Deregulation and Electricity Markets

Objectives

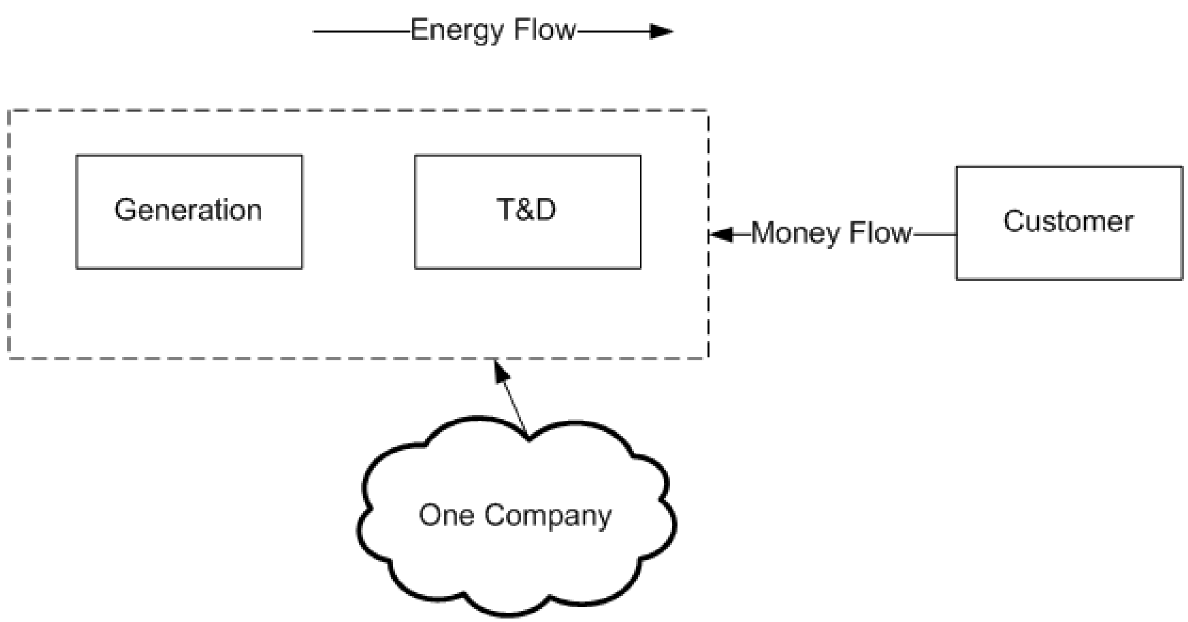
- Understand what is deregulation
- Introducing the different entities in a deregulated electricity market
- Benefits from a competitive market

What is Deregulation?

- The electric power industry has been dominated by large utilities that had full authority over all activities in generation, transmission and distribution.

- Such Utilities are know as Vertically integrated Utilities.

- In such case, it is often difficult to segregate the cots incurred in generation, transmission and distribution.



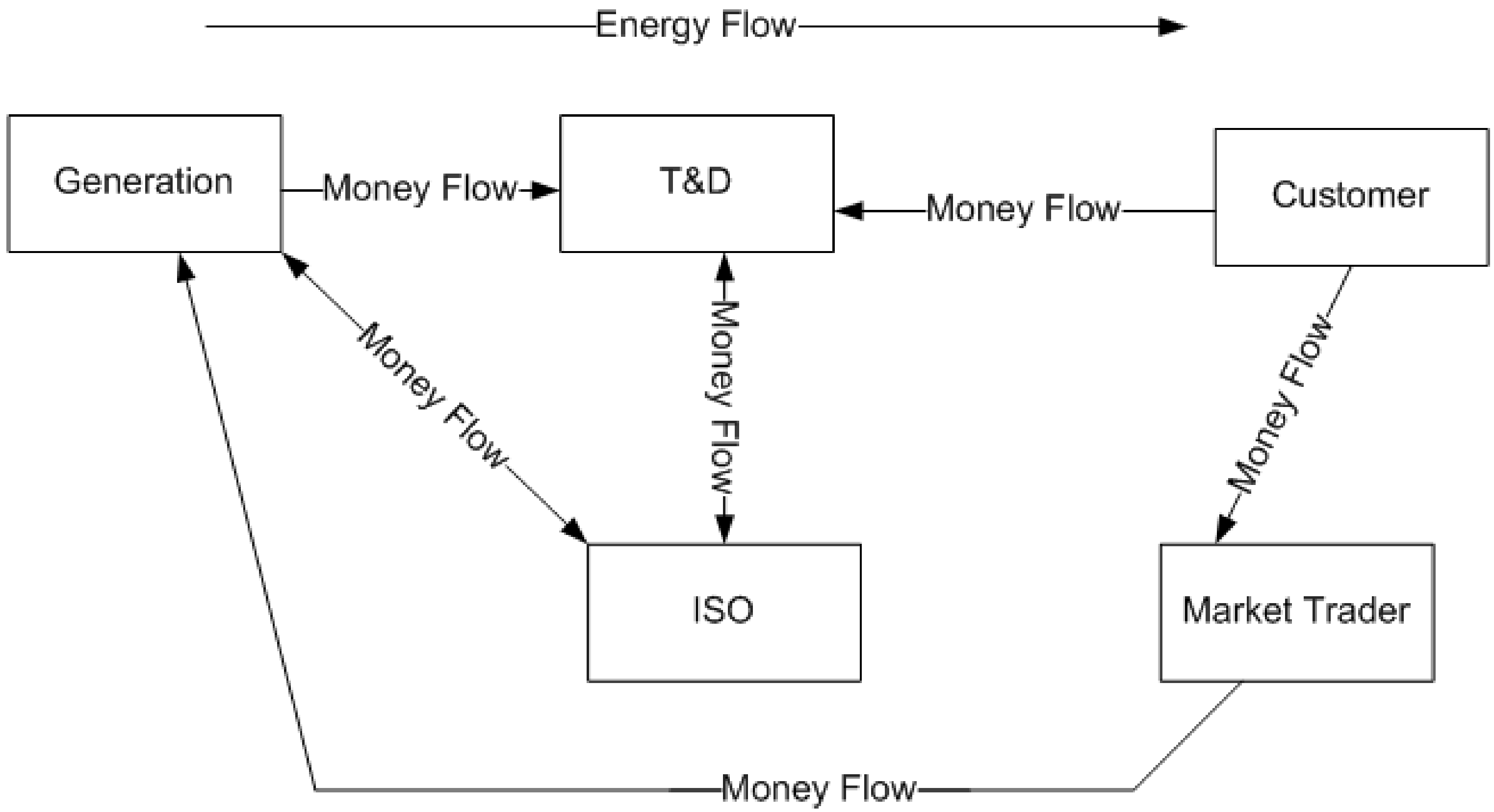
What is Deregulation?

- Steps in restructuring the power industry:

1. Separation of transmission activities from generation activities
2. Introduce competition in generation activities.

- Transmission system has a tendency to become a monopoly. Regulation was introduced to avoid it from overcharging for its services. Third parties are offered open access to the transmission network.
- A system operator is responsible for keeping the system under balance. System operator is an independent authority without any involvement in market nor can own generation.
- System operators are known as Independent System Operator (ISO).

What is Deregulation?



Different Entities Under Deregulation

1. Generator Companies (Genco)
   - Produce and sell electrify
   - Refers to one individual generator unit or a group that is owned by one person and commonly referred to as Independent Power Producer (IPP).
2. Transmission Companies (Transco)
   - Own and operate the transmission lines
   - Transfer power from Genco to Customers and make wires available to all entities.
   - For their services, they have a transmission tariff

Different Entities Under Deregulation

3. Distribution Companies (Disco)
   – Own and Operate the local distribution network.
   – Buy wholesale electricity through spot market or though direct contracts with gencos
   – Supply electricity to end user.
4. Customer
   – Consume electricity.
   – Can buy electricity directly from spot market by bidding or may buy from genco or from Local Distribution Company (LDC)

Different Entities Under Deregulation

5. Independent System Operator (ISO)
   - Ensures reliability and security
   - Does not participate in market trades.
   - Does no own generation but can have some reserve capacity.
6. Market Operator
   - Responsible for electricity market trading
   - Received bids from market participants and set the market price.

Reasons for Deregulation

- Customers were not satisfied with rising costs of electricity
- Pressure from small players in the business to reduce the control and power of large state owned large utilities by opening the market.

Benefits of a Competitive Electricity Market

- Cheaper electricity
  - Attracts new industry and business opportunities.
  - Lower cost allows customers to re-invest profits back into business
- Efficient Capacity Expansion Planning
  - Investment decisions are enhanced due to greater knowledge of demand-supply dynamics.
  - New participants are encouraged to enter thus enhancing economic development.
- Pricing is cost reflective rather than a tariff (driving participants to min. costs)
- More choice, employment and better service

Role of ISO

- Ensure system security and reliability
- Fair transmission tariffs.
- Depending on the market structure, the ISO could be placed into two categories:

1. Pool Structure where ISO is responsible for market settlement including scheduling and dispatch and transmission system management.
2. Open Access Structure dominated by bilateral contracts where ISO has no role in generation scheduling or dispatch and only responsible for system operation.

ISO in Pool Markets

- Receives Bids from suppliers
- Unit commitment and dispatch for gencos
- Setting market price
- System security
- Congestion management for which it has ancillary service
- Ancillary services are activities to support transmission of power while maintaining reliable operation.
- Ancillary services include frequency regulation, voltage and reactive power control, system stability, maintenance of generation and transmission reserves.

ISO in Pool Markets

- On a time scale, the ISO activities could be classified as follows:

1. 24 hour ahead
   - Carries out load forecast
   - Receives offers for supply of power from gencos.
   - Offers contain information on unit commitment such as start-up costs, shut down time, ramp rate limits and associated costs.
   - Formulates the nodal marginal costs and congestion prices.
2. In real time
   - Dispatches generation and load and provides system services.
3. After real time
   - Calculates settlements which include fuel costs, capacity costs, congestion surcharges, network service charges and ancillary services

ISO in Pool Markets

- Genco bid might differ based on the power pool.
- PJM (Pennsylvania, Jersey, Maryland), a unit commitment model is simulated by ISO. Thus Genco bid includes energy prices, min and max generation levels and start up costs.
- In the NYISO (New York ISO), it is assumed that genco have incorporated their unit commitment decisions while placing their bids. In this case Genco would include energy cost + ramp rate cost.

Types of Market Settlement

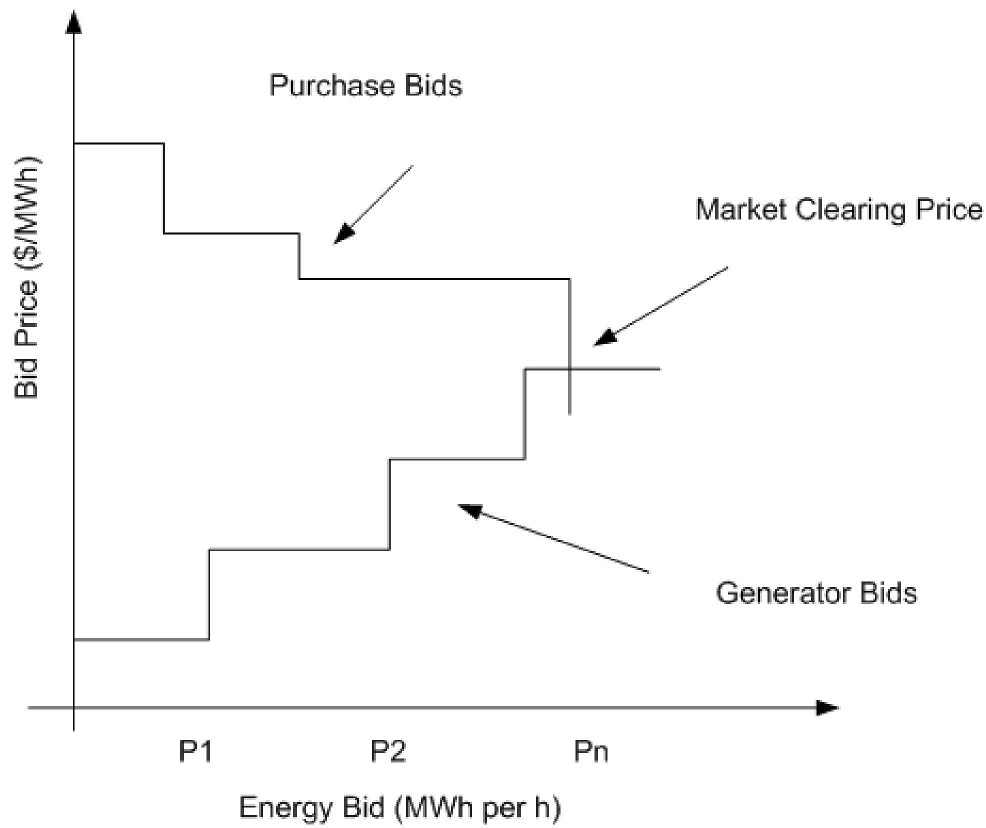
- Maximization of social Welfare
  - Effectively minimize total costs under assumption that genco offers correspond to actual costs.
- Minimization of Consumer Payment
  - Effectively minimize market clearing price and hence price customers would pay

Maximizing Social Welfare

- This is the most common approach
- Two cases arise, one where both supply and load can bid and the other where the supply is the only entity that bids.
    - Double Auction Markets where both load and supply bid
    - Single auction markets where supply only bids to meet total demand.

Double Auction Markets

- Stack the supply bids in increasing order and the demand bids in decreasing order. The intersection of both curves will result in the market clearing price.



Double Auction Markets

- Assume market operator receives N supply bids (BPS) and M demand bids (BPB). We will assume that BPS represents the genco's true marginal cost while BPB represents a customer's true benefit. Then

$$C_i = f(P_i) \quad \forall i \varepsilon N$$

$$B_j = g(PD_j) \quad \forall j \varepsilon M$$

Ci is the genco cost function and Bj is the customer benefit function. The social welfare denoted by J can be written as follows:

$$J = \sum_{j=1}^{M} PD_j \cdot BPB_j - \sum_{i=1}^{N} P_i \cdot BPS_i$$

$$J = \sum_{j=1}^{M} B_j - \sum_{i=1}^{N} C_i = \sum_{j=1}^{M} g_j(PD_j) - \sum_{i=1}^{N} f_i(P_i)$$

Double Auction Markets

- We try to maximize the social welfare subject to

$$\sum_{i=1}^{N} P_i = \sum_{j=1}^{M} PD_j$$

$F =$

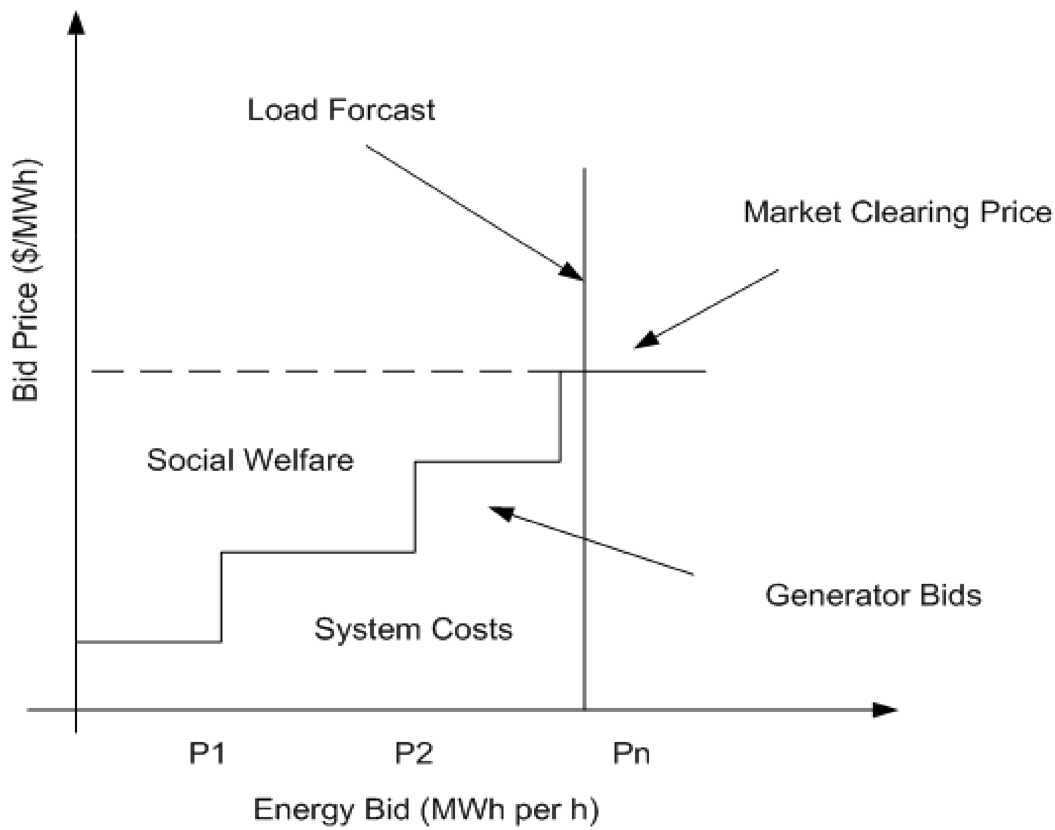
- Formulating the Lagrangian for the maximization

$$F = \sum_{j=1}^{M} g_j(PD_j) - \sum_{i=1}^{N} f_i(P_i) - \lambda\left(\sum_{j=1}^{M} PD_j - \sum_{i=1}^{N} P_i\right)$$

- Using Kuhn Tuckers condition of optimality, the optimal solution could be found. λ denotes the system marginal cost.

Single Auction Market

- The highest priced bid to intersect with the system demand forecast determines the market price.



Single Auction Market

- Maximizing social welfare in this case is equal to minimizing the genco costs

$$Min(J) = \sum_{i=1}^{N} P_i \cdot BPS_i = \sum_{i=1}^{N} f_i(P_i)$$

- This is subject to

$$\sum_{i=1}^{N} P_i = \sum_{j=1}^{M} PD_j$$

- Again, using Kuhn-Tuckers optimality conditions

$$\frac{dC_i(P_i)}{dP_i} = \lambda$$

Note: The lagrangian function would be:

$$Min(J) = \sum_{i=1}^{N} f_i(P_i) - \lambda(\sum_{i=1}^{N} P_i - PD)$$

Single Auction Market

- Other additional things to include would be the ramp rate limits. The genco could also provide a start up bid which could be added to the objective function as follows:

$$Min(J) = \sum_{k=1}^{T} \sum_{i=1}^{N} P_{i,k} \cdot BPS_{i,k} + ST_i \cdot UST_{i,k}$$

- Where k denotes the bid time period which could be half an hour and T stands for the entire scheduling horizon (i.e 48 for the above case). UST is a binary variable denoting unit start-up decision while ST is the start up cost bid.

Economic Load Dispatch

- ELD primarily involves allocating the total load between the available generating units.
- An ELD is usually executed every 5 minutes and thus it is very important that the algorithm is efficient and at the same time represents the system in as much detail as possible.
- The main objective is to minimize total system costs

$$J = \sum_{i=1}^{NT} C_i(P_i)$$

Subject To

$$\sum_{i=1}^{NT} P_i - PD - P_{Loss} = 0 \qquad \text{and} \qquad P_{Loss} = f(P)$$

$$P_i^{\min} \leq P_i \leq P_i^{Max} \qquad \forall\, i = 1,\ldots\ldots\ldots\ldots, NT$$

ELD

- Lagrangian

$$F(P,\lambda,\mu,\gamma) = \sum_{i=1}^{NT} C_i(P_i) - \lambda(\sum_{i=1}^{NT} P_i - PD - P_{Loss})$$

$$-\mu_1(-P_1 + P_1^{Min}) - \mu_2(-P_2 + P_2^{Min}) - ......- \mu_{NT}(-P_{NT} + P_{NT}^{Min})$$

$$-\gamma_1(P_1 - P_1^{Max}) - \gamma_2(P_2 - P_2^{Max}) - ......- \gamma_1(P_{NT} - P_{NT}^{Max})$$

- Applying Kuhn Tucker's Condition of Optimality

$$\frac{\partial F}{\partial P_i} = 0, \quad \frac{\partial F}{\partial \mu} = 0$$

$$\frac{\partial F}{\partial \lambda} = 0, \quad \frac{\partial F}{\partial \gamma} = 0$$

- Then

$$\frac{\partial C_i}{\partial P_i} - \lambda(1 - \frac{\partial P_{Loss}}{\partial P_i}) = 0$$

ELD

- λ denotes the change in system cost and is known as the system incremental cost.

$$\frac{\partial C_i}{\partial P_i} / (1 - \frac{\partial P_{Loss}}{\partial P_i}) = \lambda$$

$$1 / (1 - \frac{\partial P_{Loss}}{\partial P_i}) = penalty\ \ factor$$

ELD

- Example:

$$\min[(1P_1^2 + 8.5P_1 + 5) + (3.4P_2^2 + 25.5P_2 + 9)]$$

$$s.t$$

$$P_1 + P_2 = P_D = 700$$

$$Applying\ K.T$$

$$2P_1 - \lambda = -8.5$$

$$6.8P_1 - \lambda = -25.5$$

$$P_1 + P_2 = 700$$

$$Thus,$$

$$P_1 = 542.841, P_2 = 157.159, \lambda = 1094.182$$

ELD

- Refer to ELD GAMS file to see what happens when you add limits to units

1. Increase in system cost.
2. λ has increased
3. The dual variable on the generation that reaches the limit is -377$/MWh which indicates that if the limit is relaxed by 1 MW, the system cost will reduce by $377

Unit Commitment

- Long term scheduling usually covering a time range from 24 hours ahead to a week ahead.
- The load forecast is used in the program.
- Similar to ELD, system operator seeks to minimize costs over a planning horizon and thus arrive at optimal unit up/down status for every hour.
- UC are mush more complex to solve due to the binary decsions

Unit Commitment

- Objective

$$J = \sum_{k=i}^{T} [C_{i,k}(P_{i,k}) \cdot W_{i,k} + ST_{i,k} U_{i,k} + SD_{i,k} \cdot V_{i,k}]$$

- where

$$W = \begin{Bmatrix} 0 & \textit{Unit is off} \\ 1 & \textit{Unit is on} \end{Bmatrix}; \quad U = \begin{Bmatrix} 0 & \textit{No start up} \\ 1 & \textit{Start up} \end{Bmatrix}; \quad V = \begin{Bmatrix} 0 & \textit{No shut down} \\ 1 & \textit{Shut down} \end{Bmatrix}$$

$$ST_i = \alpha_i + \beta_i (1 - e^{-Toff_i / \tau_i})$$

α is fixed cost associated with start up, β is the cost involved in cold start up, τ is cooling system time constant, Toff is the time for which the unit was off. ST is start up cost and SD is shutdown cost which is small and usually not considered in analysis.

Unit Commitment

- Demand-Supply Balance and Spinning Reserve

$$\sum_{i=1}^{NG} P_{i,k} \cdot W_{i,k} + (I_k - E_k) \geq PD_k + RES_k$$

Where RES is the spinning reserve, I is the amount of power imported and E is the amount of power exported, PD is the power demand.

- Minimum Up and down Time (Usually applicable to large thermal units)

$$\sum_{n=1}^{MUT} V_{th,k-n+1} \leq 1; \quad \forall k \geq MUT$$

$$\sum_{m=1}^{MDT} U_{th,k-m+1} \leq 1; \quad \forall k \geq MDT$$

Unit Commitment

- Generation Limit

$$P_i^{Min} \le P_{i,k} \cdot W_{i,k} \le P_i^{Max}$$

- Must Running Unit

$$W_{i,k} = 1$$

- Ramp rate Constraints on thermal units

$$P_{i,k} - P_{i,k-1} \le RUP_i$$
$$P_{i,k-1} - P_{i,k} \le RDN_i$$

Optimal Power Flow (OPF)

- The optimal power flow is a more accurate estimate than ELD solution. The OPF is solved to minimize total power generation cost but could also be formulated to minimize transmission loss.

$$J = \sum_{i=1}^{NG} C_i(P_i) \qquad \text{where} \quad C(P_i) = aP_i^2 + bP_i + c$$

Power Flow Equations

$$P_i - PD_i = \sum_j |V_i||V_j| Y_{i,j} \cos(\theta_{i,j} + \delta_j - \delta_i) \quad Q_i - QD_i = -\sum_j |V_i||V_j| Y_{i,j} \sin(\theta_{i,j} + \delta_j - \delta_i)$$

Generator Limits

$$P_i^{Min} \le P_i \le P_i^{Max} \qquad Q_i^{Min} \le Q_i \le Q_i^{Max}$$

Voltage Limits

$$V_i^{Min} \le V_i \le V_i^{Max} \quad \forall\, i \in 1,\ldots..NL \qquad |V_i| = \text{constant} \ \ \forall\, i \in 1,\ldots\ldots..NG$$

OPF

- Limits on Power flow

  $$P_{i,j} \le P_{i,j}^{Max}$$

- With the OPF solution, it is possible to develop pricing mechanisms for real and reactive power delivered at a bus in the system.
- The real power price based on marginal cost at a bus can be given as

$$\rho_{Pi} = MC_{Pi} - \lambda_i^{Min} + \lambda_i^{Max}$$

- Where λ represents the dual associated with the lower and upper generation limit. MC is the marginal cost of real power at a bus

Impact of Intentional Islanding of Distributed Generation on Electricity Market Prices

Outline

- Introduction
- Scope of Work
- DG Islanding
- Problem Formulation
  - Market Simulation Model in Normal Operation
  - Market Simulated Model in Islanded Operation
- Scenarios
  - Scenario 1: NORMAL OPERATION
  - Scenario 2: CURRENT PRACTICE FOLLOWING DISTURBANCES
  - Scenario 3: INTENTIONAL ISLANDING WITH DEFICIT CAPACITY IN ISLANDED SYSTEM
  - Scenario 4: INTENTIONAL ISLANDING WITH SURPLUS CAPACITY IN ISLANDED SYSTEM
- Simulation Results
- Conclusion

Introduction

- In the competitive electricity market environment, power utilities are now realizing that customer preferences and their purchase decisions are greatly affected by the power supply reliability.
- Main challenges
  - To provide enhanced levels of services to the customers while maintaining acceptable reliability standards.
  - Lower the cost of operation and maintenance in order to provide lower rates to customers

Introduction *Cont.*

- It is envisaged that within the coming decade, there will be significant changes in distribution system configuration and this will include a large growth in DGs capacity.
- A study by Electric Power Research Institute (EPRI) indicates that by the year 2010, DGs will account for up to 25% of all new generation capacity in the US

Introduction *Cont.*

- The current practice in distribution system protection is either to disconnect all DGs once a fault occurs.
- However, with increasing competition to secure more customers, the energy supply companies are now increasingly under pressure to maintain a high degree of un-interrupted power supply quality and reliability.

Introduction *Cont.*

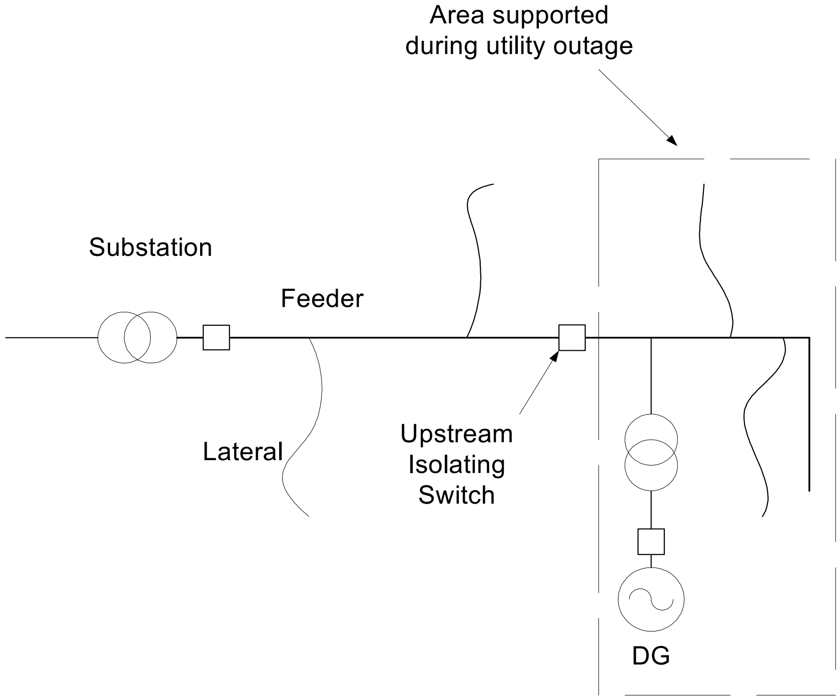
- Operation of safe intentional islands would be a viable solution.
- Certain rules should be set by the system operator in order to produce a safe island and prevent market price spikes in case of intentional islanding.

Scope of Work

- This work examines the effect of implementing safe intentional islanding of DGs and how such islanding action affects the close-to-real-time electricity market prices.
- The market clearing price is determined by formulating an optimal power flow problem but with the addition of a new constraint responsible for simulating the effect of intentional islanding.
- The effect of the cost of unserved energy on market clearing prices within the island is also examined

DG Islanding

- Islanding is a condition in which a portion of the electric utility system that contains both load and DG resources remains energized while isolated from the remainder of the utility system.



DG Islanding *Cont.*

- IEEE Std. 929-2000 necessitates the prevention of islanding.
- The IEEE Std. 1547-2003 standard addresses the topic of intentional islanding and proposes to consider this topic in its future revisions

Problem Formulation

- In this work we consider a single-auction market.
- The single-auction market settlement model is formulated in an optimal power flow framework.
- Two models are used:
    1. Market Simulation Model in Normal Operation
    2. Market Simulation Model in Islanded Operation

Market Simulation Model in Normal Mode

- The standard objective for the market operation in a single auction market is maximization of a social welfare (minimization of generation costs)

$$J = \sum_{i=1}^{NG} C_i(P_i)$$

where $C(P_i) = aP_i^{\,2} + bP_i + c$

Market Simulation Model in Normal Mode *Cont.*

Power Flow Equations

$$Q_i - QD_i = -\sum_j |V_i||V_j|Y_{i,j} \sin(\theta_{i,j} + \delta_j - \delta_i)$$

$$P_i - PD_i = \sum_j |V_i||V_j|Y_{i,j} \cos(\theta_{i,j} + \delta_j - \delta_i)$$

Generator Limits

$$Q_i^{Min} \leq Q_i \leq Q_i^{Max}$$

$$P_i^{Min} \leq P_i \leq P_i^{Max}$$

Market Simulation Model in Normal Mode *Cont.*

Voltage Limits

$$V_i^{Min} \le V_i \le V_i^{Max} \quad \forall\, i \in 1,.....NL$$

$$|V_i| = \text{constant} \quad \forall\, i \in 1,........NG$$

Uniform Market Price Formulation

$$\rho \ge \lambda_i \qquad \forall \;\; \text{i} \in 1,....\text{N}$$

where ρ represents the electricity market price, λ is the incremental cost at a bus and N is the number of buses in the system.

Market Simulation Model in Islanded Mode

- When an intentional island is formed, the system is split into two separate price areas. In cases, where there is a possibility of excess load on the islanded part, the cost of unserved energy is taken into consideration in the mathematical model for market settlement. The objective can be written as folows

$$J = \sum_{i=1}^{NG} C_i(P_i) + \sum_{i=1}^{N} C_{un}.P_{un}(i)$$

Market Simulation Model in Islanded Mode *Cont.*

Intentional Islanding Constraint

$$P_{i,j} = 0 \quad \forall\, i, j \textit{ specified} \quad \textit{buses}$$

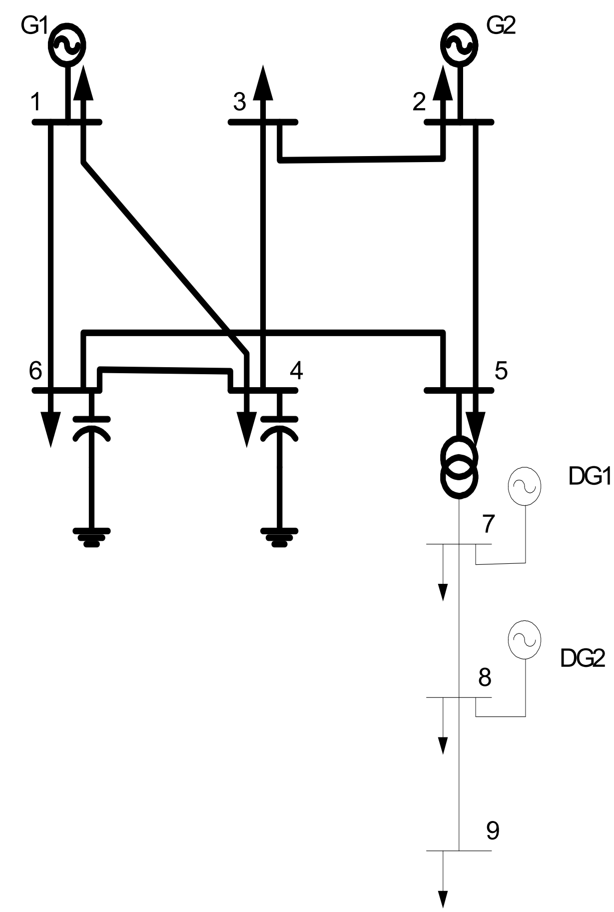
Uniform Market Price Operation

$$\rho_{ISLAND} \geq \lambda_{ISLAND,i} \qquad \forall \quad \mathrm{i} \in \mathrm{NI}$$

$$\rho_{MAIN} \geq \lambda_{MAIN,i} \qquad \forall \quad \mathrm{i} \in \mathrm{NM}$$

Scenarios *Cont.*

- The system under study consists of a 6-bus transmission system with two generating units G_1 and G_2 with capacity of 500 MVA and, 250 MVA respectively.



Scenarios *Cont.*

Scenario 1: NORMAL OPERATION

- This scenario is the base case where the system is operating normally
- In order to take into account the variations in power of the loads, a load scaling factor was used.
- No disturbances were considered

Scenarios *Cont.*

Scenario 2: CURRENT PRACTICE FOLLOWING DISTURBANCES

- A fault occurs between bus-5 and bus-7 in the system, which leads to a complete blackout of the distribution system.
- At the instant the fault occurs, all DGs were disconnected, as per the current practice.

Scenarios *Cont.*

Scenario 3: INTENTIONAL ISLANDING WITH DEFICIT CAPACITY IN ISLANDED SYSTEM

- A fault occurs between bus-5 and bus-7, thereby splitting the system into two separate parts.
- DG is intentionally islanded in order to provide power to customers in the islanded region.
- The total demand in the islanded system is greater than the DG capacity available in the island

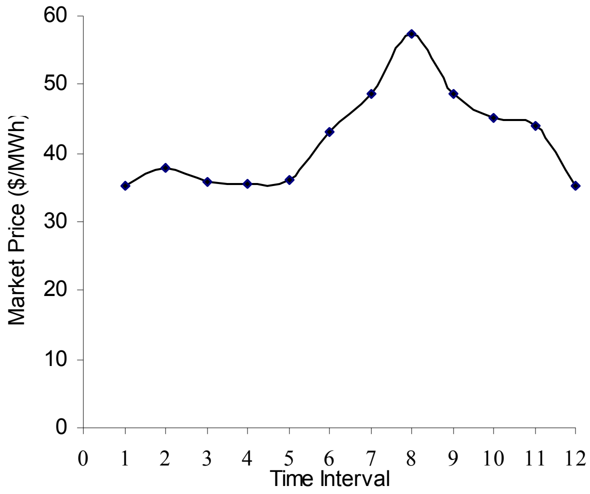
Scenarios *Cont.*

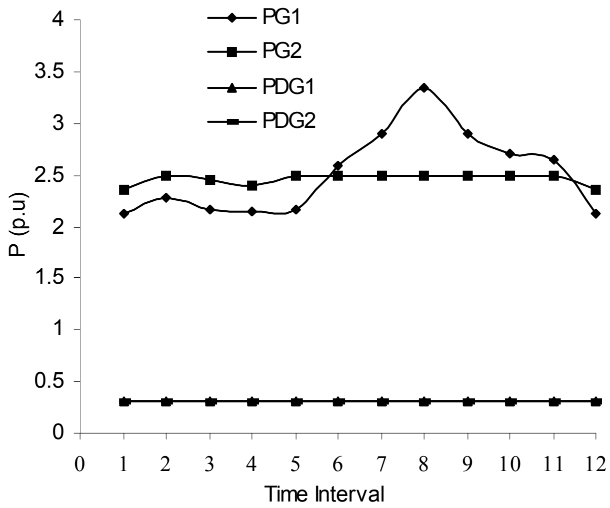
Scenario 4: INTENTIONAL ISLANDING WITH SURPLUS CAPACITY IN ISLANDED SYSTEM

- This scenario is similar to Scenario 3 except that the total DG capacities in the distribution system is greater than the demand.
- Load curtailment is not required since there is no unserved energy in the islanded system after the fault occurrence, and the island demand is fully supplied by the DGs

Simulation Results

- *Scenario 1: NORMAL OPERATION*



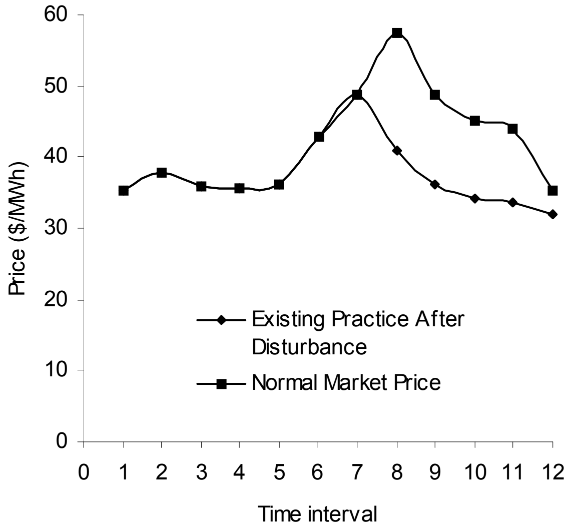


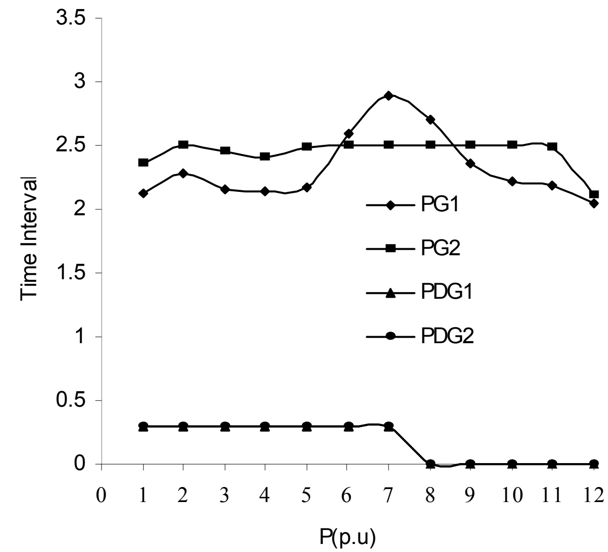
Simulation Results

Scenario 2: CURRENT PRACTICE FOLLOWING DISTURBANCES

- In this case, at interval 8 the distribution system and its DGs were disconnected after a fault.
- Each DG is rated at 30 MW

Simulation Results





Although this could lead to customers on the transmission side being satisfied as a result of the decrease in market prices during the interruption period, the distribution company could be paying its customers the cost of the unserved power during this interruption period, which can be very high.

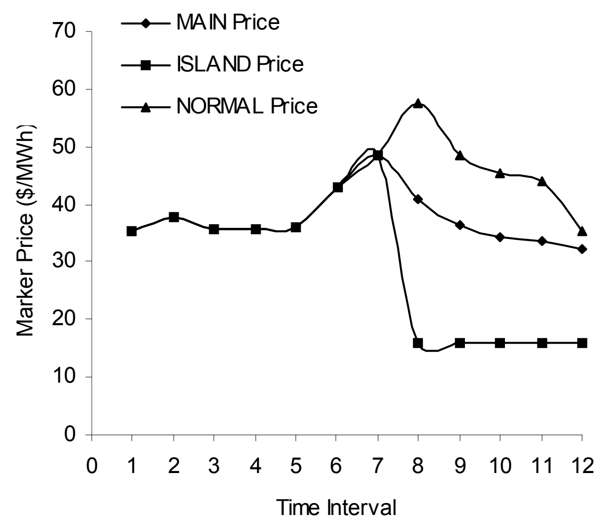
Simulation Results

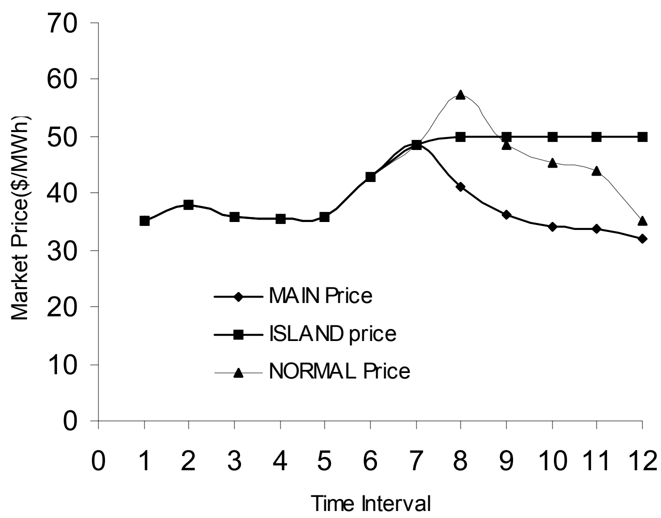
Scenario 3: INTENTIONAL ISLANDING WITH DEFICIT CAPACITY IN ISLANDED SYSTEM

- The system is split into two areas, one comprising the main transmission system and generators G_1 and G_2 while the second area comprises the distribution system with the DG_1 and DG_2
- A disturbance has occurred at time interval-8 and the distribution system is isolated from rest of the system due to a fault, but it continues to supply its customers in islanded condition from the DGs

Simulation Results

Scenario 3 market prices





Cost of Unserved Energy = 16 $/MWh

Cost of Unserved Energy = 50 $/MWh

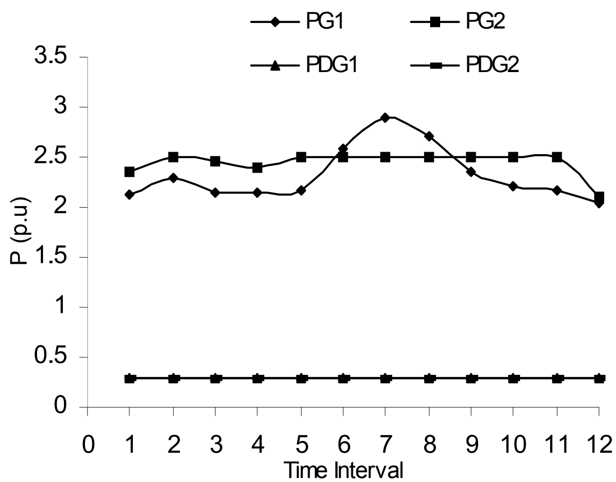
Simulation Results

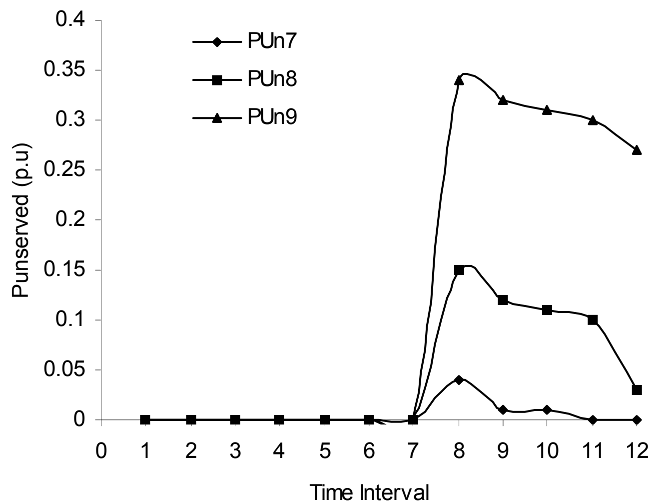
- The MAIN system price is reduced significantly after interval-8, when the islanding is in effect, as compared to the normal market operation price
- The MAIN system price is unaffected by the state of the distribution system after a disturbance, i.e. whether the distribution system is disconnected with DGs shut down, or is operating in island mode with DGs supplying power.

Simulation Results

- The ISLAND price is equal to the cost of unserved energy, once the DGs are operating at their full capacities and there is still energy unserved in the island.
- The MAIN system price is also unaffected by the cost of unserved energy, as observed in the two cases considering cost of unserved energy to be 16$/MWh and $50/MWh, respectively.

Simulation Results





Power generation of each generator

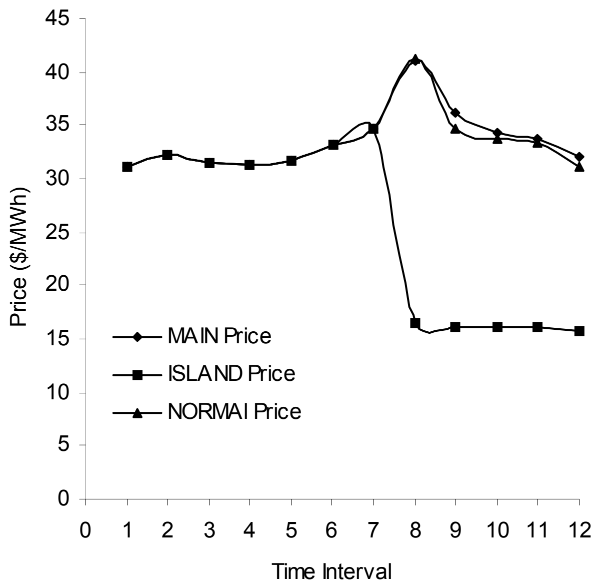
The unserved power on each bus on the distribution system

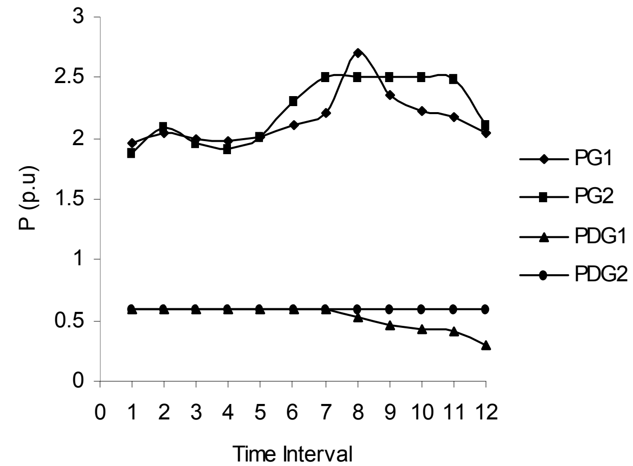
Simulation Results

Scenario 4: INTENTIONAL ISLANDING WITH SURPLUS CAPACITY IN ISLANDED SYSTEM

- This case is similar to Scenario-3 but now we consider the DGs having higher capacities, i.e. each of 60 MW
- If an outage of the transformer between bus-5 and bus-7 occurs, the DGs will be capable of supplying the entire distribution system demand when in islanded operating state, and thereby preventing any load curtailment

Simulation Results





Conclusions

- The work attempts to analyze and examine the effect of implementing intentional islands on electricity market prices
- During islanding, the system is split and each island will have its own market price
- The challenge in intentional islanding management is to set rules that will assure the secure and reliable operation of the power system in both short term and long term while maximizing market efficiency.

Conclusions *Cont.*

- These rules must be robust enough so as to prevent aggressive entities seeking advantage of islanding situation to create market power and enlarge their profits.

References

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