23}}{MVA_{B}} = 1.81\,MW$$

$$P_{L(26)} = \frac{F_{26}^{2} \bullet_{PU} R_{26}}{MVA_{B}} = 2.45\,MW$$

$$P_{L(34)} = \frac{F_{34}^{2} \bullet_{PU} R_{34}}{MVA_{B}} = 0.19\,MW$$

$$P_{L(45)} = \frac{F_{45}^{2} \bullet_{PU} R_{45}}{MVA_{B}} = 0.19\,MW$$

$$P_{L(56)} = \frac{F_{56}^{2} \bullet_{PU} R_{56}}{MVA_{B}} = 0.02\,MW$$

where:

MVA_B = 100 MVA

Assign the computed losses to the receiving nodes as defined with respect to the direction of line flows.

Table A-6
Line Losses Node Allocation, Unconstrained Case

Nodal Losses							
NODE	1	2	3	4	5	6	TOTAL
LOSS	0.00	9.04	1.81	0.38	9.13	2.45	22.81

The updated solution of the optimization process is shown below. Note that the dispatch schedules and the nodal losses are the final values that will maintain a system balance. The results in Table A-7 will serve as the basis in determining the Nodal Price.

Table A-7
Optimization Results (Loss Updated), Unconstrained Scenario

NODE	TOT DEM SERVED	NET LOAD FORECAST	SCHEDULED QUANTITIES							
			DEMAND BID		ENERGY		REG RESERVE		CONT RESERVE	
			QTY (MW)	COST (P)	QTY (MW)	COST (P)	QTY (MW)	COST (P)	QTY (MW)	COST (P)
1	0.00	0.00	0.0	0.00	582.000	116400.00	18.0	3960.00	0.0	0.00
2	0.00	0.00	0.0	0.00	325.993	463376.23	12.0	5117.16	50.0	41071.50
3	300.00	300.00	0.0	0.00	150.000	126214.50	0.0	0.00	0.0	0.00
4	165.00	150.00	15.0	25500.00	0.000	0.00	0.0	0.00	0.0	0.00
5	220.00	200.00	20.0	38000.00	0.000	0.00	0.0	0.00	0.0	0.00
6	350.00	350.00	0.0	0.00	0.000	0.00	0.0	0.00	50.0	52462.00
TOTAL	**1035.00**	**1000.00**	**35.0**	**63500.00**	**1057.993**	**705990.23**	**30.0**	**9077.2**	**100.0**	**93533.5**
MARGINAL PRICES (P/MWh) >>							**REG**	**426.43**	**CONT**	**1049.24**

NODE	LOSS DISTRIBUTION
1	0.00
2	8.97
3	1.88
4	0.36
5	9.22
6	2.56
Total	**22.99**

STEP 3. Determination of Nodal Prices

Marginal price at a specific location is computed on the basis of the resulting marginal plants' contribution, in terms of cost, to an incremental load of one megawatt-hour occurring in that particular location or node. Mathematically, marginal price is given by:

$$\text{Marginal Price} = \sum \left[\frac{\Delta G_i}{\Delta D_j} \text{ x } P_i \right]$$

The resulting nodal marginal price is then multiplied by a loss factor to make adjustment to reflect the cost of transmission loss for that node. The result is the nodal price or locational marginal price. The transmission losses computed above are the basis for the computation of loss factors and are automatically computed in the optimization process referenced at the resulting marginal plant.

Nodal Price = Marginal Price X Marginal Loss Factor

As illustrated in Table A-8, if an increment of 1 MW is drawn from a certain node, say at Node 1, the marginal plant (Gen C at Node 2) will generate an amount corresponding to the incremental 1 MW load, for a total of 326.993 MW compared to a base output of 325.993 MW. The loss factor of Node 1, whose value from the table is 0.94, tells us that a reduction in system loss will result if an incremental load is drawn at Node 1 while being supplied from Node 2. The adjusted nodal price at Node 1 is then P1421.43 x 0.94 that is equal to P1341.65.

In summary loss factors less than 1.0 would mean reduction in loss and lower nodal price than the marginal price. Loss factors higher than 1.0 would mean higher losses and higher nodal price compared to the marginal plant.

Table A-8
Illustrative Computation of Nodal Prices, Unconstrained Scenario

NODE	BASE CASE DISPATCH	INCREMENT 1 MW AT NODE					
		1	2	3	4	5	6
		CHANGE IN GENERATOR OUTPUT IN MW					
1	582.000	582.000	582.000	582.000	582.000	582.000	582.000
2	325.993	326.993	326.993	326.993	326.993	326.993	326.993
3	150.000	150.000	150.000	150.000	150.000	150.000	150.000
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	PRICE OFFER	**INCREMENTAL ENERGY COST IN P/MWh**					
1	200.00	0.000	0.000	0.000	0.000	0.000	0.000
2	1421.43	1421.430	1421.430	1421.430	1421.430	1421.430	1421.430
3	841.43	0.000	0.000	0.000	0.000	0.000	0.000
4	1450.00	0.000	0.000	0.000	0.000	0.000	0.000
5	0.00	0.000	0.000	0.000	0.000	0.000	0.000
6	3098.48	0.000	0.000	0.000	0.000	0.000	0.000
NP>	**SUMMATION**	**1421.430**	**1421.430**	**1421.430**	**1421.430**	**1421.430**	**1421.430**
	LOSS FACTOR	0.94387364	0.99999989	1.01563768	1.01977842	1.01484369	1.01325106
	ADJ. NODAL PRICES	**1341.650**	**1421.430**	**1443.658**	**1449.544**	**1442.529**	**1440.265**

STEP 4: Comparison of Demand Bids with Nodal Prices

Demand Bid Check: For a Demand Bid to be scheduled, Demand Bid Price (CDB) must be greater than the Nodal Price where DB is connected.

Table A-9.
Demand Bid Check

DEMAND BID			ADJ. NODAL PRICE	DEMAND BID> NODAL PRICE
OFFER		SCHEDULE		
QTY	COST	QTY		
(MW)	(P/MWh)	(MW)	(P/MWh)	
0	0	0	1341.65	FAIL
0	0	0	1421.43	FAIL
30	1400	0	1443.66	FAIL
15	1700	15	1449.54	PASS
20	1900	20	1442.53	PASS
35	1300	0	1440.27	FAIL

Scheduled demand bids failing the demand bid check will be excluded and the whole process (from Step 1) will be repeated until all scheduled demand bids pass the demand bid check.

Final Results of the Optimization Run

The generation schedules, served demand bids, nodal prices, customer zonal and reserves prices are summarized in Table A-10. The nodal losses, loss factors, and the resulting power flows are summarized in Table A-10 and shown in detail in Table A-11. Figure A-2 shows all the optimization results in diagram format.

Table A-10
Final Optimization Results, Unconstrained Scenario

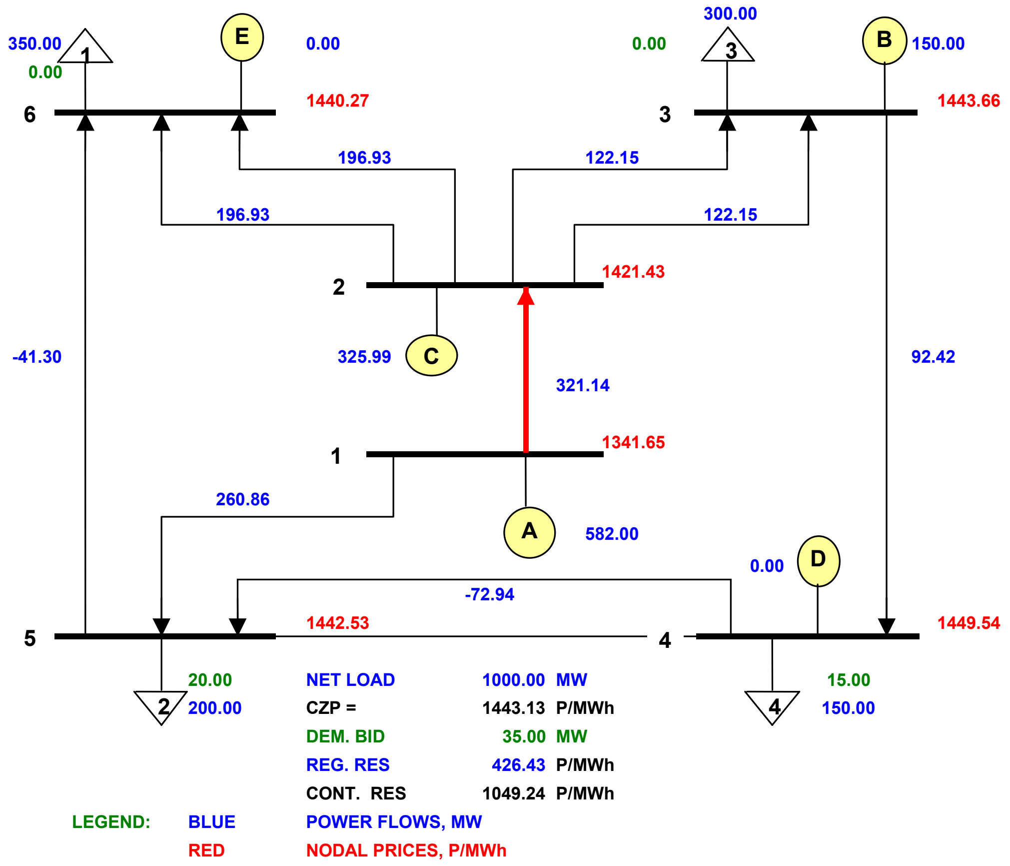
NODE	TOT DEM SERVED	NET LOAD FORECAST	SCHEDULED QUANTITIES							
			DEMAND BID		ENERGY		REG RESERVE		CONT RESERVE	
			QTY (MW)	COST (P)	QTY (MW)	COST (P)	QTY (MW)	COST (P)	QTY (MW)	COST (P)
1	0.00	0.00	0.0	0.00	582.000	116400.00	18.0	3960.00	0.0	0.00
2	0.00	0.00	0.0	0.00	325.993	463376.23	12.0	5117.16	50.0	41071.50
3	300.00	300.00	0.0	0.00	150.000	126214.50	0.0	0.00	0.0	0.00
4	165.00	150.00	15.0	25500.00	0.000	0.00	0.0	0.00	0.0	0.00
5	220.00	200.00	20.0	38000.00	0.000	0.00	0.0	0.00	0.0	0.00
6	350.00	350.00	0.0	0.00	0.000	0.00	0.0	0.00	50.0	52462.00
TOTAL	**1035.00**	**1000.00**	**35.0**	**63500.00**	**1057.993**	**705990.23**	**30.0**	**9077.2**	**100.0**	**93533.5**
						MARGINAL PRICES (P/MWh) >>	**REG**	**426.43**	**CONT**	**1049.24**

NODE	NODAL PRICE (P/MWh)	LOSS DISTRIBUTION	LOSS FACTOR	LOAD ADJ. NODAL PRICE (P/MWh)
1	1421.43	0.00	0.94387	1341.650
2	1421.43	8.97	1.00000	1421.430
3	1421.43	1.88	1.01564	1443.658
4	1421.43	0.36	1.01978	1449.544
5	1421.43	9.22	1.01484	1442.529
6	1421.43	2.56	1.01325	1440.265
TOTAL		**22.99**	**CPZ**	**1443.128**

Table A-11.
Power Flow Table, Unconstrained Scenario

From	To	Ckt	Line Capacity	Line Flows				R	Line Loss, MW	Allocated to
				ϕI	ϕj	Yij	Flows, MW			
1	2	1	350	0.29358	0.07584	14.7493	321.14	0.0087	8.97	Node 2
1	5	1	350	0.29358	0.01889	9.4967	260.86	0.0135	9.19	Node 5
2	3	1 & 2	700	0.07584	0.01599	40.8163	244.30	0.0032	1.88	Node 3
2	6	1 & 2	700	0.07584	0.02484	77.2201	393.86	0.0017	2.56	Node 6
3	4	1	350	0.01599	0.00000	57.8035	92.42	0.0022	0.19	Node 4
4	5	1	350	0.00000	0.01889	38.6100	-72.94	0.0033	0.18	Node 4
5	6	1	350	0.01889	0.02484	69.4444	-41.30	0.0018	0.03	Node 5
								System Loss	**22.99**	

Figure A-2. Power Flow, Unconstrained Scenario



Case 2: Ex-Post Run: WESM Market Dispatch Optimization Model (Constrained Scenario)

The same set of network parameters, generator and load data were used in the ex-post run. To reflect a constrained scenario, an operational problem is simulated by reducing the capacity of the line from node 1 to node 2 (L_{12}) from 350 MW to 250 MW.

STEP 1. Initial Optimization Run

Since the capacity of the line that connects node 1 and node 2 (L_{12}) was reduced from 350 MW to 250 MW, the optimizer will observe this line constraint and will not allow generation schedules that will result to overloading of the line. Because of this constraint, Generator A at node 1 was not able to generate at its maximum capacity and therefore Generator D at node 4 which is the next available plant in the generator stack would have to generate correspondingly to meet the requirements of the system. Note that in this scenario, there are now at least two marginal plants that will set the nodal prices. Results of the optimization runs before and after loss calculation are shown in Table A-13 and Table A-16, respectively. The results in Table A-16 will serve as the basis for determining the nodal prices.

Table A-13
Results of Initial Optimization Run, Constrained Scenario

NODE	TOT DEM SERVED	NET LOAD FORECAST	METERED QUANTITIES			
			DEMAND BID		ENERGY	
			QTY (MW)	COST (P)	QTY (MW)	COST (P)
1	0.00	0.00	0.0	0.00	462.268	92453.60
2	0.00	0.00	0.0	0.00	338.000	480443.34
3	300.00	300.00	0.0	0.00	150.000	126214.50
4	165.00	150.00	15.0	25500.00	84.732	122861.43
5	220.00	200.00	20.0	38000.00	0.000	0.00
6	350.00	350.00	0.0	0.00	0.000	0.00
TOTAL	**1035.00**	**1000.00**	**35.0**	**63500.00**	**1035.0**	**821972.9**

STEP 2. Computation of Line Flows and line Losses

Compute for bus voltage angles using the same admittance matrix in Table A-4 and generation schedule in Table A-13. The resulting node (bus) voltage angles are shown in Table A-14.

$$G_1 - D_1' = Y_{11} \bullet \phi_1 + Y_{12} \bullet \phi_2 + Y_{13} \bullet \phi_3 + Y_{14} \bullet \phi_4 + Y_{15} \bullet \theta_5 + Y_{16} \bullet \phi_6$$
$$G_2 - D_2' = Y_{21} \bullet \phi_1 + Y_{22} \bullet \phi_2 + Y_{23} \bullet \phi_3 + Y_{24} \bullet \phi_4 + Y_{25} \bullet \theta_5 + Y_{26} \bullet \phi_6$$
$$G_3 - D_3' = Y_{31} \bullet \phi_1 + Y_{32} \bullet \phi_2 + Y_{33} \bullet \phi_3 + Y_{34} \bullet \phi_4 + Y_{35} \bullet \theta_5 + Y_{36} \bullet \phi_6$$
$$G_4 - D_4' = Y_{41} \bullet \phi_1 + Y_{42} \bullet \phi_2 + Y_{43} \bullet \phi_3 + Y_{44} \bullet \phi_4 + Y_{45} \bullet \theta_5 + Y_{46} \bullet \phi_6$$
$$G_5 - D_5' = Y_{51} \bullet \phi_1 + Y_{52} \bullet \phi_2 + Y_{53} \bullet \phi_3 + Y_{54} \bullet \phi_4 + Y_{55} \bullet \theta_5 + Y_{56} \bullet \phi_6$$
$$G_6 - D_6' = Y_{61} \bullet \phi_1 + Y_{62} \bullet \phi_2 + Y_{63} \bullet \phi_3 + Y_{64} \bullet \phi_4 + Y_{65} \bullet \theta_5 + Y_{66} \bullet \phi_6$$

Table A-14
Node Voltage Angles, in radians

Node Voltage Angles (Radians)					
ϕ_1	ϕ_2	ϕ_3	ϕ_4	ϕ_5	ϕ_6
0.22975	0.06025	0.00973	0.0000	0.00623	0.01081

Computation of Line Flows

Note that power flowing along L_{12} is limited to the line capacity (i.e. 250 MW) due to operational problem encountered during the actual implementation of the Ex-ante schedule. Note that all quantities are multiplied by 100 to convert per unit values to actual values.

$$F_{12} = (\varphi_1 - \varphi_2) \bullet Y_{12} = 250.00\,\text{MW}$$

$$F_{15} = (\varphi_1 - \varphi_5) \bullet Y_{15} = 212.27\,\text{MW}$$

$$F_{23} = (\varphi_2 - \varphi_3) \bullet Y_{23} = 206.20\,\text{MW}$$

$$F_{26} = (\varphi_2 - \varphi_6) \bullet Y_{26} = 381.78\,\text{MW}$$

$$F_{34} = (\varphi_3 - \varphi_4) \bullet Y_{34} = 56.24\,\text{MW}$$

$$F_{45} = (\varphi_4 - \varphi_5) \bullet Y_{45} = -24.05\,\text{MW}$$

$$F_{56} = (\varphi_5 - \varphi_6) \bullet Y_{56} = -31.81\,\text{MW}$$

Computation of Line Losses

The computed line losses are allocated to the receiving nodes in the direction of the power flows. Refer to Table A-15 for loss allocation. Repeated updating of values in Step 1 and Step 2 is done until system balance is attained. Table A-16 shows the optimization solution when loss is updated and system balance is attained.

$$P_{L(12)} = \frac{F_{12}^2 \bullet {}_{PU}R_{12}}{MVA_B} = 5.44\,\text{MW}$$

$$P_{L(15)} = \frac{F_{15}^2 \bullet {}_{PU}R_{15}}{MVA_B} = 6.08\,\text{MW}$$

$$P_{L(23)} = \frac{F_{23}^2 \bullet {}_{PU}R_{23}}{MVA_B} = 1.34\,\text{MW}$$

$$P_{L(26)} = \frac{F_{26}^2 \bullet {}_{PU}R_{26}}{MVA_B} = 2.40\,\text{MW}$$

$$P_{L(34)} = \frac{F_{34}^2 \bullet {}_{PU}R_{34}}{MVA_B} = 0.07\,\text{MW}$$

$$P_{L(45)} = \frac{F_{45}^2 \bullet {}_{PU}R_{45}}{MVA_B} = 0.02\,\text{MW}$$

$$P_{L(56)} = \frac{F_{56}^2 \bullet {}_{PU}R_{56}}{MVA_B} = 0.02\,\text{MW}$$

Table A-15
Line Loss Node Allocation, Constrained Scenario

Nodal Losses (MW)							
NODE	**1**	**2**	**3**	**4**	**5**	**6**	**TOTAL**
LOSS	**0.00**	**5.44**	**1.34**	**0.09**	**6.10**	**2.40**	**15.37**

Table A-16
Optimization Results (Loss Updated), Constrained Case

NODE	TOT DEM SERVED	NET LOAD FORECAST	METERED QUANTITIES			
			DEMAND BID		ENERGY	
			QTY (MW)	COST (P)	QTY (MW)	COST (P)
1	0.00	0.00	0.0	0.00	461.974	92394.82
2	0.00	0.00	0.0	0.00	338.000	480443.34
3	300.00	300.00	0.0	0.00	150.000	126214.50
4	165.00	150.00	15.0	25500.00	100.281	145407.98
5	220.00	200.00	20.0	38000.00	0.000	0.00
6	350.00	350.00	0.0	0.00	0.000	0.00
TOTAL	**1035.00**	**1000.00**	**35.0**	**63500.00**	**1050.255**	**844460.64**

NODE	LOSS DISTRIBUTION
1	0.00
2	5.44
3	1.27
4	0.06
5	6.08
6	2.41
TOTAL	**15.26**

STEP 3. Determination of Nodal Prices

Marginal price at a specific location is computed on the basis of the resulting marginal plants' contribution, in terms of cost, to an incremental load of one megawatt-hour occurring in that particular location or node. Mathematically, marginal price is given by:

$$\text{Marginal Price} = \sum \left[\frac{\Delta G_i}{\Delta D_j} \text{ x } P_i \right]$$

With the presence of line constraint due to the operational problem experienced in line L_{12}, the optimizer found a solution with a binding constraint between nodes 1 and 2. In effect, two pricing sub-zones are created where the nodal prices in each sub-zone are set by different marginal generators.

As shown in Table A-17, Generator A connected at node 1 and Generator D connected at node 4 are the marginal generators contributing to the nodal price computed by drawing an incremental MW at a particular node.

Referring to Table A-17, if an incremental MW is drawn at node 1, generator A at node 1 will supply the requirement. This can be computed by getting the difference in the generation schedule of each plant, i.e., subtract column (Base Case Dispatch) from column (1). Marginal plants contribution to the incremental MW drawn at other nodes can be computed using the same procedure.

The summation of all marginal plant contribution to the incremental MW, in terms of cost (i.e. MW contribution x offer price), will be the basis for setting the nodal prices.

Table A-17
Illustrative Computation of Nodal Prices, Constrained Scenario

NODE	BASE CASE DISPATCH	INCREMENT 1 MW AT NODE					
		1	**2**	**3**	**4**	**5**	**6**
		CHANGE IN GENERATOR OUTPUT IN MW					
1	461.974	462.974	461.867	461.930	461.974	462.040	461.949
2	338.000	338.000	338.000	338.000	338.000	338.000	338.000
3	150.000	150.000	150.000	150.000	150.000	150.000	150.000
4	100.281	100.281	101.388	101.326	101.281	101.215	101.306
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	PRICE OFFER	**INCREMENTAL ENERGY COST IN P/MWh**					
1	200.00	200.000	-21.335	-8.830	0.000	13.219	-4.974
2	1421.43	0.000	0.000	0.000	0.000	0.000	0.000
3	841.43	0.000	0.000	0.000	0.000	0.000	0.000
4	1450.00	0.000	1604.676	1514.017	1450.000	1354.160	1486.059
5	0.00	0.000	0.000	0.000	0.000	0.000	0.000
6	3098.48	0.000	0.000	0.000	0.000	0.000	0.000
NP>	**SUMMATION**	**200.000**	**1583.341**	**1505.187**	**1450.000**	**1367.379**	**1481.085**
	LOSS FACTOR	1.00000017	0.98083732	0.99564376	1.00000000	1.00270487	0.99654571
	ADJ. NODAL PRICES	**200.000**	**1553.000**	**1498.630**	**1450.000**	**1371.078**	**1475.969**

Final Results of the Optimization Run

Table A-18
Complete Optimization Results, Constrained Case

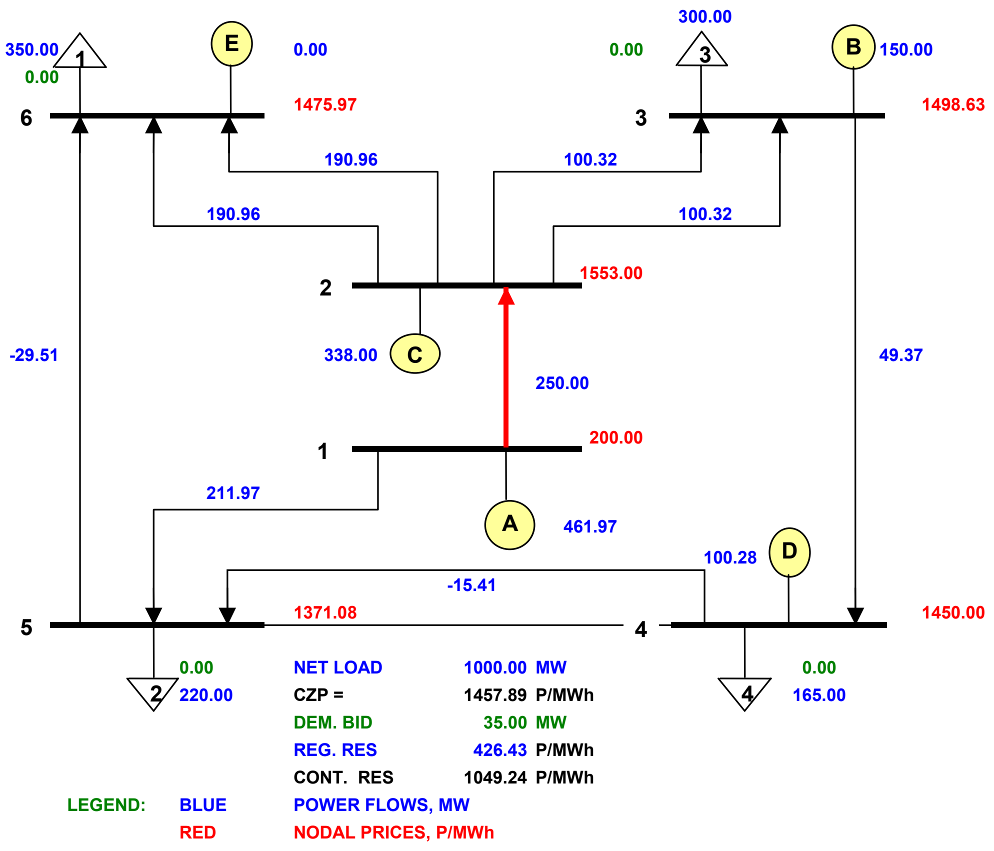
NODE	TOT DEM SERVED	NET LOAD FORECAST	METERED QUANTITIES			
			DEMAND BID		ENERGY	
			QTY (MW)	COST (P)	QTY (MW)	COST (P)
1	0.00	0.00	0.0	0.00	461.974	92394.82
2	0.00	0.00	0.0	0.00	338.000	480443.34
3	300.00	300.00	0.0	0.00	150.000	126214.50
4	165.00	150.00	15.0	0.00	100.281	145407.98
5	220.00	200.00	20.0	25500.00	0.000	0.00
6	350.00	350.00	0.0	38000.00	0.000	0.00
TOTAL	**1035.00**	**1000.00**	**35.0**	**63500.00**	**1050.255**	**844460.64**

NODE	NODAL PRICE (P/MWh)	LOSS DISTRIBUTION	LOSS FACTOR	LOSS ADJ. NODAL PRICE (P/MWh)
1	200.000	0.00	1.0000	200.000
2	1583.341	5.44	0.9808	1553.000
3	1505.187	1.27	0.9956	1498.630
4	1450.000	0.06	1.0000	1450.000
5	1367.379	6.08	1.0027	1371.078
6	1481.085	2.41	0.9965	1475.969
TOTAL		**15.26**	**CPZ**	**1457.894**

Table A-19
Power Flow Table, Constrained Scenario

From	To	Ckt	Line Capacity	Line Flows				R	Line Loss, MW	Allocated to
				ϕi	ϕj	Yij	Flows, MW			
1	2	1	250	0.22720	0.05770	14.74926	250.00	0.0087	5.44	Node 2
1	5	1	350	0.22720	0.00399	9.496676	211.97	0.0135	6.07	Node 5
2	3	1 & 2	700	0.05770	0.00854	40.81633	200.64	0.0032	1.27	Node 3
2	6	1 & 2	700	0.05770	0.00824	77.22008	381.92	0.0017	2.41	Node 6
3	4	1	350	0.00854	0.00000	57.80347	49.37	0.0022	0.05	Node 4
4	5	1	350	0.00000	0.00399	38.61004	-15.41	0.0033	0.01	Node 4
5	6	1	350	0.00399	0.00824	69.44444	-29.51	0.0018	0.02	Node 5
								System Loss	**15.26**	

Figure A-3
Power Flows, Constrained Scenario



Constrained line is Line 1 to 2 from 350 MW to 250 MW capacity

2.0 Settlement

The aggregate trading amount for each participant is the sum of the following charges:

2.1 Ex-Ante Energy Trading Amount
2.2 Ex-Post Energy Trading Amount
2.3 Regulating Reserve Trading Amount
2.4 Contingency Reserve Trading Amount
2.5 Transmission Rights Trading Amount
minus
2.6 Line Rental Trading Amount
2.7 Regulating Reserve Cost Recovery Charge
2.8 Contingency Reserve Cost Recovery Charge

2.1 Ex-Ante Energy Trading Amount

$$\mathbf{EAETA_{k,h}^{m} = \Sigma(EAESP_{h}^{m} \; x \; (EAQSI_{k,h}^{m} - BCQ_{k,b,\,h}^{m}))}$$

Where:

$EAETA_{k,h}^{m}$	represents the ex-ante energy trading amount for participant "k" at Trading Interval "h" and metering point "m";
$EAESP_{h}^{m}$	is the ex-ante energy settlement price for the Trading Interval "h" and metering point "m", which is necessarily the market clearing price for the trading node where the generator is connected;
$EAQSI_{k,h}^{m}$	is the ex-ante quantity of energy that is supplied/withdrawn by the participant "k" for Trading Interval "h" and metering point "m"; and
$BCQ_{k,b,h}^{m}$	is the bilateral contract quantity associated with generator "k", and the corresponding buyer or customer "b" for Trading Interval "h" and metering point "m".

2.2 Ex-Post Energy Trading Amount

$$\mathbf{EPETA_{k,h}^{m}=\Sigma(EPESP_{h}^{m} x \; ((AQEI_{k,h}^{m} - EAQOM_{k,h}^{m}) - BCQ_{k,b,h}^{m})}$$

Where:

$EPETA_{k,h}^{m}$	is the ex-post energy trading amount for participant "k" at Trading Interval "h" and metering point "m";
$EPESP_{h}^{m}$	is the ex-post energy settlement price in Trading Interval "h" and metering point "m" which is necessarily the *market clearing price* in the ex-post market for the trading node where the generator is connected;
$AQEI_{k,h}^{m}$	is the actual quantity of energy injected/withdrawn by participant "k" at Trading Interval "h" and metering point "m";
$EAQOM_{k,h}^{m}$	is the ex-ante energy quantity scheduled (net of bilateral quantity) in the market for injection/withdrawal by participant "k", at Trading Interval "h" and metering point "m".

$$\mathbf{= (EAQSI_{k,h}^{m} - BCQ_{k,b,h}^{m})}$$

$BCQ_{k,b,h}^{m}$ is the bilateral contract quantity associated with buyer/customer "k", and the corresponding generator "b" for Trading Interval "h" and metering point "m".

2.3 Regulating Reserve Trading Amount

Computation is shown in the following formula. Since the regulating reserve energy is determined during actual implementation of dispatch (ex-post), the energy quantity and price is based on ex-post optimization run. The working formula would be:

$$\mathbf{RRTA_{k,h}^{m} = EPESP_{h}^{m} \times EPREQ_{k,h}^{m}}$$

where:

$RRTA_{k,h}^{m}$ is the ex-post regulating reserve energy trading amount of ancillary service provider "k" , at trading interval "h" and metering point "m"

$EPESP_{h}^{m}$ is the ex-post energy settlement price in Trading Interval "h" and metering point "m" which is necessarily the *market clearing price* in the ex-post market for the trading node where the generator (ancillary service provider) is connected;

$EPREQ_{k,h}^{m}$ is the actual regulating reserve energy contributed by ancillary service provider "k", at trading interval "h" and metering point "m"

2.4 Contingency Reserve Trading Amount

Computation is shown in the following formula. Since the contingency reserve energy is determined during actual implementation of dispatch (ex-post), the energy quantity and price is based on ex-post optimization run. The working formula would be:

$$\mathbf{CRTA_{k,h}^{m} = EPESP_{h}^{m} \times EPCEQ_{k,h}^{m}}$$

where:

$CRTA_{k,h}^{m}$ is the ex-post contingency reserve energy trading amount of ancillary service provider "k" , at trading interval "h" and metering point "m"

$EPESP_{h}^{m}$ is the ex-post energy settlement price in Trading Interval "h" and metering point "m" which is necessarily the *market clearing price* in the ex-post market for the trading node where the generator (ancillary service provider) is connected;

$EPCEQ_{k,h}^{m}$	is the actual contingency reserve energy contributed by ancillary service provider “k”, at trading interval “h” and metering point “m”

2.5 Transmission Right Trading Amount

$$\mathbf{FTR} = \mathbf{MW} \times [(P_R \times (1 - \%Loss)] - P_S)$$

where:

MW	is the contracted transmission right capacity
P_R	is the ex-ante nodal price at the receiving node
%Loss	is the agreed loss differential for the transmission right
P_S	is the ex-ante nodal price at sending node

2.6 Line Rental Trading Amount

$$\mathbf{LR} = (P_R \times Q_R) - (P_S \times Q_R)$$

Where:

P_R	is the ex-ante nodal price at the receiving node
P_S	is the ex-ante nodal price at sending node
Q_R	is the expected (ex-ante) quantity of flow out of the receiving node
Q_S	is the expected (ex-ante) quantity of flow into the sending node

2.7 Regulating Reserve Cost Recovery Charge

The cost of regulating reserve in each cost recovery zone shall be recovered from customers and generators whose facilities are connected in the specific reserve cost recovery zone in proportion to their individual weighted energy transaction volume.

The total cost associated to regulating reserve is given by:

$$\mathbf{RRC_h = RRQ_h \times RRP_h}$$

The regulating reserve cost recovery charge for each participant is in accordance with the following:

$$\mathbf{RRCRC_h} = \frac{1}{2} \times \mathbf{RRC_h} \times \frac{\mathbf{AQEI_{k,h}^{m}}}{\sum \mathbf{AQEI_h}} \text{ for generators}$$

and

$$\mathbf{RRCRC_h} = \frac{1}{2} \times \mathbf{RRC_h} \times \frac{\mathbf{AQEW_{k,h}^{m}}}{\sum \mathbf{AQEW_h}} \text{ for load and demand bids}$$

where :

RRC_h	is the cost of regulating reserve at trading interval “h”
RRQ_h	is the total regulating reserve quantity allocated to the reserve region to meet its requirement for the trading interval “h”.
RRP_h	is the Regulating Reserve Marginal Price based on the cleared ex-ante regulating reserve settlement price for the trading interval “h”
$RRCRC_h$	Regulating Reserve Cost Recovery Charge for the trading interval “h”
$AQEI_{k,h}^m$	is the actual quantity of energy injected by participant “k” at Trading Interval “h” and metering point “m”;
$AQEW_{k,h}^m$	is the actual quantity of energy withdrawn by participant “k” at Trading Interval “h” and metering point “m”;
$\Sigma AQEI_h$	is the total quantity of energy injected by all participants at Trading Interval “h”
$\Sigma AQEW_h$	is the total quantity of energy withdrawn by all participants at Trading Interval “h”

2.8 Contingency Reserve Cost Recovery Charge

The cost of contingency reserve in each cost recovery zone shall be recovered from generating companies who are connected in that reserve zone.

The total cost associated to contingency reserve is given by:

$$\mathbf{CRC_h = CRQ_h \text{ x } CRP_h}$$

The contingency reserve cost recovery charge for each generating company is in accordance with the following:

$$\mathbf{CRCRC_h = CRC_h \text{ x } \frac{AQEI_{k,h}^m}{\sum AQEI_h}}$$

where :

CRC_h	is the cost of contingency reserve at trading interval “h”
CRQ_h	is the total contingency reserve quantity allocated to the reserve region to meet its requirement for the trading interval “h”.
CRP_h	is the Contingency Reserve Marginal Price based on the cleared ex-ante contingency reserve settlement price for the trading interval “h”
$CRCRC_h$	Contingency Reserve Cost Recovery Charge for the trading interval “h”
$AQEI_{k,h}^m$	is the actual quantity of energy injected by participant “k” at Trading Interval “h” and metering point “m”;

$\Sigma AQEI_h$ is the total quantity of energy injected by all participants at Trading Interval “h”

Sample Settlement Computation

A. Without Bilateral Contract

Table A-20 Settlement without Bilateral Contract

ENERGY TRADING AMOUNT									
		EX-ANTE				EX-POST			
GENERATORS		EAESP	EAQSI	BCQ	EAETA	EPESP	AQEI	EAQOM	EPETA
NODE	ID	P/MWh	MW	MW	P	P/MWh	MW	MW	P
1	GEN A	1341.65	582	0	**780840.30**	200.00	462.0	582	**-24000.00**
2	GEN C	1421.43	326	0	**463386.18**	1553.00	338.0	326	**18636.00**
3	GEN B	1443.66	150	0	**216549.00**	1498.63	150.0	150	**0.00**
4	GEN D	1449.54	0	0	**0.00**	1450.00	100.3	0	**145435.00**
6	GEN E	1440.27	0	0	**0.00**	1475.97	0.0	0	**0.00**
SUB TOTAL			1058	0	1460775.48		1050.3	1058	140071.00

		EX-ANTE				EX-POST			
LOAD		EAESP	EAQSI	BCQ	EAETA	EPESP	AQEI	EAQOM	EPETA
NODE	ID	P/MWh	MW	MW	P	P/MWh	MW	MW	P
3	LOAD 3	1443.13	300	0	**432939.00**	1457.89	300	300	**0**
4	LOAD 4	1443.13	150	0	**216469.50**	1457.89	150	150	**0**
5	LOAD 2	1443.13	200	0	**288626.00**	1457.89	200	200	**0**
6	LOAD 1	1443.13	350	0	**505095.50**	1457.89	350	350	**0**
SUB TOTAL			1000	0	1443130.00		1000	1000	0

		EX-ANTE				EX-POST			
DEMAND BIDS		EAESP	EAQSI	BCQ	EAETA	EPESP	AQEI	EAQOM	EAQOM
NODE	ID	P/MWh	MW	MW	P	P/MWh	MW	MW	P
4	D BID 1	1449.54	15	0	**21743.10**	1450.00	15.0	15.0	**0.00**
5	D BID 2	1442.53	20	0	**28850.60**	1371.08	20.0	20.0	**0.00**
SUB TOTAL			35.00	0.00	50593.70		35.00	35.00	0.00

RESERVE COST RECOVERY CHARGE								
TRADING PART.			REG. RESERVE CHARGE			CONTIN. RESERVE CHARGE		
GENERATOR		AQEI	RRQ	RRP	RRC	CRQ	CRP	CRC
NODE	ID	MW	MW	P/MW	P	MW	P/MW	P
1	GEN A	462	6.6	426.43	2814.44	44	1049.24	46166.56
2	GEN C	338	4.8	426.43	2046.86	32.2	1049.24	33785.53
3	GEN B	150	2.2	426.43	938.15	14.3	1049.24	15004.13
4	GEN D	100.3	1.4	426.43	597.00	9.5	1049.24	9967.78
6	GEN E	0	0	426.43	0.00	0	1049.24	0.00
SUB TOTAL		1050.3	15		6396.45	100		104924.00
			REG. RESERVE CHARGE					
LOAD		AQEW	RRQ	RRP	RRC			
NODE	ID	MW	MW	P/MW	P			
3	LOAD 3	300	4.35	426.43	1854.97			
4	LOAD 4	150	2.17	426.43	925.35			
5	LOAD 2	200	2.9	426.43	1236.65			
6	LOAD 1	350	5.07	426.43	2162.00			
SUB TOTAL		1000	14.5		6178.97			
			REG. RESERVE CHARGE					
DEMAND BIDS		AQEW	RRQ	RRP	RRC			
NODE	ID	MW	MW	P/MW	P			
4	D BID 1	15	0.22	426.43	93.81			
5	D BID 2	20	0.29	426.43	123.66			
SUB TOTAL		35	0.5		217.47			

AGGREGATE TRADING AMOUNT FOR PARTICIPANTS

GENERATOR	GEN. A	GEN. B	GEN. C	GEN. D	GEN. E
EX-ANTE ENERGY TRADING AMOUNT	780840.30	216549.00	463386.18	0.00	0.00
EX-POST ENERGY TRADING AMOUNT	-24000.00	0.00	18636.00	145435.00	0.00
REGULATING RESERVE TRADING AMOUNTS	0.00	0.00	0.00	0.00	0.00
CONTINGENCY RESERVE TRADING AMOUNTS	0.00	0.00	0.00	0.00	0.00
TRANSMISSION RIGHT TRADING AMOUNTS	0.00	0.00	0.00	0.00	0.00
LINE RENTAL TRADING AMOUNTS	0.00	0.00	0.00	0.00	0.00
REGULATING RESERVE COST RECOVERY CHARGE *	7675.20	0.00	5117.16	0.00	0.00
	-2814.44	-938.15	-2046.86	-597.00	0.00
CONTINGENCY RESERVE COST RECOVERY CHARGE *	0.00	0.00	52462.00	0.00	52462.00
	-46166.56	-15004.13	-33785.53	-9967.78	0.00
TOTAL	**715534.50**	**200606.72**	**503768.95**	**134870.22**	**52462.00**

LOAD	LOAD 1	LOAD 2	LOAD 3	LOAD 4
EX-ANTE ENERGY TRADING AMOUNT	505095.50	288626.00	432939.00	216469.50
EX-POST ENERGY TRADING AMOUNT	0.00	0.00	0.00	0.00
TRANSMISSION RIGHT TRADING AMOUNTS	0.00	0.00	0.00	0.00
LINE RENTAL TRADING AMOUNTS	0.00	0.00	0.00	0.00
REGULATING RESERVE COST RECOVERY CHARGE	2162.00	1236.65	1854.97	925.35
TOTAL	**507257.50**	**289862.65**	**434793.97**	**217394.85**

DEMAND BIDS	DEMAND BID 1	DEMAND BID 2
ENERGY TRADING AMOUNT FOR DEMAND BIDDER	21743.10	28850.60
REGULATING RESERVE COST RECOVERY CHARGE	93.81	123.66
TOTAL	**21836.91**	**28974.26**

B. Bilateral Contract

Assuming that Generator A has a bilateral contract with Load 4 for 50MWh and has availed 40 MWh capacity for transmission right with the agreed loss differential for the transmission right of 3%, the computation for Generator A and Load 4 Energy Adjustments, Financial Rights and Line Rental settlement are as follows:

Table A-21. Settlement with Bilateral Contract

ENERGY TRADING AMOUNT									
		EX-ANTE				EX-POST			
GENERATORS		**EAESP**	**EAQSI**	**BCQ**	**EAETA**	**EPESP**	**AQEI**	**EAQOM**	**EPETA**
NODE	**ID**	**P/MWh**	**MW**	**MW**	**P**	**P/MWh**	**MW**	**MW**	**P**
1	GEN A	1341.65	582	50	**713757.80**	200.00	462.0	532	**-24000.00**
2	GEN C	1421.43	326	0	**463386.18**	1553.00	338.0	326	**18636.00**
3	GEN B	1443.66	150	0	**216549.00**	1498.63	150.0	150	**0.00**
4	GEN D	1449.54	0	0	**0.00**	1450.00	100.3	0	**145435.00**
6	GEN E	1440.27	0	0	**0.00**	1475.97	0.0	0	**0.00**
SUB TOTAL			**1058**	**50**	**1393692.98**		**1050.3**	**1008**	**140071.00**

		EX-ANTE				EX-POST			
		EAESP	**EAQSI**	**BCQ**	**EAETA**	**EPESP**	**AQEI**	**EAQOM**	**EPETA**
LOAD		**P/MWh**	**MW**	**MW**	**P**	**P/MWh**	**MW**	**MW**	**P**
3	LOAD 3	1443.13	300	0	**432939.00**	1457.89	300	300	**0.00**
4	LOAD 4	1443.13	150	50	**144313.00**	1457.89	150	100	**0.00**
5	LOAD 2	1443.13	200	0	**288626.00**	1457.89	200	200	**0.00**
6	LOAD 1	1443.13	350	0	**505095.50**	1457.89	350	350	**0.00**
SUB TOTAL			**1000**	**50**	**1370973.50**		**1000.00**	**950.00**	**0.00**

		EX-ANTE				EX-POST			
		EAESP	**EAQSI**	**BCQ**	**EAETA**	**EPESP**	**AQEI**	**EAQOM**	**EPETA**
DEMAND BIDS		**P/MWh**	**MW**	**MW**	**P**	**P/MWh**	**MW**	**MW**	**P**
4	D BID 1	1449.54	15.0	0.0	**21743.15**	1450.00	15.0	15.0	**0.00**
5	D BID 2	1442.53	20.0	0.0	**28850.59**	1371.08	20.0	20.0	**0.00**
SUB TOTAL			**35.00**	**0.00**	**50593.74**		**35.00**	**35.00**	**0.00**

RESERVE COST RECOVERY CHARGE								
TRADING PART.			**REG. RESERVE CHARGE**			**CONTIN. RESERVE CHARGE**		
GENERATOR		**AQEI**	**RRQ**	**RRP**	**RRC**	**CRQ**	**CRP**	**CRC**
NODE	**ID**	**MW**	**MW**	**P/MW**	**P**	**MW**	**P/MW**	**P**
1	GEN A	462	6.6	426.43	2814.44	44.0	1049.2	46152.74
2	GEN C	338	4.8	426.43	2046.86	32.2	1049.2	33767.32
3	GEN B	150	2.2	426.43	938.15	14.3	1049.2	14985.50
4	GEN D	100.3	1.4	426.43	597.00	9.5	1049.2	10018.44
6	GEN E	0	0	426.43	0.00	0.0	1049.2	0.00
SUB TOTAL		**1050.3**	**15**		**6396.45**	**100.00**		**104924.00**

			REG. RESERVE CHARGE		
LOAD		**AEQW**	**RRQ**	**RRP**	**RRC**
NODE	**ID**	**MW**	**MW**	**P/MW**	**P**
`3	LOAD 3	300	4.35	426.43	1854.04
4	LOAD 4	150	2.17	426.43	927.02
5	LOAD 2	200	2.90	426.43	1236.03
6	LOAD 1	350	5.07	426.43	2163.05
SUB TOTAL		**1000.0**	**14.5**		**6180.14**

			REG. RESERVE CHARGE		
DEMAND BIDS		**EEQW**	**RRQ**	**RRP**	**RRC**
NODE	**ID**	**MW**	**MW**	**P/MW**	**P**
4	D BID 1	15	0.22	426.43	92.70
5	D BID 2	20	0.29	426.43	123.60
SUB TOTAL		**35.0**	**0.5**		**216.31**

AGGREGATE TRADING AMOUNT FOR PARTICIPANTS

GENERATOR	GEN. A	GEN. B	GEN. C	GEN. D	GEN. E
EX-ANTE ENERGY TRADING AMOUNT	713757.80	216549.00	463386.18	0.00	0.00
EX-POST ENERGY TRADING AMOUNT	-24000.00	0.00	18636.00	145435.00	0.00
REGULATING RESERVE TRADING AMOUNTS	0.00	0.00	0.00	0.00	0.00
CONTINGENCY RESERVE TRADING AMOUNTS	0.00	0.00	0.00	0.00	0.00
TRANSMISSION RIGHT TRADING AMOUNTS	2327.44	0.00	0.00	0.00	0.00
LINE RENTAL TRADING AMOUNTS	-5074.00	0.00	0.00	0.00	0.00
REGULATING RESERVE COST RECOVERY CHARGE	7675.20	0.00	5117.16	0.00	0.00
	-2814.44	-938.15	-2046.86	-597.00	0.00
CONTINGENCY RESERVE COST RECOVERY CHARGE	0.00	0.00	52462.00	0.00	52462.00
	-46166.56	-15004.13	-33785.53	-9967.78	0.00
TOTAL	**645705.44**	**200606.72**	**503768.95**	**134870.22**	**52462.00**

LOAD	LOAD 1	LOAD 2	LOAD 3	LOAD 4
EX-ANTE ENERGY TRADING AMOUNT	505095.50	288626.00	432939.00	144313.00
EX-POST ENERGY TRADING AMOUNT	0.00	0.00	0.00	0.00
TRANSMISSION RIGHT TRADING AMOUNTS	0.00	0.00	0.00	0.00
LINE RENTAL TRADING AMOUNTS	0.00	0.00	0.00	0.00
REGULATING RESERVE COST RECOVERY CHARGE	2162.00	1236.65	1854.97	925.35
TOTAL	**507257.50**	**289862.65**	**434793.97**	**145238.35**

DEMAND BIDS	DEMAND BID 1	DEMAND BID 2
ENERGY TRADING AMOUNT FOR DEMAND BIDDER	21743.10	28850.60
REGULATING RESERVE COST RECOVERY CHARGE	93.81	123.66
TOTAL	**21836.91**	**28974.26**

Line Rental Trading Amount

$$\mathbf{LR = (P_R \times Q_R) - (P_S \times Q_R)}$$

Where:

P_R	is the ex-ante nodal price at the receiving node
P_S	is the ex-ante nodal price at sending node
Q_R	is the expected (ex-ante) quantity of flow out of the receiving node
Q_S	is the expected (ex-ante) quantity of flow into the sending node

Sample Computation

Since the bilateral amount is netted in the settlement, the unsettled line rental trading amount shall be recovered from either the generator or load depending on their agreement under the bilateral contract. For this example, Generator A shall pay for the line rental trading amount as shown in the following computation:

$$\begin{aligned} LR_{GEN\ A} &= (P_R \times Q_R) - (P_S \times Q_R) \\ &= (1443.13 \times 50) - (1341.65 \times 50) = P\ 5{,}074.00 \end{aligned}$$

Financial Transmission Right

$$\mathbf{FTR = MW \times [(P_R \times (1 - \%Loss)] - P_S)}$$

where:

MW	is the contracted transmission right capacity
P_R	is the ex-ante nodal price at the receiving node
%Loss	is the agreed loss differential for the transmission right
P_S	is the ex-ante nodal price at sending node

Sample Computation

With an FTR for 40MW capacity, Generator A will be paid the amount as shown in the computation.

$$\begin{aligned} FRT_{GEN\ A} &= MW \times [(P_R \times (1 - 0.03)) - P_S] \\ &= 40 \times ((1443.13 \times (0.97)) - 1341.65) = P\ 2{,}327.44 \end{aligned}$$

3.0 Summary of Analysis

3.1 Ex-Ante Schedule

Benefit is maximized by excluding demand bid blocks with price bids lower than the resulting marginal prices. Energy and Reserves co-optimization was achieved without any resulting line constraint. Since there was no line constraint, generators were dispatched up to their maximum quantity offers and only one resulting marginal plant is setting the nodal prices. Nodal prices were adjusted to reflect transmission losses.

3.2 Ex-Post Schedule

There is a binding constraint optimization solution caused by the capacity derating (from 350MW reduced to 250 MW) on L_{12} connecting nodes 1 and 2. Because of this constraint, generator A was constrained and generator D which has higher offer was dispatched. Generator A and Generator D are two marginal plants setting the nodal prices and since Generator D has higher offer the resulting nodal prices are higher than the ex-ante nodal prices.

3.3 Settlement

Customers will pay based on the Customer Zonal Price. Demand Bids will pay and generators will collect at nodal prices. Regulating Reserve Recovery Cost is shared by the generators and loads. Contingency Reserve Recovery Cost is allocated to all dispatched Generators. Network Service Providers will be assessed of contingency reserve recovery charges under a formula which accounts for the relative size of the relevant generating system and distribution network, their reliability, and the impact which failure may have on conditions within that reserve cost recovery zone.

The net settlement trading amount for all trading participants will either be a surplus or deficit depending on the extent of the constraint, offers, and bids parameters. In our example, prices determined during ex-ante unconstrained scenario were raised because of constrained scenario during real time dispatching. This situation has resulted in a net settlement deficit.