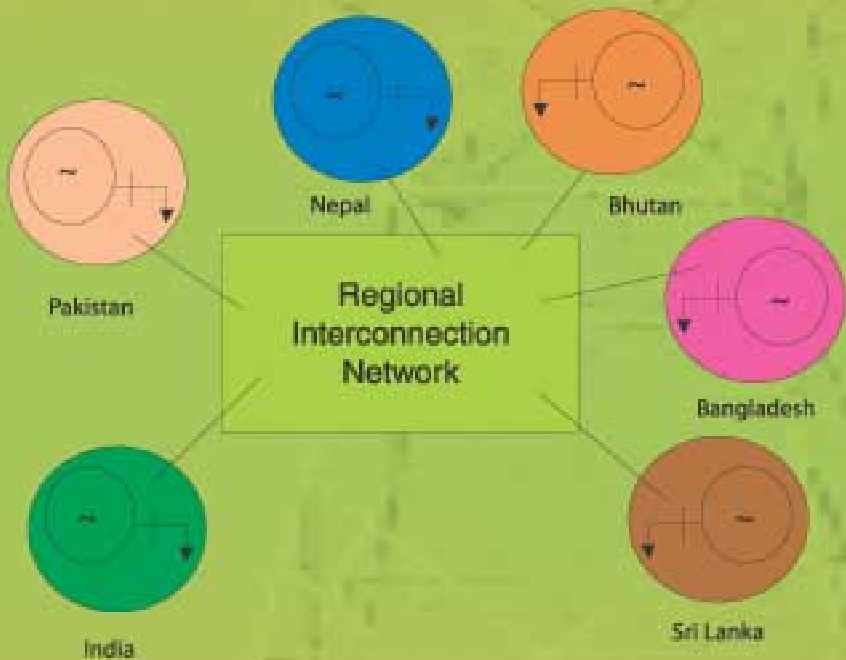
Short Term Training
on
Reliability and Operational Aspects of a Regional Grid

BUET, Dhaka, July 15-17, 2004



Sponsored by USAID and Winrock International

Organized by

Department of Electrical and Electronic Engineering
Bangladesh University of Engineering and Technology
Dhaka 1000, Bangladesh

Short Term Training on Reliability and Operational Aspects of a Regional Grid, July 15-17, 2004

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Council Building (1st Floor), BUET, Dhaka, July 15-17, 2004

Organized by EEE Dept., BUET **Sponsored by USAID and Winrock International**

July 15, 2004 Thursday

INAUGURAL SESSION

08:30 Registration of Participants
09:00 Arrival of Chief Guest
09:05 Recitation from the Holy Quran
09:10 Welcome address and course overview
09:15 Introduction by participants and expectations in the training
09:30 Address by the Head, EEE Department, BUET
09:40 Address by local representative of USAID
09:50 Address by Chief Guest
10:00 Vote of Thanks
10:05 Refreshment

LECTURE SESSION

11:00 Overview of power system operation
11:45 Role of reliability concept in a power system
12:30 Decision variables for the optimal reliability level of a utility
13:15 Lunch
14:15 Devices for controlling power system operation
15:00 Role of SCADA in power system operation
15:45 Tea
16:00 Load carrying capability of newly added generating unit/units :Reliability aspects
16:45 Evaluation techniques of reliability level of a single area utility

July 16, 2004 Friday

08:30 Unit commitment procedure in meeting the demand economically
09:15 Optimal dispatch of generating units
10:00 TR_1
11:00 Tea
11:30 Evaluation techniques of reliability level of interconnected utilities

12:15 Lunch & Prayer
14:00 Interfacing of functions related to economic operation of interconnected power systems
14:45 Concept and assessment of system security
15:30 Tea
15:45 TO_1
19:45 Dinner

July 17, 2004 Saturday

08:30 Capacity savings through interconnection and optimal tie line capacities
09:15 Multi area evaluation approach in a single area system with limited transmission capabilities
10:00 Secure operation of interconnected utilities
10:45 Tea
11:15 System reliability level: Impacts of load management schemes and joint ownership of generation
12:00 Discussion on “Regional grid: prospects, constraints and potential steps towards its achievement”
12:30 Lunch
13:30 TR_2
14:15 TO_2
15:00 Training Evaluation
15:15 Certificate Awarding
15:30 Tea
15:45 Special session for potential trainers selected from the participants (for others Site Visit)

TR = Tutorial on Reliability
TO =Tutorial on Operation

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

Overview of Power System Operation

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Reliability and Operational Aspects of a Regional Grid, July 15-17, 2004, Dhaka

- <u>Telephone vs. Power</u>

* Dial-Busy tone- “Wait and Call back later” is the normal reaction from customers

* Switch on electrical appliance-No power (“Busy” e.g. fault)- “why not power now” is the reaction from customers

- Targets of power system operation

1. Demand (MW) satisfied economically
2. Voltage maintained
3. Frequency maintained

- How to achieve?

- “MW” can be generated at power stations and despatched/exported to a far point.
- Nominal frequency can be maintained if MW generation is matched with MW demand.
- Voltage maintenance requires local injection of positive/negative “MVAR” . Because MVAR lacks mobility i.e. can not be despatched/transmitted as good as “MW”.

- Daily operation cycle (00-24 hrs)

*Forecast demand (-24 hrs)

*Choose units (-24 hrs)

*bring them on-line (00-24 hrs)

*Allocate load / review allocation (every 5 minutes)

*Send signals to generation units (instantly)

- What happens if

- a unit is lost?
- a transmission line is lost?
- the interconnector goes into outage?
- Contracted import is not firm/can not be exceeded but local demand escalates?

- Entails the following depending upon severity of the outage and its effects

-load shed

-brownout

-blackout

- What is the redress?

-Operational planning

- What is that?

-Differs from design/pre-implementation stage planning done years (i.e.3-30x10^7 seconds) ahead

- When to do it?

-in real-time (i.e. 10^0 to around 4x10^3 seconds ahead)

- Theme of operational planning:

-Monitor

-Manipulate

-Maintain

- “Manipulation” requires:

-Decision support analyses

-Convey decisions (sending commands through SCADA)

-Devices for execution (SCADA interfaced with those devices)

- The whole thing of operational planning is automated in what is known as “EMS” i.e. Energy Management System.
- Development of EMS application functions require an effort of 20 man-years.

Bibliography

The lectures on ‘operational aspects of a regional grid’ delivered in this short-term training will help one navigate the too vast and diverse literature on power system operation objectively. Some of the titles suggested for further reading are as follows.

1. A.J. Wood and B. F. Wollenberg : “Power Generation, Operation and Control”, John Wiley & Sons, USA, 1996.

2. Hadi Saadat: “Power System Analysis”, McGraw Hill, Singapore, 1999.

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5. N.G.Hingorani, “Flexible ac transmission”, IEEE Spectrum, April 1993, pp.40-45.

6. S. Shahnawaz Ahmed, S.Bashar, A.K.Chatterjee, M.A.Salam and H.B.Ahmad, “Use of superconducting magnetic storage device in a power system to permit delayed tripping”, IEE (UK) Proceedings-Genr. Transm. Distrib., Vol.147, No.5, September 2000, pp.269-273.

7. S. Shahnawaz Ahmed, Mahes Rajaratnam, Hussein Ahmad and Abu Bakar Sidik : "Potential Benefits of Using Distributed Parameter Model for Transmission Lines in Power System Analysis", IEEE (USA) Power Engineering Review, Vol. 22, No.10, October 2002, pp.53-56.

8. S. Shahnawaz Ahmed, Narayan Chandra Sarker, Azhar b. Khairuddin, Mohd Ruddin b. Abd Ghani and Hussein Ahmad: "A Scheme for Controlled Islanding to Prevent Subsequent Blackout", IEEE (USA) Transactions on Power Systems, Vol.18, No.1, February 2003, pp.136-143.

9. Azhar B. Khairuddin, S. Shahnawaz Ahmed, Wazir b. Mustafa, Abdullah Asuhaimi b. Mohd Zin, and Hussein Ahmad: "A Novel Method for ATC Computations in a Large-Scale Power System", IEEE (USA) Transactions on Power Systems, Vol.19, No.2, May 2004, pp. 1150- 1158.

10. Md. Abdus Salam and S. Shahnawaz Ahmed: "A New Method for Screening the Contingencies before Dynamic Security Assessment of a Multimachine Power System", accepted for publication in European Transactions on Electric Power (Germany) and to appear in its early 2005 issue

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

Devices for Controlling Power System Operation

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SARI ENERGY

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- What are the operands?

-Frequency

-Voltage

-Real and Reactive Power

- Device for frequency control: generator governor

-Desired frequency

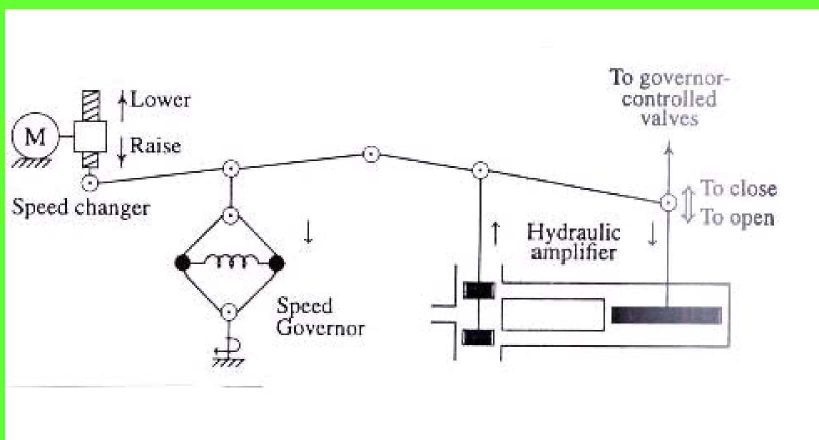
-Sensed frequency

-Control signal

-Amplify

-Valve control

Fig. A typical governor

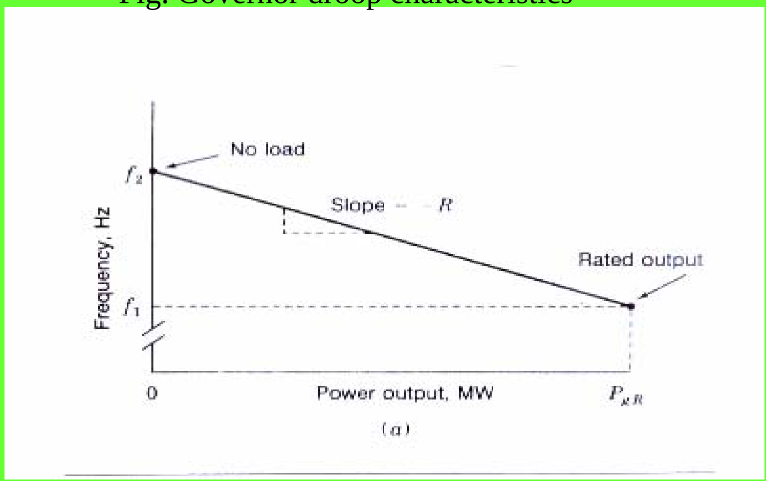


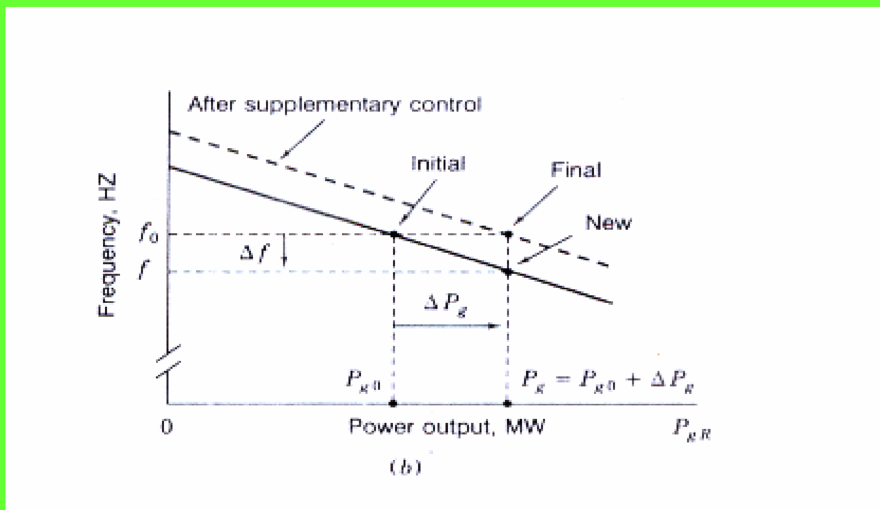
- Speed changer

-Provides set point

-Shifts droop characteristics upward or downward to schedule any output level from the generator at nominal frequency i.e. supplements governor action by letting in more or less energy from prime-mover

Fig. Governor droop characteristics





- It is the speed changer servomotor that can be operated either locally or by sending "raise" or "lower" pulses through SCADA.
- AGC (Automatic Generation Control)

-single area or isolated system

-interconnected system

Fig. AGC for a single area or isolated power system

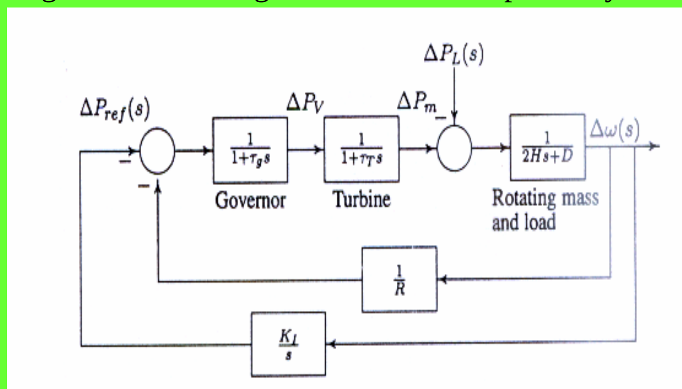
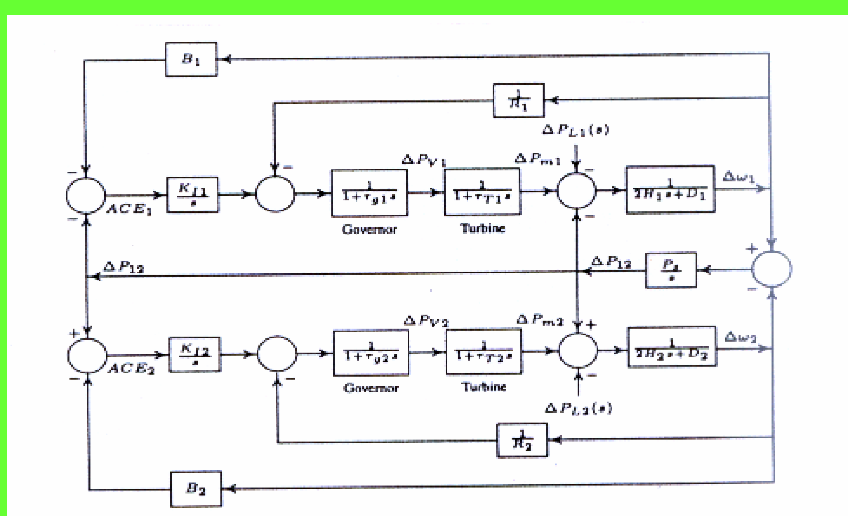


Fig. AGC for two interconnected power systems



- Devices for voltage control:

- AVR for control from generator side

- VAR compensation devices for control from buses

Fig.LFC and AVR for a genertor

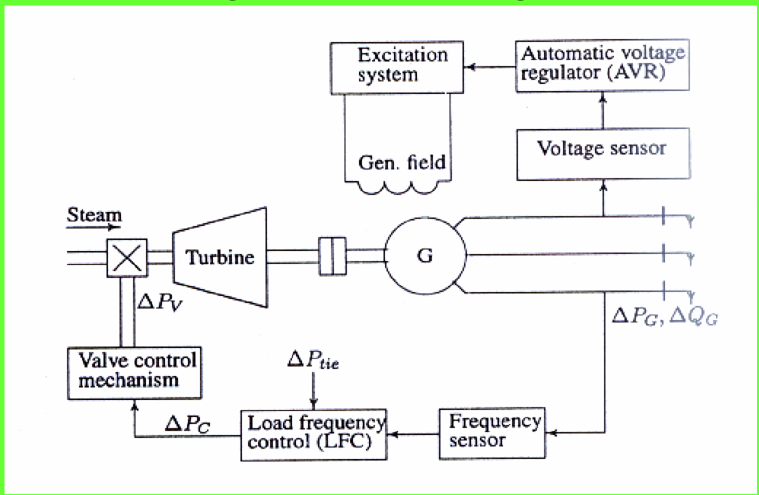
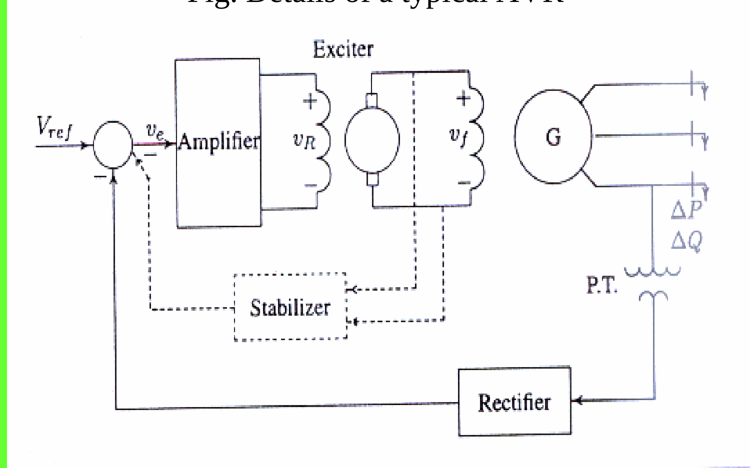


Fig. Details of a typical AVR



- LFC and AVR dynamics are weakly coupled as excitation system time constant is much smaller than prime-mover time constant.
- Voltage and frequency can be controlled almost independently.

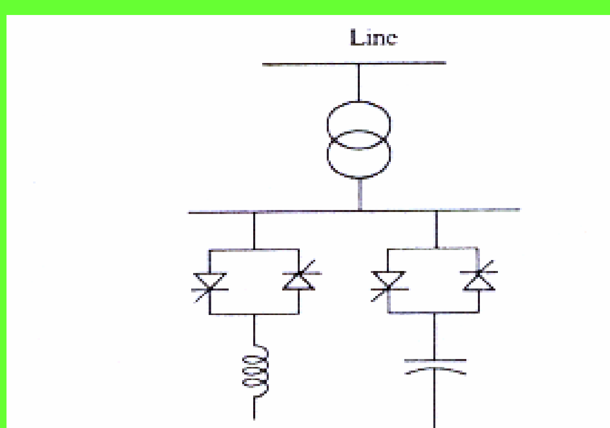
- VAR compensation devices for voltage control from buses :

-synchronous condensers

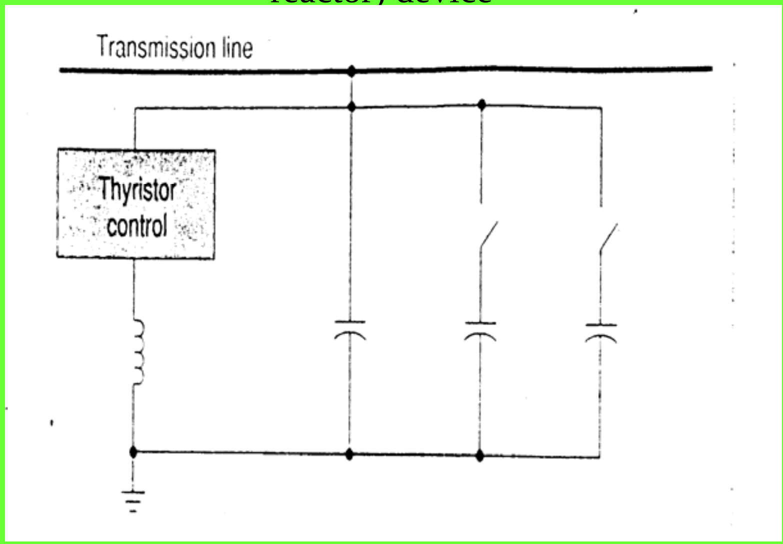
-SVC (e.g. STATCON, FC-TCR, TSC) under FACTS family

-TCUL and magnitude regulating (in-phase booster) transformers

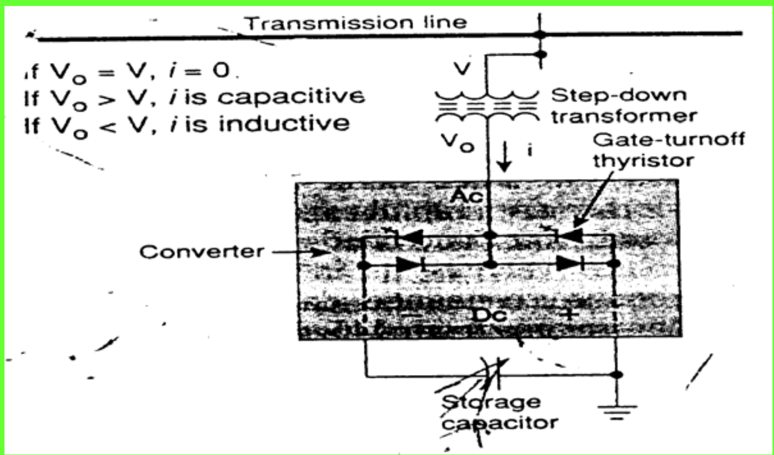
Fig.An SVC device comprising TCR and TSC/TCS



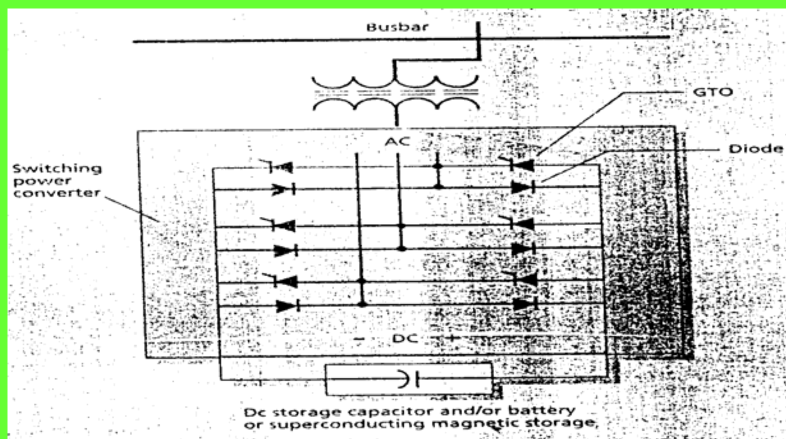
A FC-TCR (fixed capacitor-thyristor controlled reactor) device



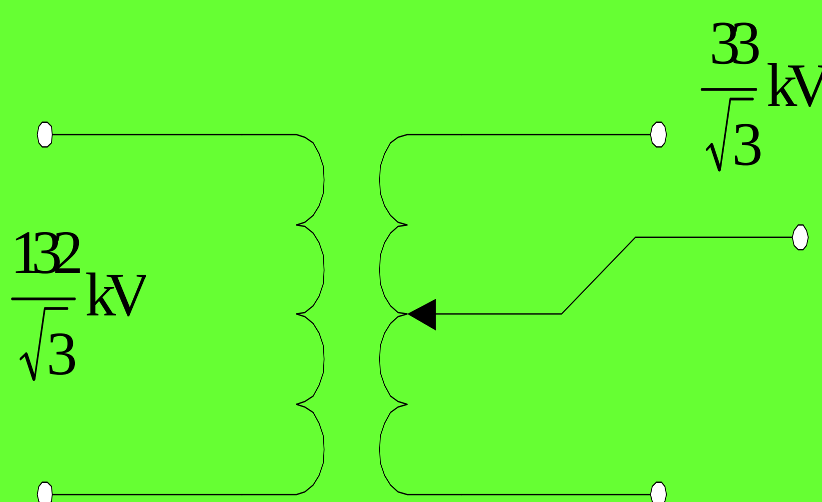
A static condenser (STATCON)



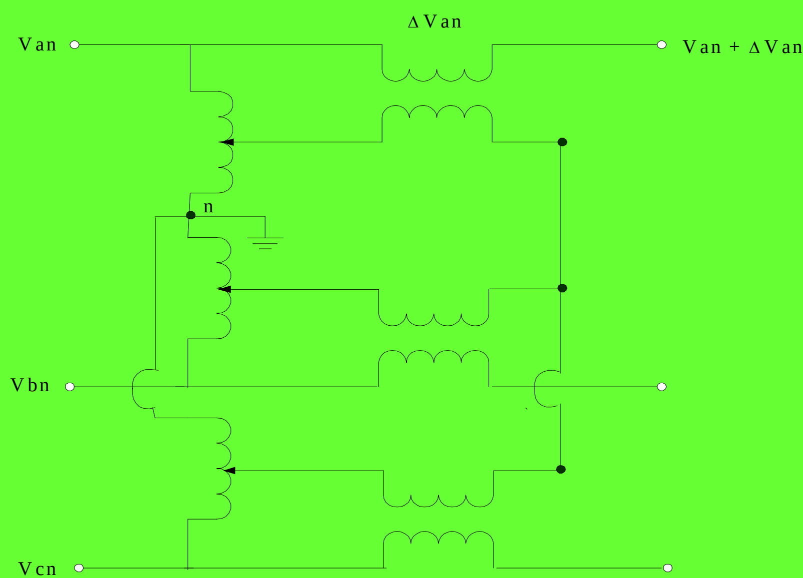
STATCON with all 3 phases shown



A TCUL transformer



An in-phase booster transformer

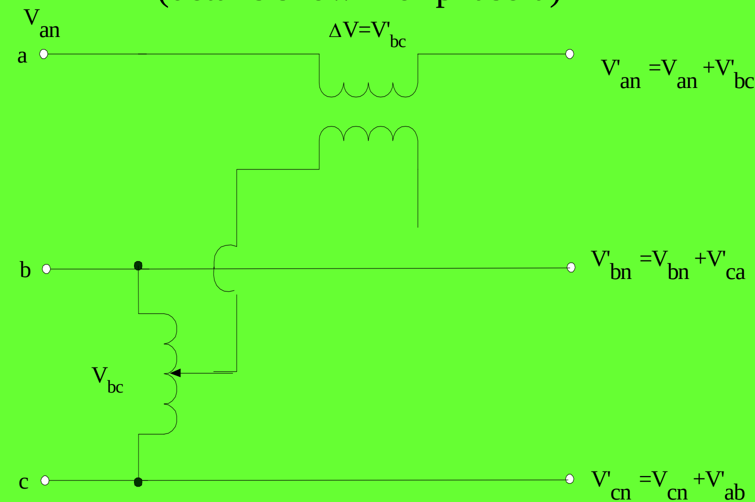


- Real power (MW) control devices:

-control of injections from generator using governor

-control of flows in lines using (i) phase shifting (quadrature booster) transformer or (ii) FACTS devices (e.g.TCSC,TCPA,UPFC)

A phase shifting transformer
(details shown for phase-a)



The underlying phasor diagram for the phase shifting transformer

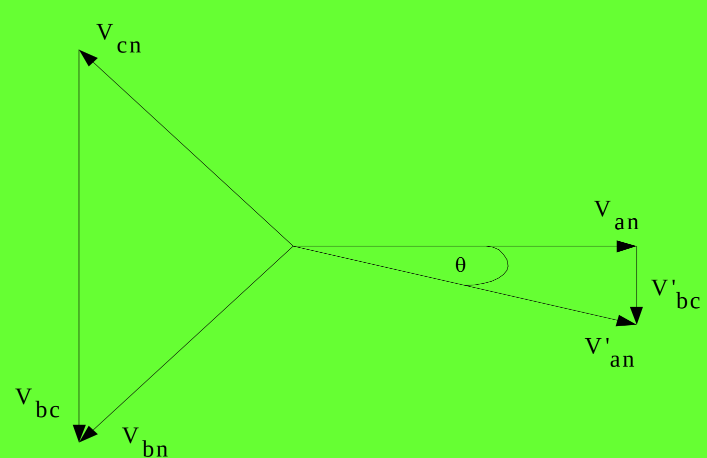
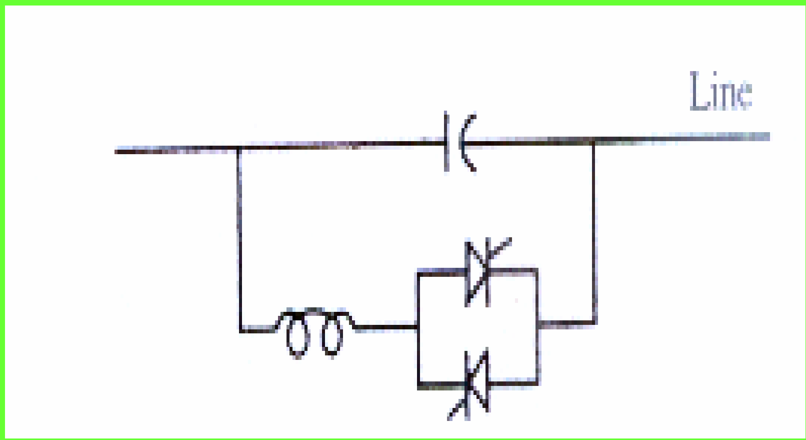
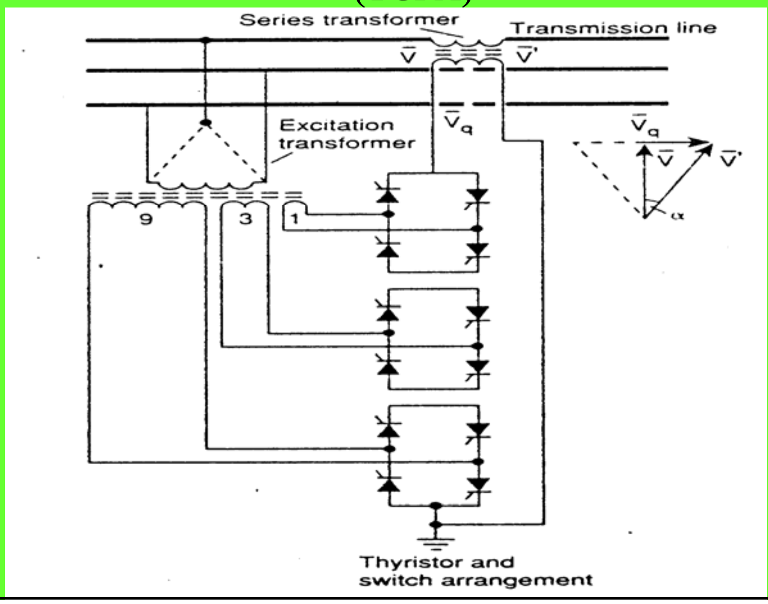


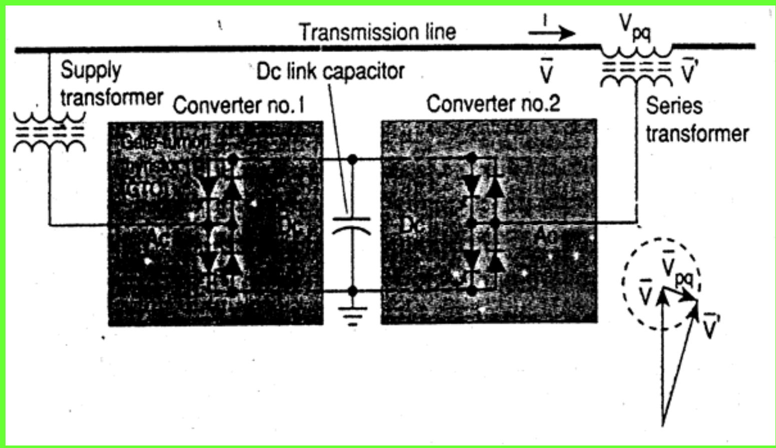
Fig. A thyristor controlled series capacitor (TCSC)



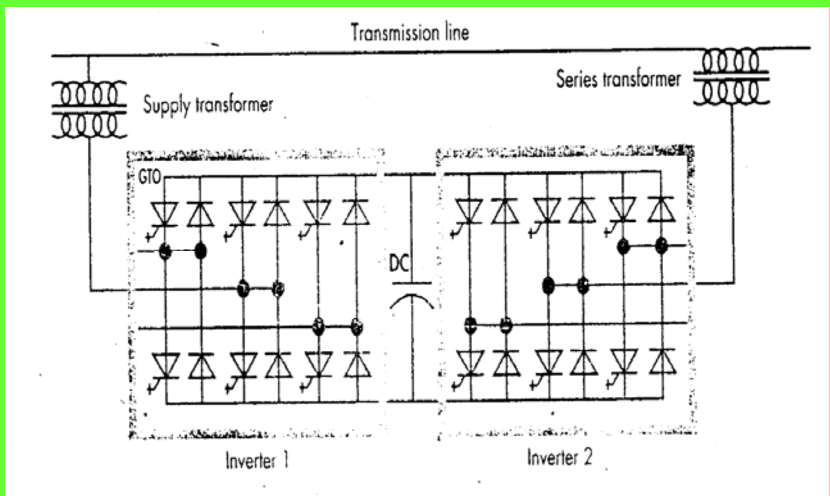
A thyristor controlled phase angle regulator (TCPA)



Unified power flow controller (UPFC)



A UPFC with all 3 phases shown



- Reactive power (MVAR) control devices:

- control of injections from generator using AVR
- Control of flows in lines using (i) magnitude regulating transformers or (ii) UPFC

- In addition to bus voltage and line flow control, FACTS devices can also damp out unwanted oscillations and hence improve dynamic performance of today's highly stressed power systems.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

Role of SCADA in Power System Operation

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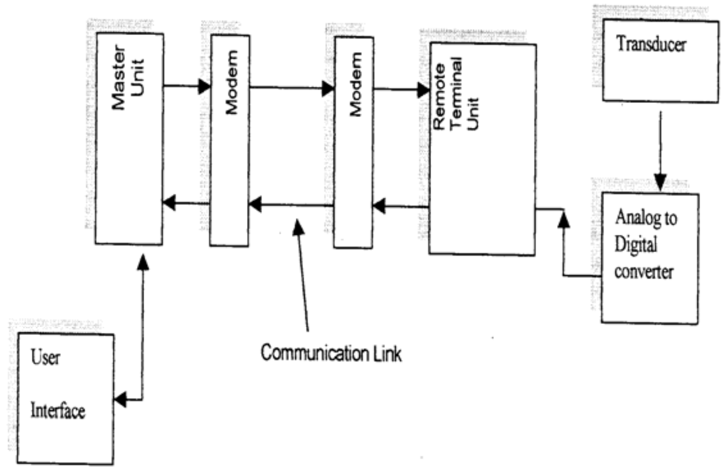
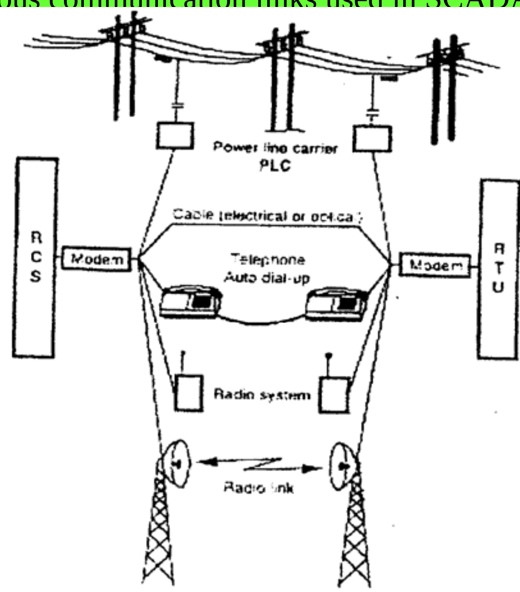
SCADA (Supervisory Control and Data Acquisition) Features

- RTUs
- Data Acquisition and Command implementation
- Electrical and non-electrical data
- Transducer, CT, PT etc.
- Modem, Com. Links, RCS
- Optimization of communication channels
- LAN connected servers in master station
- Hierarchical control

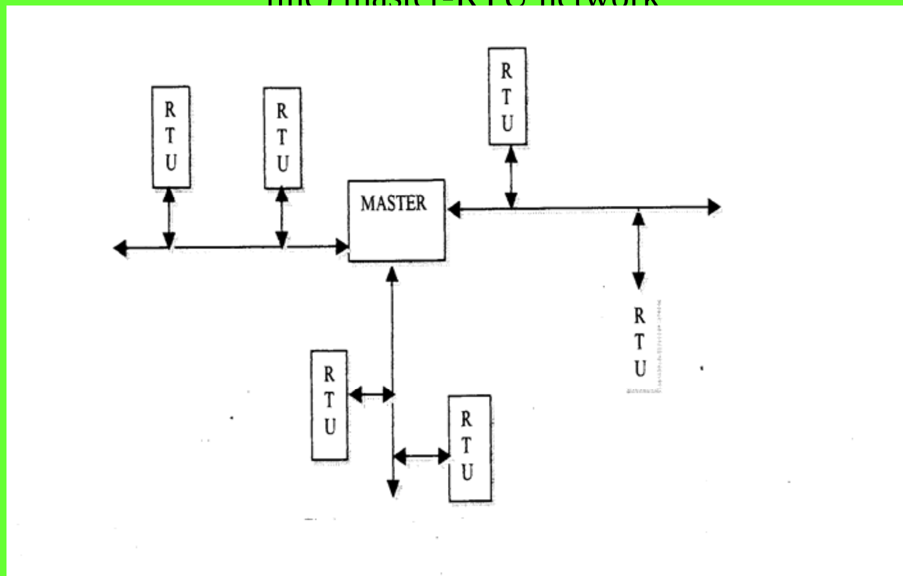
Basic structure of SCADA



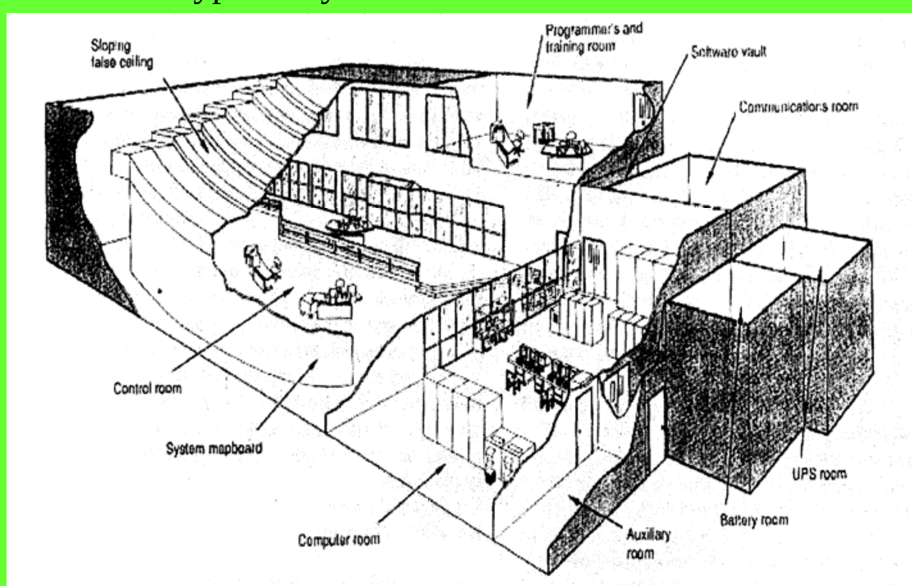
Various communication links used in SCADA



Combination of radial (star) and multi-point (party line) master-RTU network



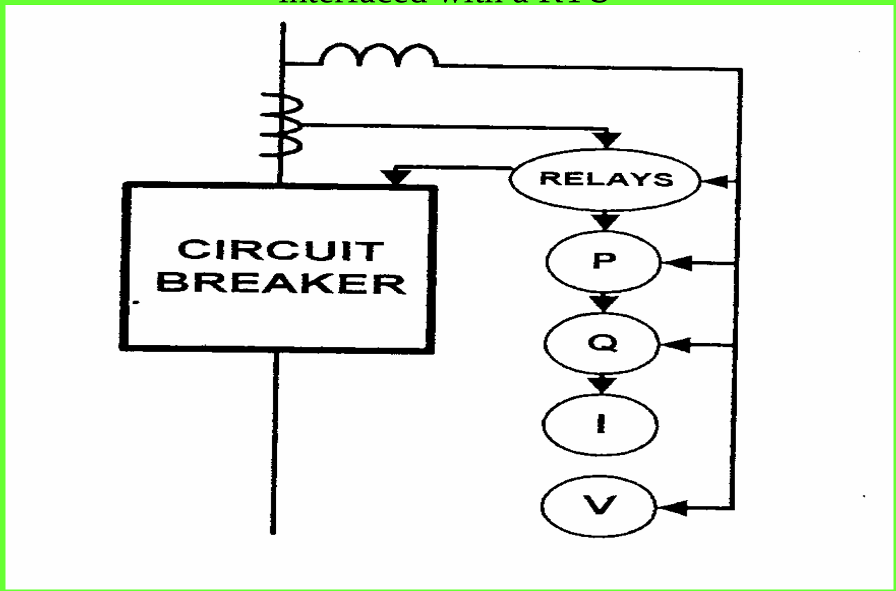
A typical layout of SCADA control centre



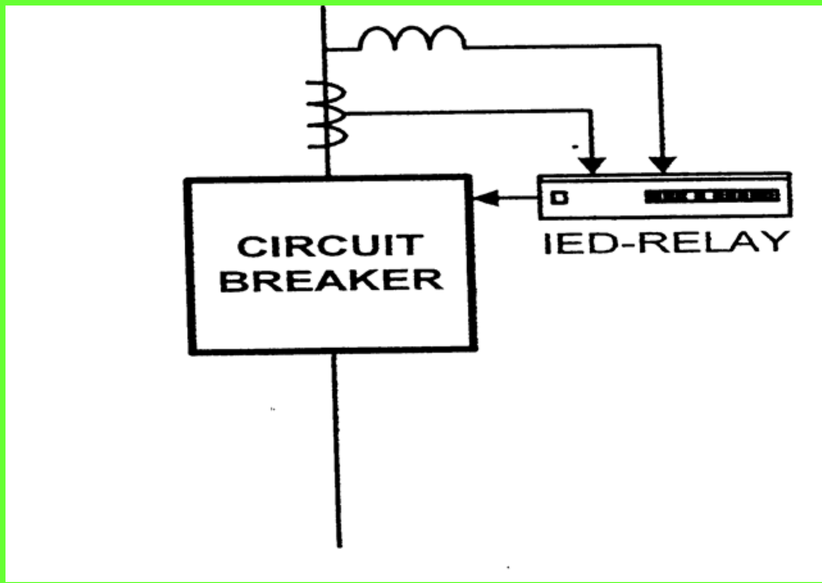
Recent developments and issues in SCADA

- RTU vs. IED
- Use of GPS
- Need of Standard Protocol

Connection of relay and transducers which are interfaced with a RTU



Direct interfacing between power system and an IED



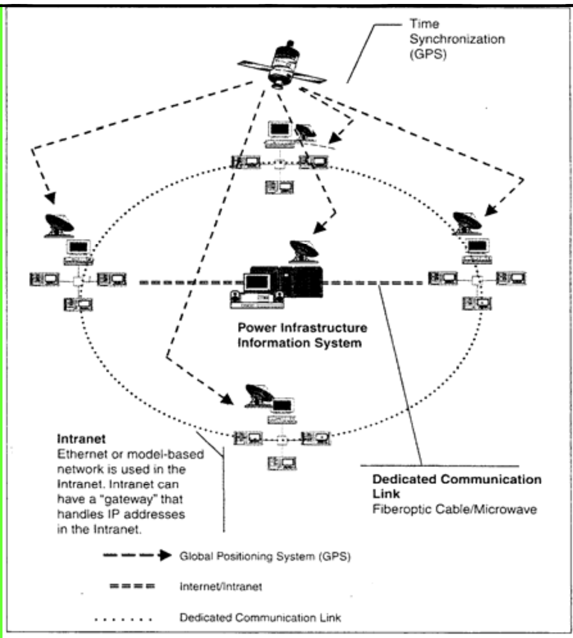
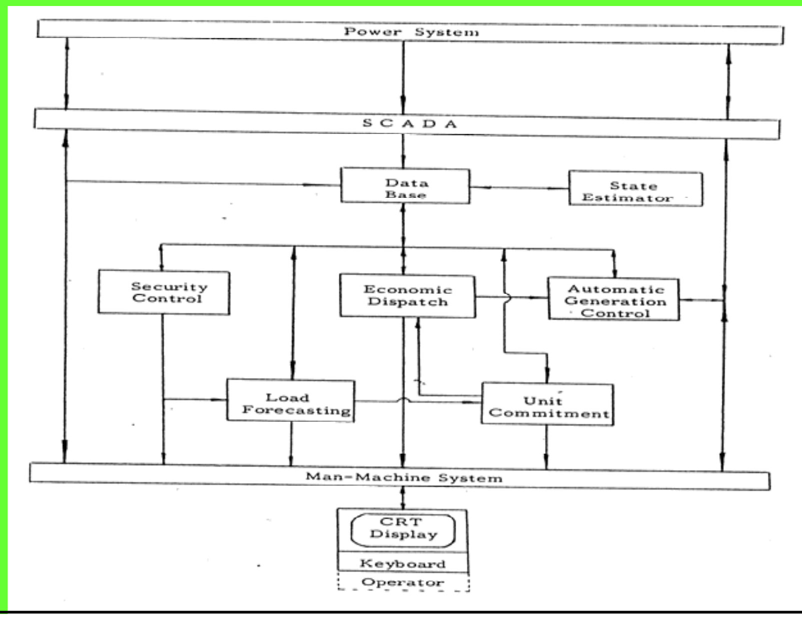


Figure 1. Telecommunications network and the electric power infrastructure (image courtesy of C.-C. Liu, University of Washington)

IEEE CAP; January 2001 21

Basic model of EMS that integrates application functions and SCADA

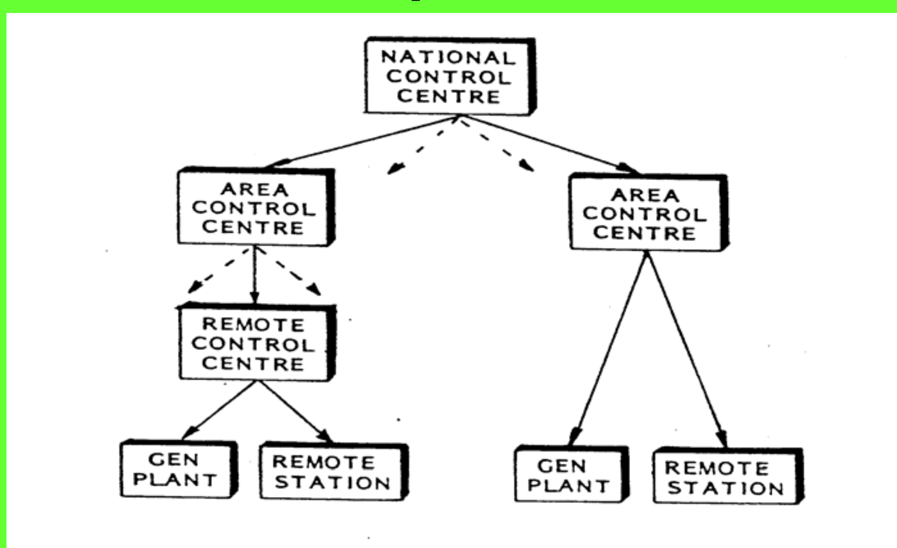


Application Functions of EMS

- Data base: on-line data, fixed data, output of other functions.
- State Estimator: systematically cleans up raw data.
- Load Forecasting: real- time projection (half-an-hour to 24 hours ahead) of demand.
- Security control:monitoring, analysis, enhancement.

- Unit Commitment: usually 24 hours ahead decision on generating units/plants to be kept on or off.
- Economic Dispatch: how to allocate the generation share among committed units most economically.
- AGC: takes into account frequency mismatch, ED decisions and power interchange under contract.

Hierarchical control of a large power system's operation



An example how respective SCADA/EMS system can be used by independent power systems to coordinate their operation in interconnected mode

- Individual system's detailed data can not be made available to one another i.e. the interconnection is not under "power pool" mode.
- So, no "pool control centre" exists. But each system's EMS operators can communicate (voice or computer message) with the neighbouring systems' ones e.g. via WAN.

- The following steps can then be taken.

-Each system runs an economic dispatch (ED) calculations for its own system and demand without assuming any power interchange with neighbours.

-By communicating with each other, the systems with lower incremental cost (IC) and those with higher one can then be identified.

-Then each system will carry out a series of EDs by increasing the demand in each step (if lower IC) i.e. assuming an export or decreasing the demand (MW) in each step (if higher IC) i.e. assuming an import, and determine respective IC in each step.

-In each step the systems will communicate among them only respective IC and demand increment or decrement size (MW).

- If in a certain step the ICs for all the systems are found to be almost equal, the level of interchange (export or import) by each system can be determined from increment or decrement in its demand corresponding to that step.
- This will lead to almost the same conclusions on cost and size of transactions if a pool dispatch were performed considering all the interconnected systems as a single area.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

Unit Commitment Procedure in Meeting the Demand Economically

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What is unit commitment (UC)?

- A procedure based on a heuristic /rigorous /semi-rigorous / artificial intelligence method
- to decide usually 24 hours ahead
- which ones of the available generation units should be turned on or off ,
- when,
- and how long
- so that the total fuel cost for satisfying the forecasted load profile for the next 24 hours can be minimized.

Why it is needed?

- A utility has many generation units from reliability as well as operational needs.
- These are of varying characteristics and operating costs.
- These are at various distances from load centres.
- The daily demand profile is not static.
- A reduction in fuel cost by even 0.5% in a day represents a saving of millions of dollar over one year for a large utility.

Complexities

- A plethora of constraints
- Generation mix i.e. hydro and thermal units
- Scheduled interchanges with neighbouring utilities through interconnections.
- If K units then there are $2^K - 1$ possible combinations to be examined in each stage or interval (e.g. every hour) of the study period (e.g. 24 hours).

Some simplifications

- Make the most of available hydropower (that implies zero fuel cost) within the transmission line limits.
- Given the scheduled interchange, commit the thermal units.
- Fortunately, all of the $2^K - 1$ combinations are not feasible and hence may be ruled out, thanks to many constraints including demand vs. capability.

What are the main constraints to be considered ?

- Spinning reserve
- Minimum up time of units
- Minimum down time of units
- Start-up cost that varies with hours of operation the unit was in.

- Units that must run during certain times of the year
- Limited fuel or obligation to burn a specified amount of fuel in a given time
- Variable capacity of units due to maintenance or unscheduled outages of their components

Methods for UC

- Choice of method is important as the conclusion (i.e. savings in fuel cost) varies from method to method.
- However, none of the methods will result in the true optimal solution while their individual accuracy vary. This is due to assumed simplifications and the way a method takes into account the constraints.
- The most accurate method is not necessarily the one that poses the least computational burden.

Widely used methods

- Priority listing
- Lagrangian relaxation
- Dynamic programming

Priority listing

- The simplest method in respect of computational requirements.
- The units are ranked in descending order of respective full load average fuel cost (a linear input-output characteristics is assumed throughout the operating range).
- Priority in committing the units starts with the lowest ranked one.
- Further enhancements can also be made to include other constraints.

Lagrangian relaxation

- This is somewhat rigorous mathematics based method.
- The UC problem is formulated as minimization of an objective function, that in its simplest form takes into account the fuel cost (F_i), start up cost (S_i) , and on/off status (U_i = 1 or 0) of all the units K in each interval 't' of the window (study) period.

- The minimization is done subject to only two constraints viz. loading constraints (i.e. demand equals total of all the committed generation units' outputs) and units' capacity limits, in each interval.
- The Lagrange function is

$$L = \sum_{t=1 \text{ to } N} \sum_{i=1 \text{ to } K} [F_i(P_i^t, U_i^t) + S_{i,t}]\, U_i^t + \sum_{t=1 \text{ to } N} \lambda^t \left(P^t_{load} - \sum_{i=1 \text{ to } K} P_i^t U_i^t\right) \qquad (1)$$

- Then minimization is done in two steps (or dual optimization) in each interval t.

-Firstly a λ is obtained for which L (excluding P^t_{load} that is constant) is maximized.

-Keeping this λ fixed, P_i^t and U_i^t are adjusted so that L (excluding P^t_{load} that is constant) is minimum subject to the units' capacity limits.

- Other constraints can also be included in the second step of dual optimization.
- Due to convergence problem, Lagrangian relaxation method is run in combination with dynamic programming method in few initial iterations and a heuristic method in the later iterations.

Dynamic programming (DP)

- This is a semi-rigorous method and computationally also efficient.
- The UC for the whole window (N intervals) is divided as a number of optimization subproblems, one for each interval t so that the combined best decision for N subproblems yield the overall solution for the original UC problem.

- This combined with consideration of practical constraints leads to a phenomenal reduction in the number of candidate combinations to be examined by DP.

- In DP, equation (2) is used iteratively starting with the final stage (interval) N and carrying the cumulative minimum cost for each of the feasible combinations in the stage (t+1) i.e. $x_i(t+1)$ backward in time to each feasible combination i in stage t so that the minimum cumulative cost $F_{i*}(t)$ can be found for each $x_i(t)$.

$$F_{i*}(t) = [\min\{f_i(t) + T_{ij}(t) + F_j(t+1)\}_{j=1......xj(t+1)}]_{i=1....xi(t)} \qquad (2)$$

where,

$f_i(t)$ = fuel cost in stage t for its i-th feasiblec combination

$T_{ij}(t)$ = cost of transition from combination $x_i(t)$ to combination $x_j(t+1)$ due to start up or shut down of one or more units.

- In this way eqn. (2) is applied till the first stage is reached.
- The optimal unit commitment schedule from stages 1 to N is then found by tracing the path that joins that specific feasible combination in each stage at which the cumulative cost becomes minimum when compared with cumulative cost at other feasible combinations in the same stage.

An example on UC of a 4-generator system using DP

- In a power system the daily load cycle experiences 1100 MW, 1400 MW, 1600 MW, 1800 MW, 1400 MW and 1100 MW respectively for stages 1 to 6. Each stage consists of 4 hours as shown in Fig. 1.
- There are 4 thermal generation units in the system having loading limits and quadratic fuel-cost characteristics with coefficients given in the Table 1.

Fig.1: Daily load cycle

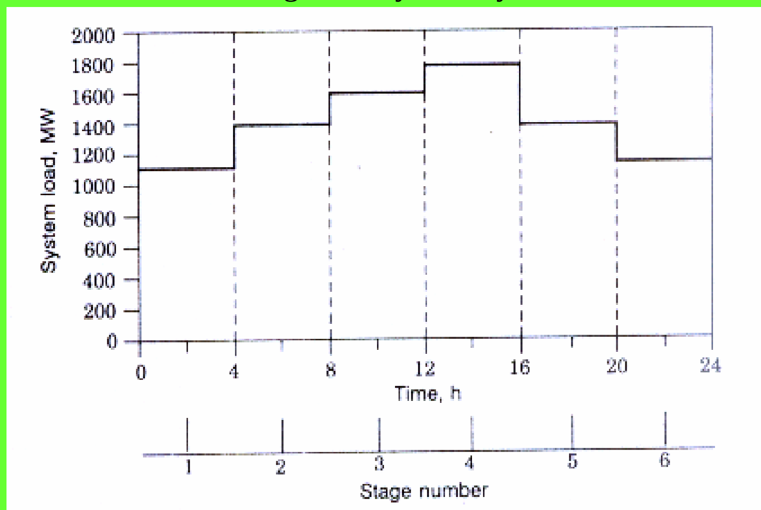


Table 1:Loading limits and cost coefficients of 4 generators

Unit	Minimum loading	Maximum loading	a ($/h/MW^2)	b ($/h/MW)	c ($/MW)
1	100 MW	625 MW	0.0080	8.0	500
2	100 MW	625 MW	0.0096	6.4	400
3	75 MW	600 MW	0.0100	7.9	600
4	75 MW	500 MW	0.0110	7.5	400

- Let us consider that units 1 and 2 be treated as the must-run units.
- Assume that the start-up and the shut-down costs for each unit are $3000 and $1500 respectively.
- Consider that only the must-run units 1 and 2 will run in the 1st and the last (i.e.6th) stages of load cycle.

- Neglect transmission losses.
- Use the dynamic programming approach and determine the optimal unit commitment schedule for the system.

Solution

- First of all, for every stage (t) make an economic dispatch (ED) i.e. find the allocation of generation output for the units in each feasible combinations (within the constraints imposed) $x_i(t)$ and also the corresponding fuel or production cost $f_i(t)$.
- This is shown in Table 2. The way the ED has been done will be illustrated in an example in the next presentation on "Optimal dispatch of generating units".

Table 2: ED results for feasible combinations

Comb.code /stage	Outputs in MW P_1	P_2	P_3	P_4	Total fuel cost $
Stage 1,6					
Pload=1100 MW					
x_1 (1111)	261	385	219	235	45,848
x_2 (1110)	351	459	290	-	45,848
x_3 (1101)	347	456	-	298	44,792
x_9 (1100)	509	591	-	-	45,868
Stage 2,5					
Pload=1400 MW					
x_1 (1111)	351	459	290	300	58,428
x_2 (1110)	464	554	382	-	59,356
x_3 (1101)	464	553	-	383	58,236
x_9 (1100)			Infeasible		

Table 2 /contd.

Comb.code /stage	Outputs in MW P_1	P_2	P_3	P_4	Total fuel cost $
Stage 3					
Pload=1600 MW					
x_1 (1111)	410	508	338	344	70,908
x_2 (1110)	541	617	442	-	68,976
x_3 (1101)	542	618	-	440	67,856
x_9 (1100)			Infeasible		
Stage 4					
Pload=1800 MW					
x_1 (1111)	469	558	386	387	76,472
x_2 (1110)	625	625	550	-	79,184
x_3 (1101)			Infeasible		
x_9 (1100)			Infeasible		

Stage 6

- Now, begin with last stage (N=6). Though there are 4 feasible combinations. But it has been restricted that only the combination x_9 with only units 1 and 2 in ON state is to be considered.
- Apply equation (2) to this stage with only one i.e. x_9 combination as the candidate.
- Since this is the last stage, cumulative cost $F_j(t+1)$ up to this stage is zero.

- Since the first and the last stages are same in respect of demand and commitment (i.e. x_9), the transition cost $T_{ij}(6)$ becomes zero.
- Now, on substituting $f_9(6)$ = $45,868 (for x_9) the minimum production cost at stage 6 i.e. $F_9(6)$ becomes the same.

Stage 5

- Here feasible combinations are $x_i(5) = x_1(5)$, $x_2(5)$, $x_3(5)$
- In stage 6 the feasible combination was only one i.e. x_9
- So eqn. 2 is to be applied by permutation of $x_1(5)$, $x_2(5)$, $x_3(5)$ each with $x_9(6)$.

- As for example,

$F_1(5) = \{f_1(5)+T_{1,9}(5)+F_9(6)\}=$
$\{\$58,428+\$3000+\$45,868\}= \$107,296$

Similarly,

$F_2(5) = \$106,724$

$F_3(5) = \$105,604$

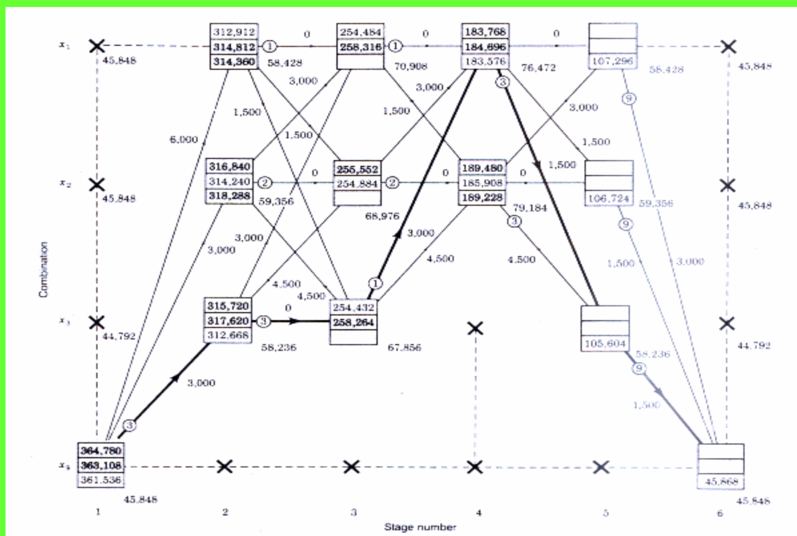
Stage 4

- For this stage more permutations need to be done as there are 3 feasible combinations in stage 5 and 2 feasible combinations in stage 4.
- Applying eqn. (2) for each of x_1 and x_2 with 3 cumulative costs from stage 5 i.e. $F_1(5)$, $F_2(5)$ and $F_3(5)$ we can have minimum $F_1(4)$ and $F_2(4)$.
- All the cumulative costs in each stage and for each feasible combination are recorded in Fig.2.

Stage 3, 2, 1

- Eqn. (2) is applied for each of the stages in the way it was done for stage 4.
- Then it can be found that at stage 1for the lone combination $x_9(1)$ the cumulative cost function that was being carried back from stage 6 will stand at $361,536.

Fig.2: DP solution for the example UC problem



Optimal UC schedule for this example

- If the least cumulative cost path is traced from stage 1 to 6 then it is found that x_9 in stage 1 derives from combination x_3 in stage 2, which in turn derives from x_3 in stage 3, and so on back to x_9 in stage 6. This is summarized in Table 3.

Table 3: UC schedule for the example case

Stage	load level in MW	comb.	Units on/of
1	1100	x_9	1100
2	1400	x_3	1101
3	1600	x_3	1101
4	1800	x_1	1111
5	1400	x_3	1101
6	1100	x_9	1100

- In the example case, the total fuel cost to supply the forecasted load for 24 hours is $361,536.

A note

- The UC problem as discussed here can also be extended for a utility that has scheduled imports through interconnections with neighbours or power purchase agreements with IPPs.
- This can be done by treating the “import” / “agreed purchases” as equivalent must-run unit capacity in the corresponding intervals (stages).

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

Optimal Dispatch of Generating Units

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Reliability and Operational Aspects of a Regional Grid, July 15-17, 2004, Dhaka

- **What is this?**
- This is popularly also known as economic dispatch (ED).
- This is a computational procedure by which the generation is allocated among the units that have already been brought on-line i.e. committed in an interval of time (stage) such that the production cost in that stage is the optimum i.e.minimum subject to some constraints such as demand and transmission losses.

- **How does it relate to UC?**
- Indeed, UC also requires that an ED be performed in each stage. However, that is done for each of many feasible combinations not a specific one and yet to be implemented.
- Furthermore, ED when done as a part of UC it allocates generation outputs among the candidate units to meet a forecasted load, and usually does not consider even line losses.

ED for generators within a plant

- Transmission losses do not arise in this case.
- If the generators are loaded at such values that their respective incremental costs (λ_i) are equal to each other and the demand (P_D) is equal to sum (P_T) of their outputs, then this will result in an ED.

- The incremental cost λ_i of a generator (i-th unit) at its any output P_i is the additional cost per hour to increase the output by 1 MW i.e. P_i +1 MW.
- This is variable and depends on the fuel characteristics (input-output curve) i.e. MBtu/h vs. MW curve for a thermal unit.
- $\lambda_i = df_i/dP_i$ (1)

- The fuel cost in $/h is obtained by multiplying the fuel input by the cost of fuel in $/MBtu.
- Typically the fuel cost curves are quadratic and very often approximated in terms of vendor supplied coefficients as follows.
- $f_i = (a_i/2)P_i^2 + b_iP_i + c_i$ $/h (2)

- $\lambda_i = df_i/dP_i = a_iP_i + b_i$ $/MWh (3)
- For ED,

$\lambda_i = \lambda = a_TP_T + b_T$; i=1,2…..K (total no.of generators under ED) (4)

λ is also termed plant λ.

where

$a_T = \{\sum_{i=1 \text{ to } K} (1/a_i)\}^{-1}$ (5)

$b_T = a_T \{\sum_{i=1 \text{ to } K} (b_i/a_i)\}$ (6)

$P_T = \sum_{i=1 \text{ to } K} P_i = P_D$ (7)

Individual economic (optimal) output is then

$P_i = (\lambda - b_i)/a_i$ (8)

An example of ED for a power plant

- Let the example given in UC be considered.
- Let the ED be made for stage 1 with combination x_1 (all the units to be run) for a P_D=1100 MW.

Table 1:Loading limits and cost coefficients of 4 generators

Unit	Minimum loading	Maximum loading	a ($/h/MW^2)	b ($/h/MW)	c ($/MW)
1	100 MW	625 MW	0.0080	8.0	500
2	100 MW	625 MW	0.0096	6.4	400
3	75 MW	600 MW	0.0100	7.9	600
4	75 MW	500 MW	0.0110	7.5	400

- Solution:
- Using equations (5), (6) and a,b,c coefficients of 4 generators from Table 1

$a_T = 2.3805 x 10^{-3}$

$b_T = 7.4712$

- Using equation (4) and $P_T = P_D = 1100$ MW

$\lambda = 10.090$ $/MWh

- Using eqn. (8), λ, and a,b, c of each unit, the ED outputs are obtained as

$P_1 = 261$ MW

$P_2 = 385$ MW

$P_3 = 219$ MW

$P_4 = 235$ MW

- Substituting the ED outputs in eqn. (2) respective fuel costs are obtained as

f_1= 2861 $/h

f_2= 3565 $/h

f_3= 2570 $/h

f_4= 2466 $/h

- Total generation cost in stage 1 that comprises 4 hours would be 4 times the sum of f_1 to f_4 i.e. $45,848

ED for a number of plants

- Each plant may be considered to have a lumped output P_i and a plant incremental cost λ_i.
- Transmission losses now must be considered as a cheaper plant with low incremental cost may be far from the load centre.
- If the plants are allocated outputs P_i such that the product of respective λ_i and penalty factor L_i is equal to that of another plant then ED has been achieved.

- $\lambda_i L_i = \lambda$; i=1,2…….No. of plants (9)

λ is now termed 'system λ'

- It is the penalty factor that takes into account transmission losses in ED among plants.

$L_i = 1/(1-\partial P_L / \partial P_i)$ (10)

where P_L is total transmission loss in the system

$P_L = \sum_{i=1 \text{ to } S} \sum_{j=1 \text{ to } S} P_i B_{ij} P_j$ (11)

- $\sum_{i=1 \text{ to } S} P_i = P_D + P_L$ (12)

- Eqn. 11 is a typical equation that expresses transmission loss in terms of B coefficients for S No. of sources connected to the transmission network.
- The source No. S must also include the additional points of power import into the transmission network such as scheduled import through interconnections or from hydropower plants. Because these imports contribute to P_L and hence affects distribution of remaining loads among the thermal plants.

- This means for a 5-thermal plant system with 3 hydro plants and 7 interconnections, the loss coefficient (B) matrix will be 15x15 though only 5 thermal plant outputs to be obtained through ED.
- Usually a number of B coefficients sets corresponding to typical parts of the daily load profile are obtained by a series of off-line load flow solutions, and used in different stages (intervals) for ED.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

Interfacing of Functions Related to Economic Operation of Interconnected Power Systems

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Application functions directly related to economic operation

- Unit Commitment(UC): usually 24 hours ahead decision on generating units/plants to be kept on or off.
- Economic Dispatch: how to allocate the generation share among committed units.
- AGC: attempts to remove frequency mismatch, implements ED decisions and power interchange under contract.

Fig.1 Underlying logic of an AGC scheme in each of the interconnected areas (systems)

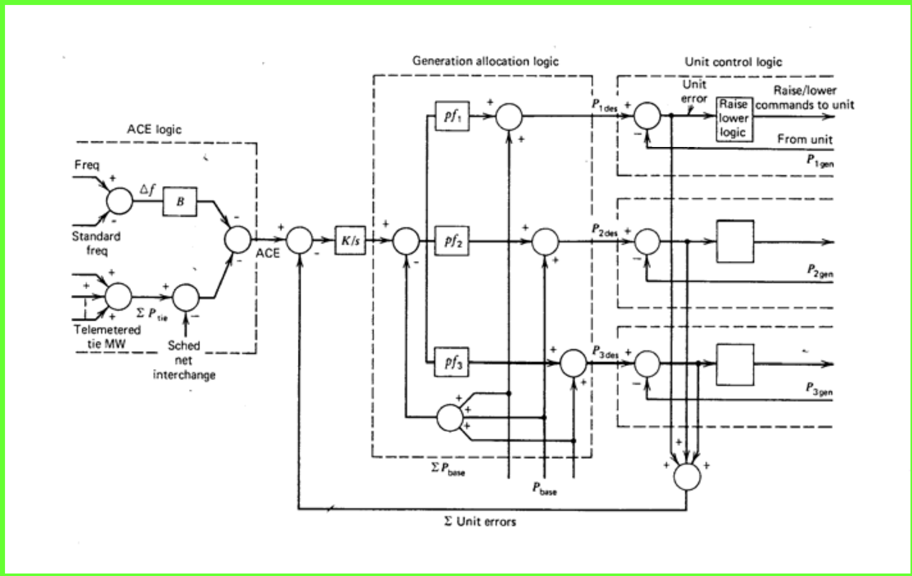
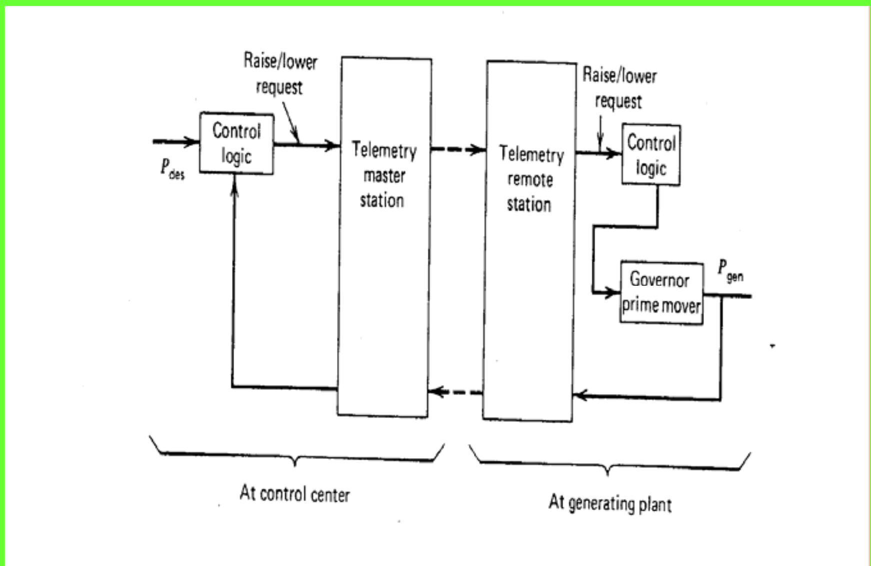


Fig. 2 Use of SCADA in generation control



Role of ACE (Area Control Error)

$$ACE_i = \sum(P_{it,actual} - P_{it,scheduled})_t - B_i \Delta f \qquad (1)$$

where t implies all the tie lines (interconnections) between the area 'i' and other areas.

- The ACE of each area is to be zero.
- If there is a loss of generation or change in demand the ACE of only that area increases to such a value that the remaining generators, committed on-line in that area, will be forced to increase generation.
- ACE concept is effective only if the changes are such that the systems remain in steady state.

Role of participation factor (pf)

- ACE in each area serves to indicate whether total generation in the area needs to be raised or lowered.
- Now, the problem is that once having decided the base point generation (P_{ibase}) of each unit by an ED at a regular interval, how to reallocate among the units the change in total generation (ΔP_{total}) before the next interval?

- The solution is a pre-calculated participation factor (pf_i) for each unit so that

$$P_{ides} = P_{ibase} + pf_i \times \Delta P_{total} \qquad (2)$$

where,

P_{ides} = new desired output from unit i

$$\Delta P_{total} = P_{new\ total} - \sum P_{ibase} \qquad (3)$$

- The AGC control logic is also driven by the unit errors i.e. deviations of each generation unit from the desired economic output P_{ides}
- To do the above, the sum of the unit errors (also termed SCE) is added to the concerned area's ACE to form a composite error signal that drives the entire control system. This is what shown in Fig.1 that combines UC-ED with AGC.

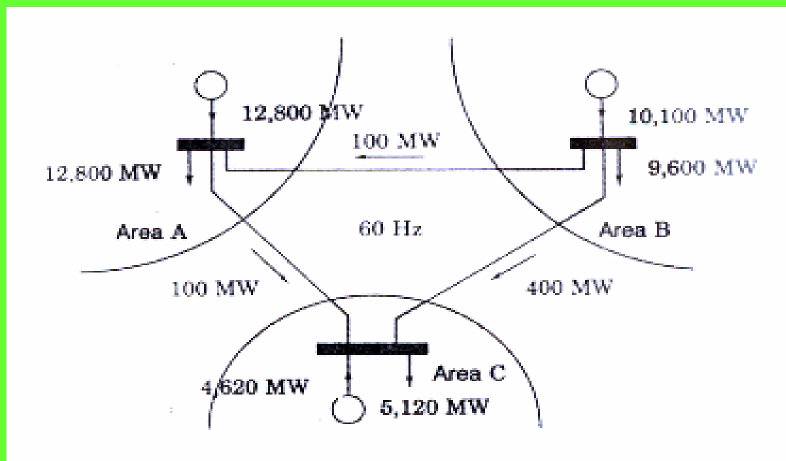
An example of Steady state operation of AGC for three systems that are interconnected

- Three interconnected 60 Hz control areas with autonomous AGC systems have respectively the following aggregate speed-droop (R) characteristics, on-line generation capacities (S) and frequency bias settings (B). Each area has a zero frequency-sensitive load coefficient (D).

	R (p.u.)	S (MW)	B (MW/Hz)
Area A:	0.0200	16,000	-12,000
Area B:	0.0125	12,000	- 15,000
Area C:	0.0100	6,400	- 9,500

- Each area has a load level equal to 80% of its rated on-line capacity. For reasons of economy, area C is importing 500 MW of its load requirements from area B, and 100 MW of this interchange passes over the tie lines B-A-C. Area A has a zero scheduled interchange of its own. The scenario is as in Fig. 3.

Fig.3: Operation scenario in a 3-area interconnected system



- i)What is the system frequency deviation (in Hz) and the generation changes (in MW) in each area when a fully loaded 400-MW generator in area B goes into forced outage?
- ii)What is the ACE (in MW) of each area before AGC action begins following the loss of the 400-MW generator in area B. Neglect losses in each area?

Δf (i.e. change in frequency in Hz) = ΔP (i.e. load change in MW)/ SUM (4)

where,

- ΔP is negative for addition in load or loss of generation
- ΔP is positive for loss of load or surplus of generation

- SUM = $\sum((1/R)+D)_i$; i= 1....No. of areas.
- R_i (in Hz/MW) = (R_i (in pu) x f_0) / S_i (i.e. Rated MW capacity as base)
- Δf (in pu) = Δf (in Hz) /f_0 (rated frequency)
- Individual generation change (ΔP_{gi}) in each area in response to load change is given as

ΔP_{gi} (in MW) = Δf (in Hz) /R_i (in Hz/MW) (5)

i) The loss of the 400 MW is sensed by other on-line generators as an increase in load leading to a decrease in frequency given below, as determined by eqn. (4).

Δf = - 0.01 Hz i.e. $-10^{-3}/6$ pu on $f_0 = 60$ Hz basis

ii)The decrease in frequency leads to initial governor action of each of the remaining on-line generators in each area and causes increments in their outputs given below, as determined by eqn. (5).

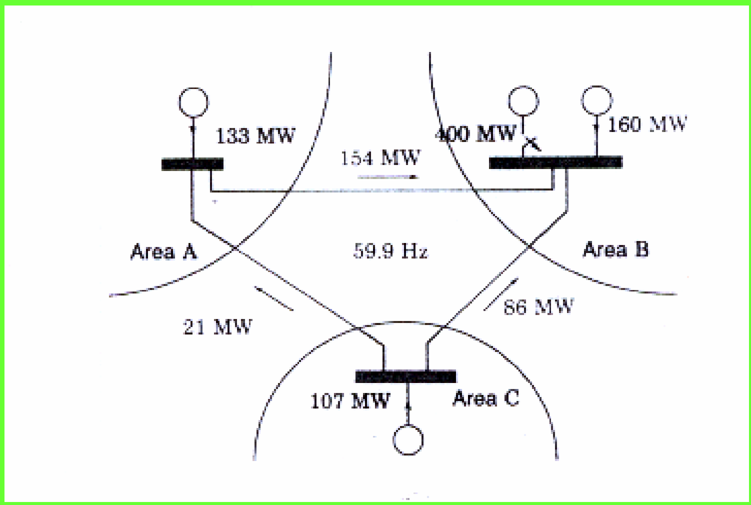
$\Delta P_{gA} = 133$ MW

$\Delta P_{gB} = 160$ MW

$\Delta P_{gC} = 107$ MW

- The increments in generations of the 3 areas following a loss of generation in area B and before AGC acts, will cause a redistribution of flows over the interconnections as in Fig. 4.

Fig. 4: Scenario after loss of a generator in the exporting area B



The ACEs in each area is then given below as determined applying eqn. (1).

$ACE_A = 13$ MW

$ACE_B = -390$ MW

$ACE_A = 12$ MW

Inferences:

- The increments in all 3 areas' generation is for a momentary period only.
- The ACE in area B where generation loss occurred is very high, and will command though AGC action the remaining on-line generators in B to increase their generation to make $\Delta f = 0$ for all the areas.

- Once the frequency is restored to original 6o Hz, the generations in other areas A and C where ACEs are significantly much low (ideally zero) will be restored to their original values.

- The unavoidable or inadvertent energy interchanges (accumulated over a period) due to tie line flows beyond contract for the momentary time can be paid back either in cash or in "energy for energy", on terms mutually agreed upon by the interconnected utilities.

Concept and Assessment of System Security

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Economy vs. Security

- "Security" must prevail over "economy"
- Considering mere the cost characteristics, minimum up/down time etc. of plants and line losses in making UC (Unit Commitment) and ED (Economic Dispatch) may result in cost optimization (i.e. economy) but not in "secure operation" of an interconnected or any power system.

- Security refers to a mode of operating a system such that at any time if any component (e.g. line/transformer/generator) fails the system will not experience “cascaded outage” or blackout.
- The question is why should security get so much importance when the reliability aspect has been considered at the planning stage?

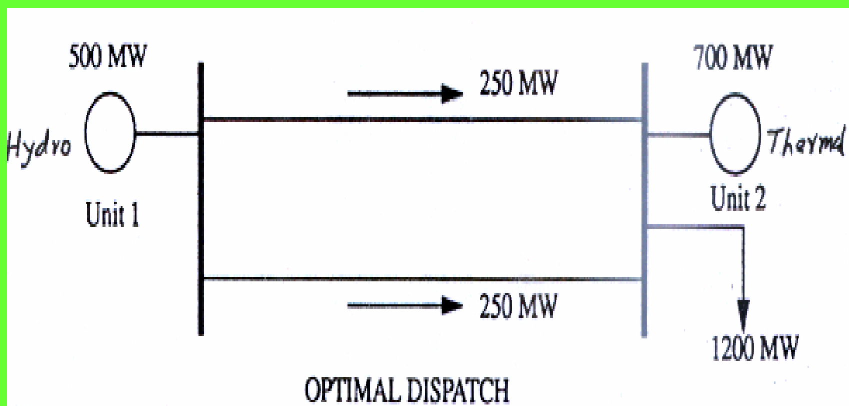
- The answer is “simple”.
- Studies carried out at the planning stage years or even days ahead with respect to certain conditions can not cater to all the loading situations, generating patterns and the wide range of outages (contingencies) likely to arise when the system actually operates.

- A hypothetical solution can be provision of "highly adequate" reserve margins in generation and transmission capacities at the planning stage.
- But as reserve margin represents a large investment in spare (standby and uncommitted i.e. not in operation) equipment, this has to be limited.

How will security affect economy?

- A good example is a simple system as in Fig. 1 in which a hydro plant (being cheap) is committed and allocated 500 MW to supply over a double circuit line to a load centre that has 1200 MW demand. Each circuit has a thermal loading capability of maximum 400 MW.

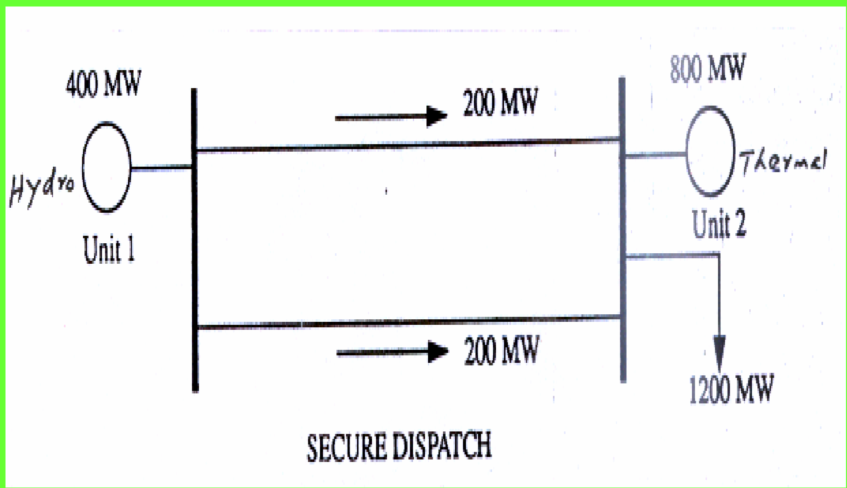
Fig.1: Economic dispatch in a power system



- The operating condition in Fig. 1 represents an optimal or economic dispatch (ED). If one circuit trips due to a fault, such an operation will evidently result in overloading of the remaining circuit by an extra 100 MW that may also eventually trip.
- So ED may lead to insecure operation if the contingencies and constraints (e.g. line loading limit) are not considered.

- A solution to an insecure ED for the system in Fig. 1 is that shown in Fig. 2 where the cheaper hydro is allocated 100 MW less. As a result in the event of a contingency like outage of one circuit, this operating condition will not lead to any collapse of the system. This is called “secure dispatch”.

Fig.2:Secure dispatch in a power system



- A comparison of Figs. 1 and 2 tells us : better loose some “profit” but don’t risk “blackout”.
- This is what security i.e. run the system thinking of contingencies ahead of their occurrences.

How to implement security?

- Indeed, many utilities are practicing security concept in a primitive way. Even this does not involve ICT (information & communication technology) gadgets and sophisticated “3M” method i.e. monitor-manipulate-maintain.
- Rather, a thumb rule “load each circuit of a line to a maximum of half its thermal loadability” (i.e. as in Fig. 2) is followed.

- Similarly, “commit sufficient generation to maintain enough spinning reserve to compensate against a loss of a generation unit” is another thumb rule.

- However, the primitive way is too conservative in today’s context and compromises economy too much.
- Furthermore, adjustments of generation throughout a large system to effect even the thumb rules is beyond the capability of operators not aided by SCADA system.

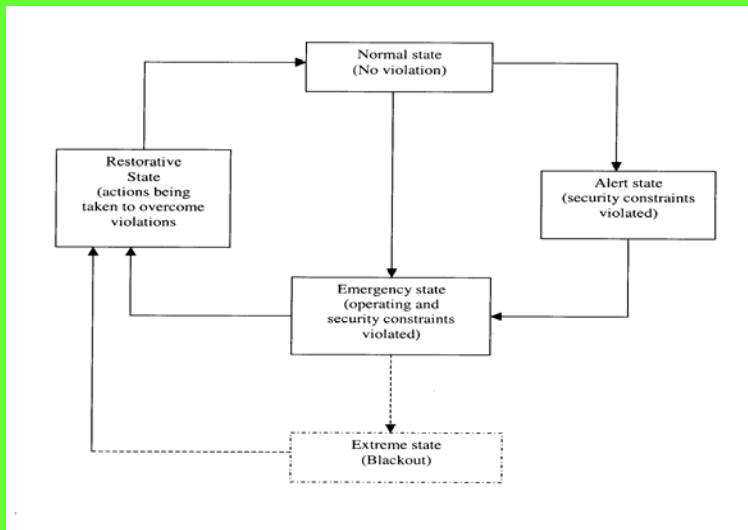
Problems in implementing security

- Large system size
- 'Infinite' number of contingencies
- Speed limitations of the analytical /heuristic tools for analyzing the effects and taking measures against so many contingencies even on today's fast processors.

Real-time compatible solution

- Monitor to classify the system operating condition into one of the 4 states viz. 'normal', 'alert', 'emergency' and 'restorative'.
- Screen the contingencies
- Security constrained optimization

Figure 3 Typical classification of power system security related states



What are the constraints?

- Basically three sets of constraints viz. operating, load and security constraints.
- The operating constraints comprise mainly the operational limits on system variables and apparatus, for instance voltage limit, generator loading limit, transmission line thermal limit, tap position limit and so on.

- The load constraints mainly refer to customers’ total power demand.
- The security constraints are mainly the minimum reserve margin in generation and transmission capacity that is committed (i.e. in operation). These are also termed respectively “spinning reserve” and “transmission margin”.

- A system is in the normal state when all the constraints are met such that the occurrence of any credible but unforeseen disturbance or contingency (e.g. loss of line /generator /transformer/load) will not lead the power system to the emergency state.

- In emergency state the operating and security constraints are violated and the load constraints are not necessarily satisfied. “Blackout” is an extreme version of emergency state.

- In alert state security constraints are violated.
- Notably, many utilities in South Asian countries lack in requisite spinning reserve and hence are always in alert state.

- A system in normal state can go to alert or emergency state when any of the security constraints are violated.
- If a sufficiently severe disturbance takes place before control action can be taken, the system in the alert state enters the emergency state or its extreme version i.e. blackout state.

- The restorative state is a “transit” state between the emergency or blackout state and the normal state.
- This is associated with the period in which actions (ranging from fast valving, dynamic braking, etc. to load shedding, islanding, resynchronization etc.) are taken to bring the system from the emergency/blackout back to the normal state.

Contingency screening

- Do not bother the myriads of contingencies rather identify / select only a few of them that pose potential threats i.e. critical cases. Such a screening technique may involve simple DC load flow or linear sensitivity factors to correlate the effects on system to the contingency e.g. outage of a generator or line. Fast decoupled AC load flow is also used occasionally.

Security constrained optimal power flow (SCOPF)

- Run an SCOPF i.e. make a series of ED for each of the selected contingencies subject to the load flow equations, constraints on line flow, bus voltage, tap change, spinning reserves etc.

Difference between ED, OPF and SCOPF

- Normal ED optimizes only fuel cost considering generation unit capacity related constraints, demand and line losses.
- OPF optimizes fuel cost or line losses subject to the load flow equations and operational constraints.
- SCOPF considers contingencies and security constraints in addition to what is considered in OPF.

Outcome of SCOPF

- This will lead to a preventive operating strategy for a system identified to be in alert state.
- The preventive measures comprise any or all of the means such as redispatch of generation, VAR injections, shifting line flows or switching lines, transformer tap adjustments, and rescheduling (there must be provision for this in the contract) interchanges with neighbours so that the security constraints are not violated in the event of actual occurrence of any contingency.

Steady state and dynamic security

- Let's refer back to Figs. 1 and 2.

-When a circuit would go into forced outage (i.e. a major disturbance), it was shown that the system would still operate with the other circuit exceeding (Fig. 1) or remaining within (Fig. 2) its normal loading limit.

-But the possibility that such a major disturbance can lead to loss of synchronism i.e. transient stability of the generators, has been overlooked.

-OR

It has been assumed that the generators' swings subsided (transient stability maintained) and the system has gone to steady state.

- So if contingency screening is done with the assumption of "regaining steady state condition following a contingency", it is termed steady state security assessment.
- On the contrary, if contingency screening takes into account the transient stability aspect following a contingency, it is termed dynamic security assessment.

- Usually screening the contingencies for dynamic security assessment involves various analytical / heuristic/ AI (artificial intelligence) methods based on transient stability model i.e. swing equations of generators.

- If a for a contingency the system retains both dynamic and steady state security only then it can be screened out.
- “Blackout” is the manifestation of violation of dynamic security.

- SCOPF will enhance both dynamic and steady state security for a selected contingency if also the transient stability model is considered in it besides the load flow model.

Secure Operation of Interconnected Utilities

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Benefits of interconnected systems (regional grid)

- Avoided capacity acquisition
- Increased reliability
- Profit to all the parties whether selling or buying or even wheeling energy

- The benefits are achievable in any mode of management (e.g. power pool with a central dispatch office or just a brokerage office / independent multilateral or bilateral negotiations) and under any pricing policy (e.g. actual cost plus split the saving).
- However, the magnitude of overall benefits may vary in the above cases.

Validity of the benefits

- Following assumptions/simplifications form the premise which poses interconnection as beneficial.

- Use of aggregated generation and reduced transmission network model, mainly the tie lines, in benefit related analyses.
- The power (capacity) and energy interchanges are firm i.e. available whenever required.

- The exporting and importing systems remain in steady state throughout the period of interchanges.
- AGC action is lenient i.e. interchange of more power is allowed in the event of increase in demand or loss of generation in the importing system.

- Both exporting and importing utilities are self supporting in respect of MVAR i.e. voltage stability. This is because MVAR has less mobility compared to MW.

A big question mark?

- If any of the assumptions, many of which are contrary to the practice, does not remain valid then what happens?
- As for instance:
- if the exporting area itself suffers from loss and hence deficit of generation then what?
- if one or all of the circuits of the tie lines go into forced outage then what?

- If VAR support commensurate with magnitude of MW interchange is not available at the importing end then what?
- If the AGC is not lenient and the importing system lacks in generation capacity to absorb rise in its own demand then what happens?

Answer

- A precarious situation will arise and in most of the cases it leads to total blackout in all the systems whether they were exporting/ importing/wheeling energy.
- Even lack of VAR support will not only result in voltage instability in the importing area but eventually lead to angular instability of generators in all the interconnected utilities if a major fault occurs in the command area of any one of them.

Remedial practice

- Indeed, almost all the utilities that are interconnected in the developed parts of the globe, have adequate self generation capacities to combat the uncertainties likely to arise during operation.
- Mainly for economy, they interchange energy.
- Furthermore, possessing an adequate generation capacity offer other benefits such as strength for bargain with other utilities or the power pool.

Example of a "Pseudo-Interconnected System with 5-Areas"

- Indeed, this example has been derived from a study made by this presenter's group on the blackout incident that occurred around 7 pm (peak period) on June 20, 1998 in the Bangladesh Power Development Board grid system.
- The fault developed at the "area-3" side of the interconnector between areas 3 and 5.

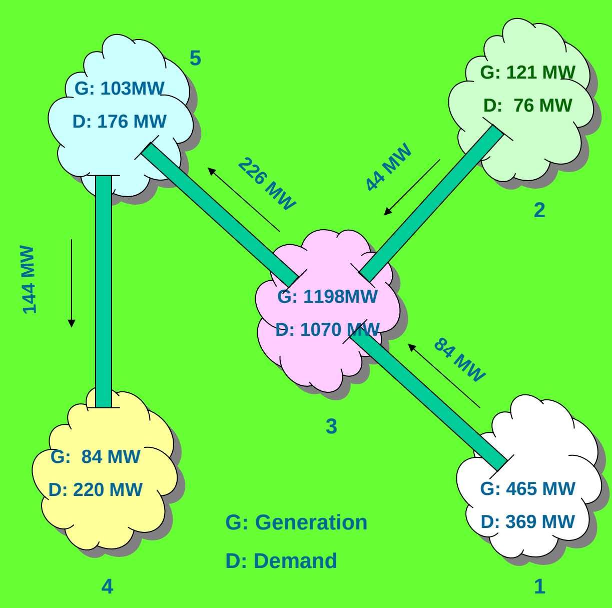

Fig.: Scenario in a pseudo-interconnected system with 5 areas just prior to a fault

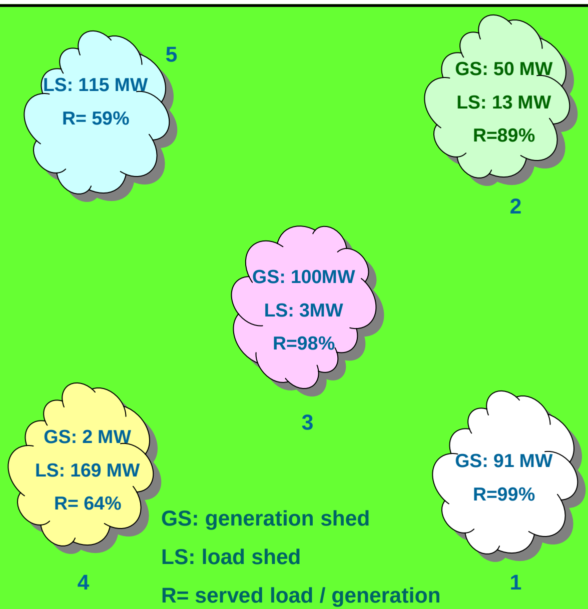

Fig.:Scenario with islanding and load shedding

Lessons from the Example of 5-areas Interconnection

- If the generation capacity in an area is inadequate, it will warrant a higher volume of power import. And, higher the trade volume more is the vulnerability to a blackout (instability of the generators) in all the areas in the event of a major fault.
- Controlled islanding is very often the most effective solution for preventing a blackout.

- If the generation capacity is inadequate in an area, massive load shedding is also necessary in addition to islanding, in order to avert a blackout in that area.
- Each of the interconnected areas must have adequate generation capacity (i.e. more than ‘maximum demand plus losses and spinning reserve’) to avert blackout or massive load shedding, and allow islanded operation in the event of outage of an interconnector or an important internal line in an area.

What to be done in the context of South Asia?

- Excepting Nepal and Bhutan (with large hydro potentials) other countries’ growing demand outstrips their potential and commercially viable resources available for conversion into electricity.
- All the countries lack in funds to build up new generation capacity in public sector.

- Very likely to be reluctant to make available the entire system data to a power pool, relinquishing responsibility of making unit commitment and ED to the power pool, loosing freedom to contract transactions bypassing the pool and undertake customized actions to serve the needs of own customers.

Customized recipe for secure and sustainable operation of South Asian grid

- Each country should make the most of their local energy resources and increase their own generation capacity through IPPs at least to the extent that 30% spinning reserve can be maintained while in operation so that in the event of outages of tie lines or generation in exporting areas, the individual utilities can avert blackout and stand on their own.

- A bare minimum capacity addition in each of the South Asian utilities will also help them overcome their perennial low voltage profile and curtail load shed in respective command area.

- Nepal and Bhutan i.e. the countries with low demand profile but very large hydro (a replenishable resource) potentials can be the major electricity exporting countries.
- Even the remaining countries in this region can invest together on building large power plants in these two countries for regional interchanges. The ownership can be transferred to Nepal and Bhutan.

- The price of electricity (MWh) imported from Nepal and Bhutan can be adjusted against respective investments of the importing countries over a mutually agreed time period.

- The South Asian countries can transact with each other through mutual communication of minimum data derived from respective ED e.g. incremental cost, sellable or purchasable quantum of power/energy.
- This will avoid continuing costs of supporting a central dispatch office required for managing and administering a power pool.

- Each country should make their own security assessment before negotiating every transaction with another country.

- The countries should be liberal at least to an extent that any one can buy power from any other and the necessary wheeling service will be provided by the intermediate utilities (countries) without sacrificing respective system security on mutually agreed upon terms and conditions.

- Another option for the countries with closely distanced borders e.g. India, Bangladesh, Nepal and Bhutan can be provision for both ‘wheeling’ and ‘leasing ROW (Rights of Way) for direct interconnections’.
- Power interchange can be in both modes but not in the same interval of time so that the unused mode can be turned off for that period.

- This can improve reliability and keep the utilities in generation deficit prone countries free from each other’s system disturbances.
- The lease of ROW can be priced and reviewed on mutually agreed upon terms and conditions.

- Notably, lease of ROW for the flow of electrons does not pose any threat to territorial security i.e. unlike leasing a corridor for passage of people.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

ROLE OF RELIABILITY CONCEPT IN A POWER SYSTEM

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SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

- **RELATIONSHIP AMONG SYSTEM RELIABILITY, SYSTEM COST AND COST OF POWER INTERRUPTION**
- **SYSTEM COST**
- **QUANTIFICATION OF LOSS OF CONSUMERS DUE TO POWER INTERRUPTION**
- **STATUS OF SYSTEM RELIABILITY IN GENERATION EXPANSION PLANNING PROCESS**
- **CONCLUSIONS**

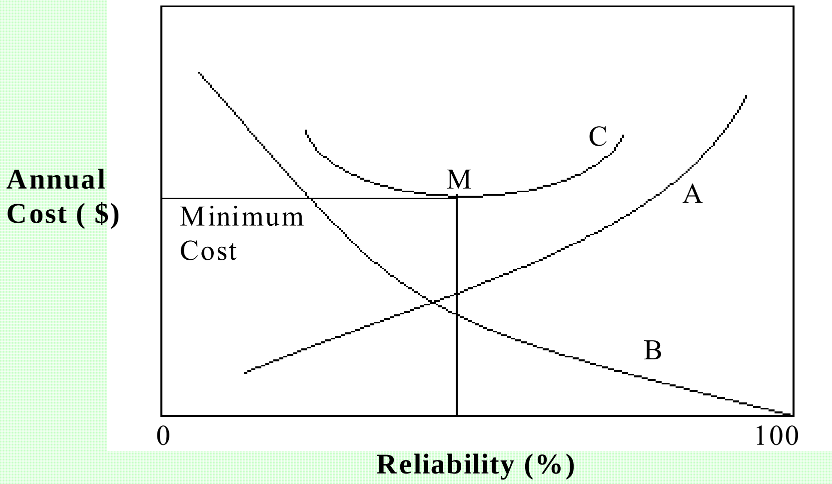


Fig. **Reliability vs. Annual Cost**

A= Cost of utility

B= Loss due to power interruption

C= A+B

COST OF UTILITY

- ❖ Capacity Cost
- ❖ Expected energy production cost
- ❖ Operation and maintenance cost

All these are tangible and methodologies are available to evaluate

QUANTIFICATION OF LOSS DUE TO POWER INTERRUPTION

INTERRUPTION COST COMPONENTS FOR;

RESIDENTIAL CONSUMERS

- Damage of electrical appliances
- Cost of alternative electrical source
- Damage of perishable goods
- Loss due to inconvenience

INDUSTRIAL CONSUMERS

- Damage of electrical appliance
- Cost of alternative electrical source
- Damage of raw materials
- Additional wages

INTERRUPTION COST COMPONENTS FOR;

COMMERICAL CONSUMERS

- Damage of electrical appliance
- Cost of alternative electrical source
- Damage of perishable goods
- Additional wages
- Loss due to reduced sale

Mathematical Model

1. Cost due to the damage of appliances:

$$J_1 = \sum_{i=1}^{N} [J_{11} I(da) + J_{12} \perp (da)]$$

Where,

J_{11} = cost component due to the damage of the repairable item

J_{12} = cost component due to the damage of the irreparable item

N = total number of the damaged appliances

I(da) and $\perp$(da) are characteristic functions

$J_{11} = C_R + C_{RL}$

C_R = Cost of repair =NRC

where, NR = possible no. of repair

C = cost per repair

Cost due to the damage of appliances (Con'd)

C_{RL}= Loss due to the decrease of the life span= $\frac{P_R}{\tau_R}(\tau_R - \hat{\tau}_R) - S_R$

Where,

P_R =Capacity cost

τ_R =Life of repairable appliance

$\hat{\tau}_R$ =Reduced life of repairable appliance

S_R=Salvage value

Similarly

$J_{12} = \frac{P_{IR}}{\tau_{IR}}(\tau_{IR} - \hat{\tau}_{IR}) - S_{IR}$

Cost due to the use of alternative sources

$$J_2 = (P_{AL} - S_{AL}) + C_{FAL} NI_{AL} T_1$$

where, P_{AL} = capacity cost of the alternative source

S_{AL} = salvage value of the alternative source

C_{FAL}= cost of the fuel for a unit duration of use

N_{AL}= number of interruption during the life

T_1 = mean duration of an interruption

Cost of perishable goods

$$J_3 = C_{PG}\, I(D)$$

where, C_{PG} = cost of perishable goods

I(D) = characteristic function

$$\overline{D} = \begin{cases} 1 \text{ if } D \geq \overline{D} \\ 0 \text{ otherwise} \end{cases}$$

$\overline{D}$ is the duration required for an item to be perished.

Cost of inconvenience:

Loss due to the inconvenience from the disturbance in study, computer works and accounting may be expressed as

$$J_{IN_1} = \sum_{i=1}^{M} (C_{TR} + C_M)_i$$

Loss due to inconvenience in sewing,

$$J_{IN_2} = \sum_{i=1}^{K} CT_i$$

Loss due to inconvenience in dinning or cooking,

$$J_{IN_3} = (C_F + C_{OF}) \perp (D)$$

Loss due to inconvenience in family function,

$$J_{IN_4} = C_D + C_F + C_A$$

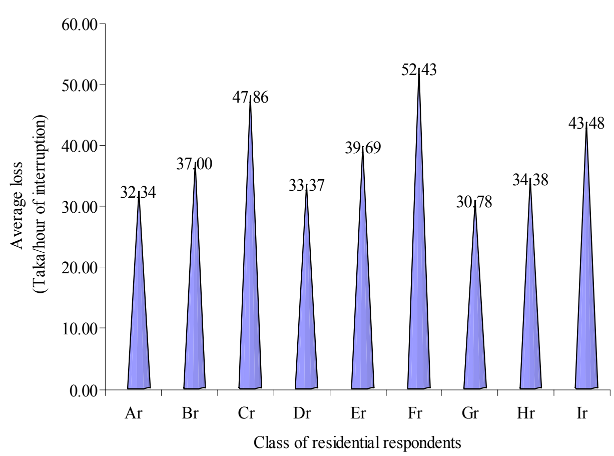
So, total inconvenience cost may be written as

$$J_4 = \sum_i (J_{IN})_i$$

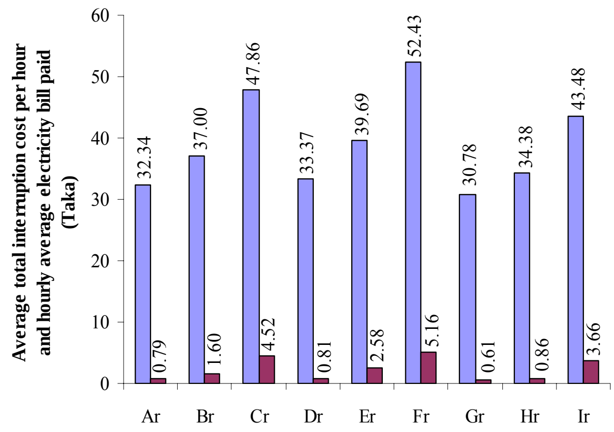
Therefore, the sum of all four cost components J_1, J_2, J_3 and J_4 gives the total cost of interruption during the sampling period for residential consumers.

Classification of Residential Respondents

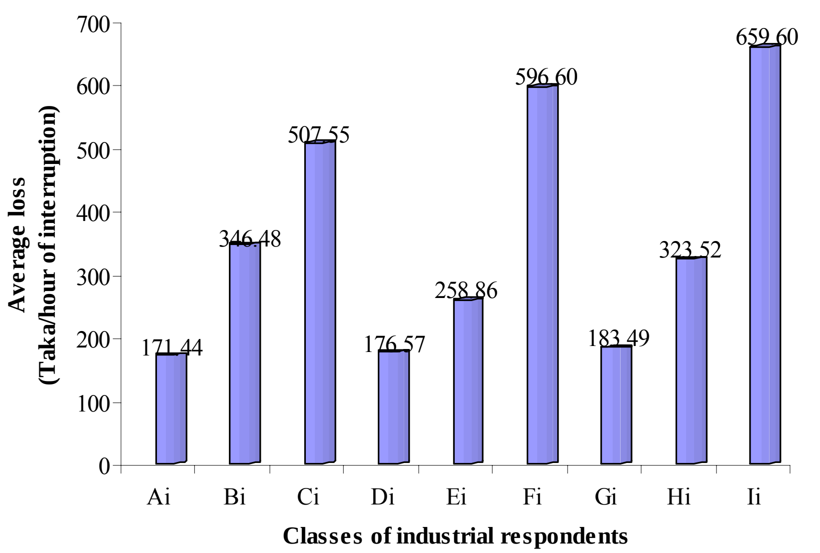
Basis of clasification	Class	Criterion	No. of respondent
Floor area of	Ar	Below 1000	51
house	Br	1000 - 1500	49
(Sq. ft.)	Cr	Above 1500	10
Connected electric	Dr	Less than 3	83
load	Er	3 - 5	15
(Kw)	Fr	Above 5	12
Payment of monthly	Gr	Less than 500	24
electricity bill	Hr	500 - 1000	59
(Taka)	Ir	More than 1000	27



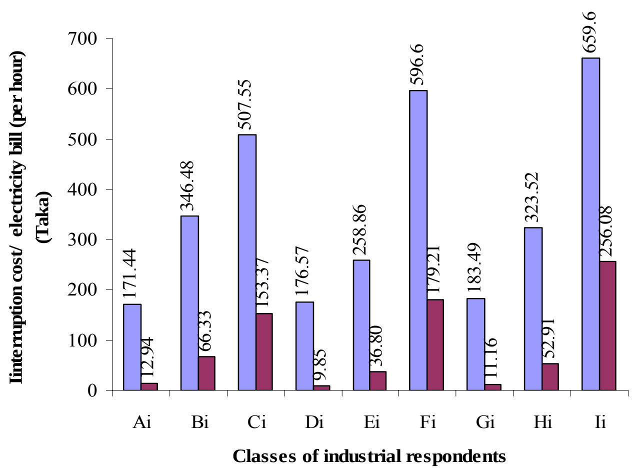
Comparison of loss among different classes of residential respondents



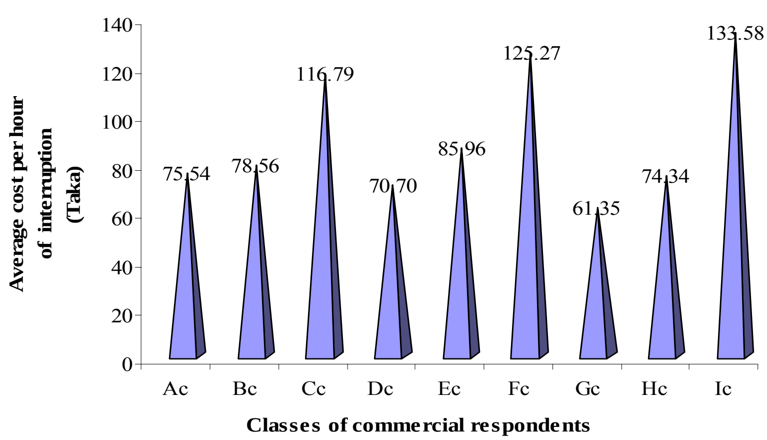
Comparison of interruption cost with the electricity bill for residential respondents



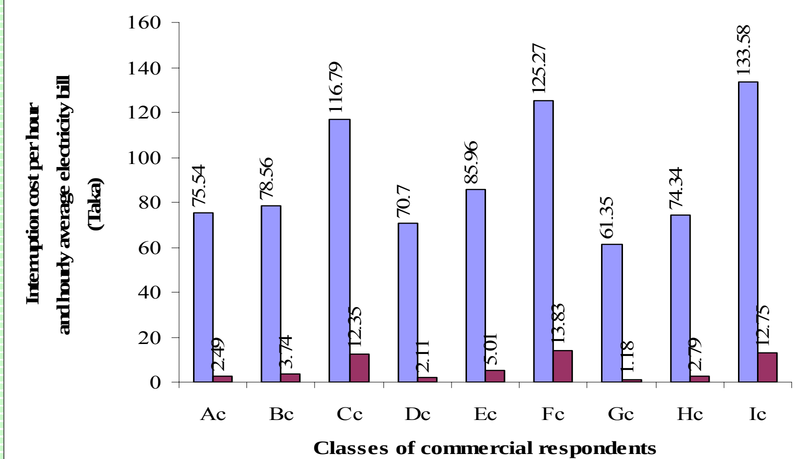
Comparison of cost of interruption among different classes of industrial respondents



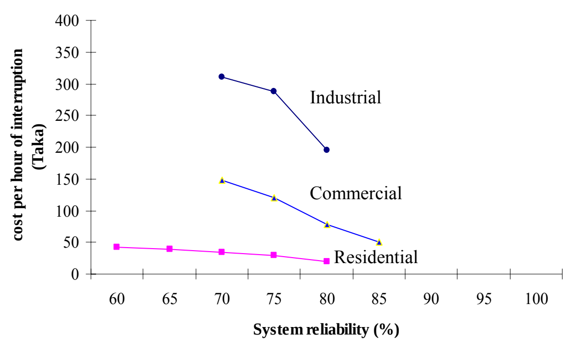
Comparison of interruption cost with electricity bill for industrial respondents



Comparison of cost of interruption among different classes of commercial respondents



Comparison of interruption cost with electricity bill among different classes of commercial respondents



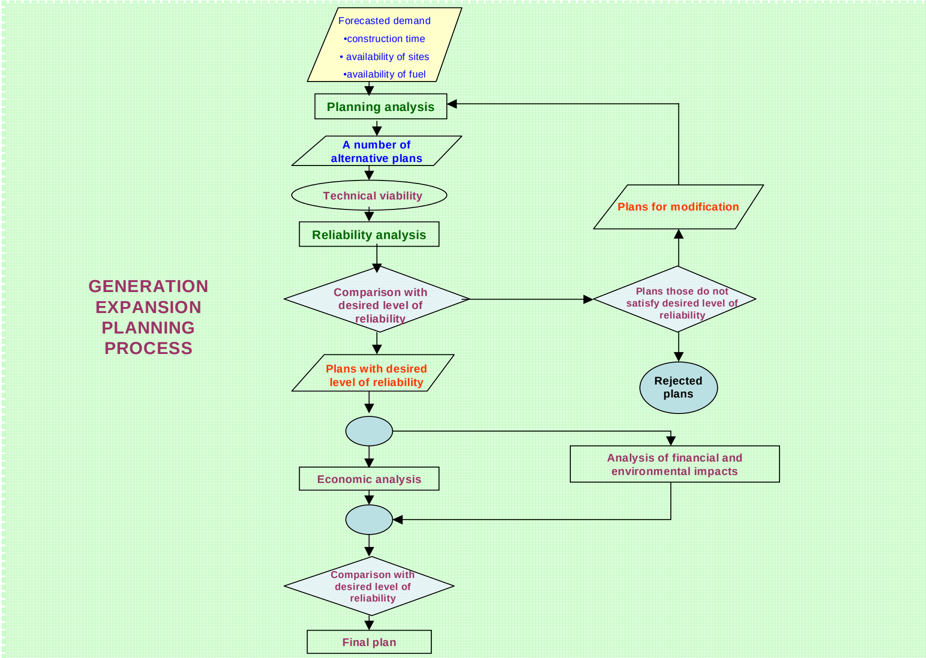
Correlation between interruption costs and system reliability

Comparison of interruption cost with the electricity bill for Residential Consumers

Average cost of interruption					Average electricity bill (Tk/hour of energy consumption)
Incorporating all Cost components		Without inconvenience cost		Without inconvenience and damage of appliance costs	
Tk/hour of interruption	Tk/interruption	Tk/hour of interruption	Tk/interruption	Tk/hour of interruption	
57.08	44.18	10.39	8.38	4.66	0.9

Comparison of the Evaluated Interruption Cost with that of North American Utilities

Utility	Sector of consumer					
	Residential		Industrial		Commercial	
	Average outage cost ($/kwh)	Average outage cost (taka/kwh)	Average outage cost ($/kwh)	Average outage cost (taka/kwh)	Average outage cost ($/kwh)	Average outage cost (taka/kwh)
American 1	0.60	34.80	7.20	417.60	8.40	487.20
Canadian 1	0.46	26.68	15.24	883.92	15.78	915.24
DESA, Bangladesh	0.25	14.50	0.08	4.65	0.36	20.70



CONCLUSIONS

- ❖ BY PROPERLY EVALUATING THE LOSS DUE TO POWER INTERRUPTION THE OPTIMAL LEVEL OF SYSTEM RELIABILITY MAY BE EVALUATED.

- ❖ PRESENT ELECTRICITY TARIFF IS MUCH LOWER THAN THE LOSS DUE TO POWER INTERRUPTION.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

DECISION VARIABLES FOR THE OPTIMAL RELIABILITY LEVEL OF AN UTILITY

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SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

- **FACTORS AFFECTING SYSTEM RELIABILITY .**
- **IMPACTS OF FOR, UNIT SIZE AND RELIABILITY LEVEL ON SYSEM RESERVE AND ALLOWABLE PEAK DEMAND.**
- **IMPACTS OF LOAD MANAGEMENT SCHEMES ON SYSTEM RELIABILITY.**
- **RELIABILITY BENEFITS OF INTERCONNECTION WITH NEIGHBORING UTILITIES.**
- **CONCLUSIONS.**

FACTORS IMPROVING SYSTEM RELIABILITY

- Forced outage rate (FOR) of generating unit
- Selection of unit size
- Interconnection with neighboring utilities
- Application of load management schemes

EFFECT OF FOR

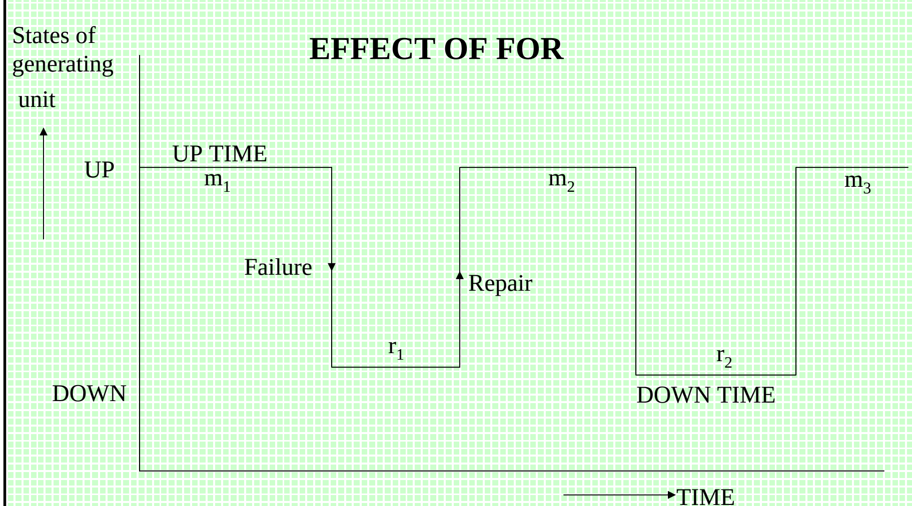


FIG. RUN-FAIL-REPAIR-RUN CYCLE OF A GENERATING UNIT m = Mean up time = $\frac{1}{N}\sum_i m_i$

r = Mean down time = $\frac{1}{N}\sum_i r_i$

λ = Unit failure rate = $\frac{1}{m}$

μ= Unit repair rate = $\frac{1}{r}$

Forced outage rate = FOR = q = $\frac{\lambda}{\lambda + \mu}$

FOR can be reduced by

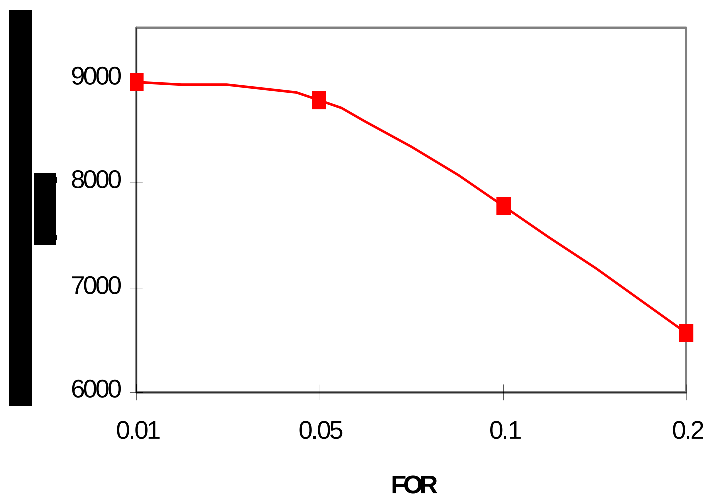
- ❖ Reducing DOWN time with improved repair facilities
- ❖ Increasing UP time with proper maintenance and using quality devices

EFFECT OF FOR

Unit Size (MW)	FOR	LOLP	Reserve (MW)
100	0.01	4×10^{-4}	629
100	0.05	4×10^{-4}	1408
100	0.10	4×10^{-4}	2182
100	0.20	4×10^{-4}	3484

[FOR A SYSTEM OF IC=10,000 MW]

EFFECT OF FOR (CON'D)

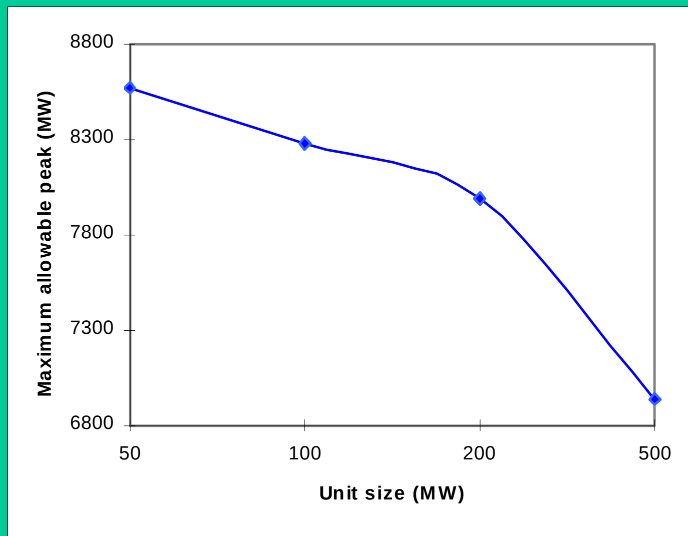


EFFECT OF UNIT SIZE

Unit Size (MW)	FOR	LOLP		Reserve (MW)
50	0.05	4×10^{-4}	= 0.96 days in 10 years	1114
100	0.05	4×10^{-4}		1408
200	0.05	4×10^{-4}		1919
500	0.05	4×10^{-4}		2984

[FOR A SYSTEM OF IC=10,000 MW]

EFFECT OF UNIT SIZE (CON'D)

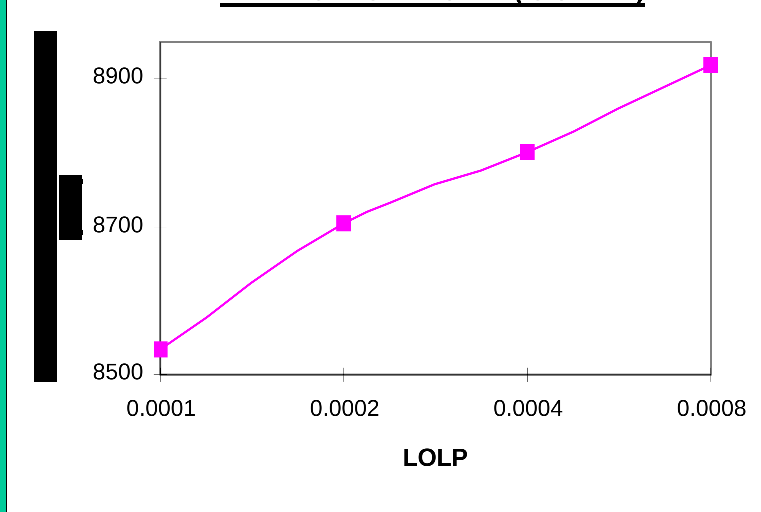


EFFECT OF LOLP

Unit Size (MW)	FOR	LOLP	Reserve (MW)
100	0.05	1 x 10^{-4} (0.96 days/10 years)	1536
100	0.05	2 x 10^{-4} (1.92 days/10 years)	1480
100	0.05	4 X 10^{-4} (3.84 days/10 years)	1408
100	0.05	8 x 10^{-4} (7.68 days/10 years)	1338

[FOR A SYSTEM OF IC=10,000 MW]

EFFECT OF LOLP (CON'D)



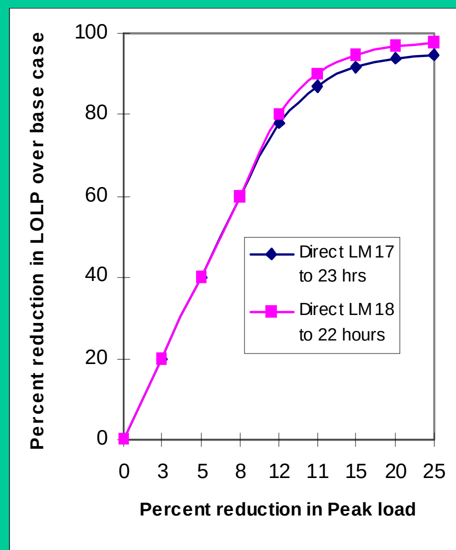
LOAD MANAGEMENT

Load management is the deliberate control or influencing of customer load in order to alter the pattern of electricity use by time-shifting some of the deferrable loads

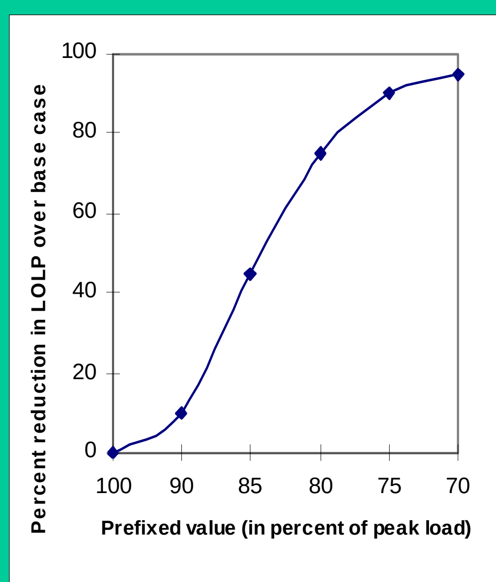
BASIC APPROACHES OF LOAD MANAGEMENT

- ❖ **DIRECT CONTROL**
- ❖ **INDIRECT CONTROL OR CUSTOMER INCENTIVES**
- ❖ **ENERGY STORAGE**

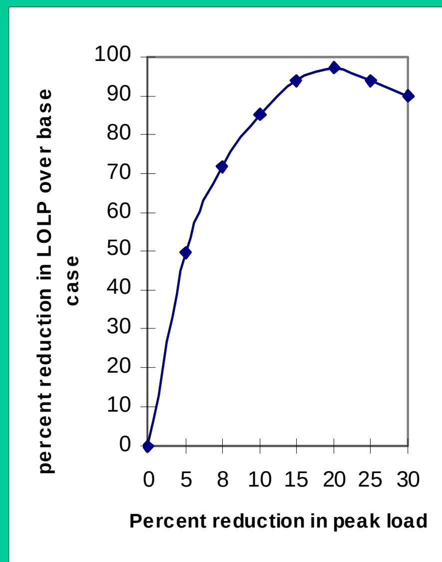
EFFECT OF DIRECT LOAD CONTROL (LOAD REDUCED)



EFFECT OF DIRECT LOAD CONTROL (CONSTANT PEAK)



EFFECT OF INDIRECT LOAD CONTROL



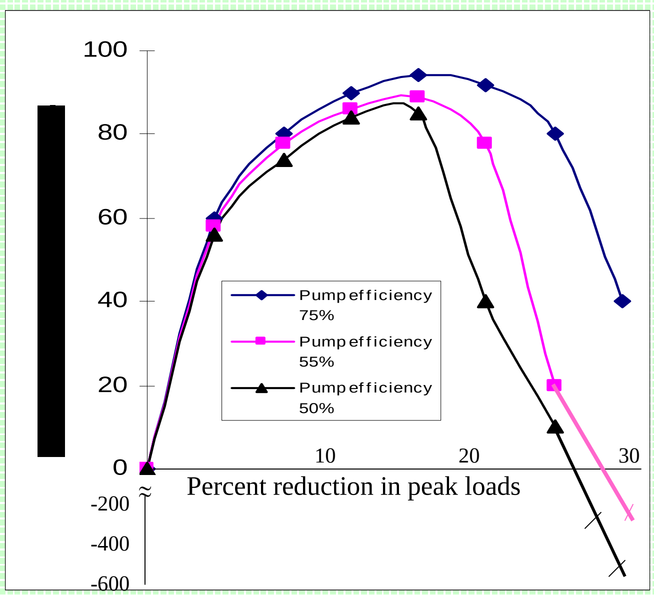
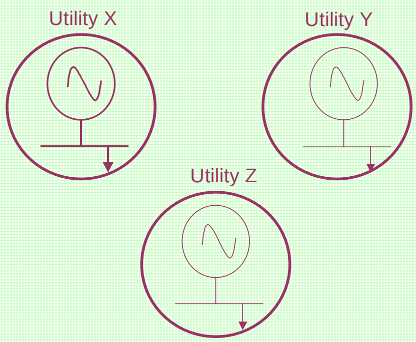


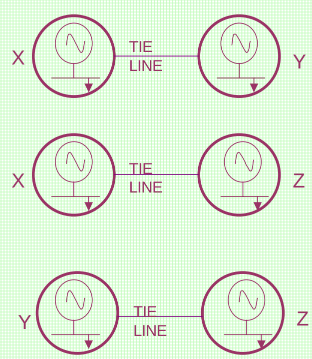
Fig. Impacts of Energy Storage Scheme on Reliability

RELIABILITY BENEFITS OF INTERCONNECTION: BASIC CONCEPT



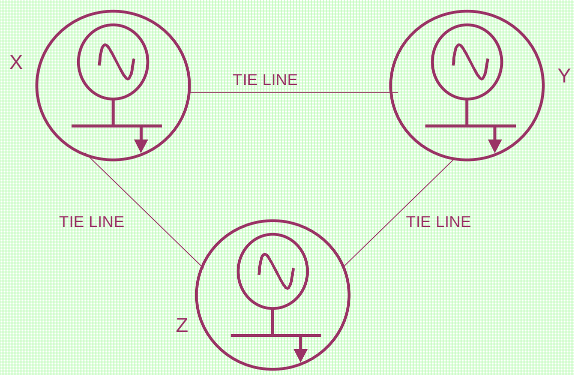
CONFIGURATION 1: ALL UTILITIES ARE ISOLATED

BASIC CONCEPT (cont'd)



CONFIGURATION 2: BILATERAL INTERCONNECTION

BASIC CONCEPT (cont'd)



CONFIGURATION 3: ALL UTILITIES ARE INTERCONNECTED

CONFIGURATION 1: ALL UTILITIES ARE ISOLATED

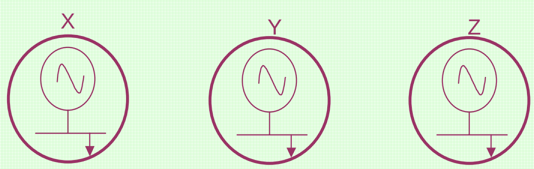


TABLE: GENERATION AND LOAD DATA

Utility	Description of generation		LOAD
	Capacity (MW)	FOR	(MW)
X	20	0.2	10
Y	18	0.10	8
Z	21	0.15	12

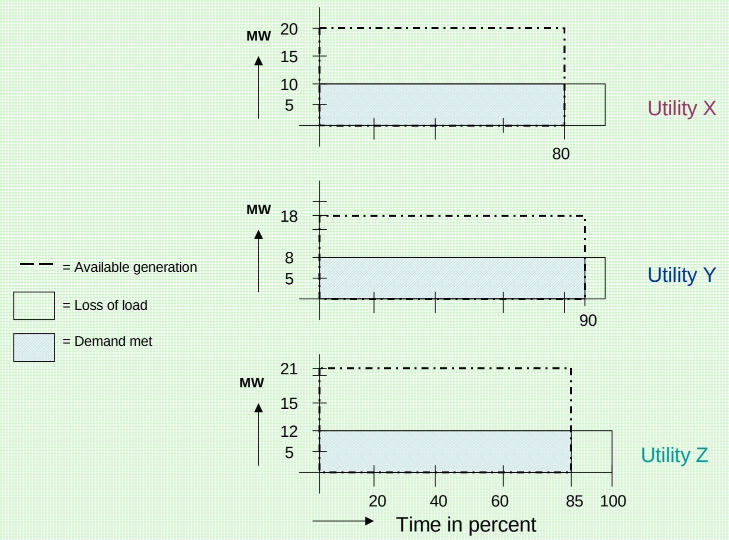


FIG: SCHEMATIC OF AVAILABLE GENERATION AND DEMAND MET

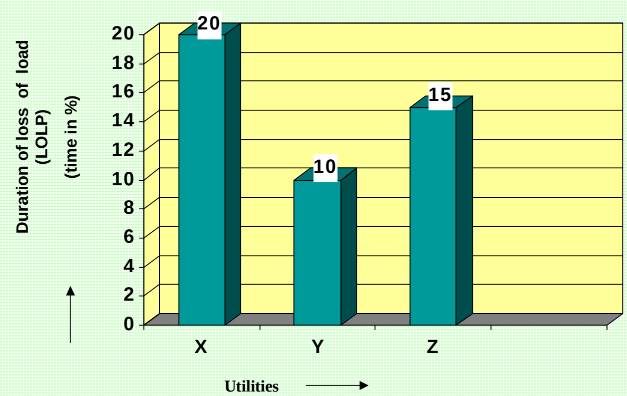


Fig: Duration of loss of load when utilities are isolated

CONFIGARATION 2: BILATERAL INTERCONNETION

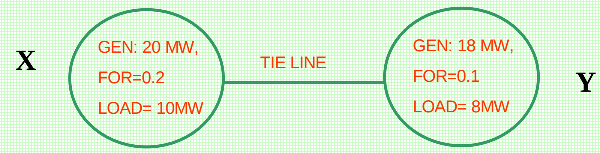


FIG: UTILITYES X AND Y ARE INTERCONNECTED

TABLE: CAPACITY STATE TABLE

STATE OF GENERATION		DURATION (PROBABILITY)
UTILITY X	UTILITY Y	(TIME IN PERCENT)
ON	ON	72
ON	OFF	8
OFF	ON	18
OFF	OFF	2

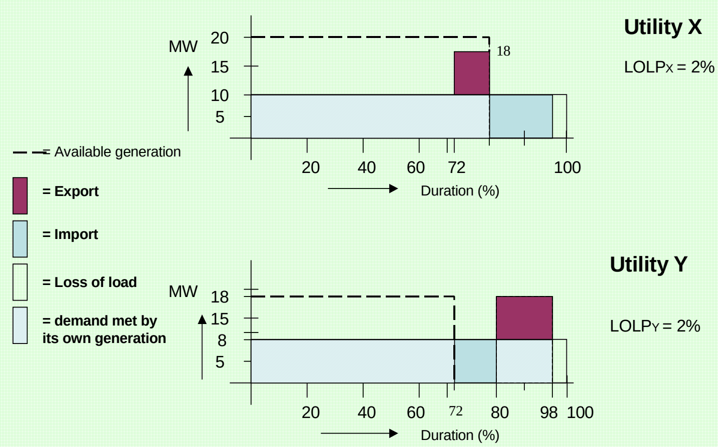


FIG: SCHEMATIC OF AVAILABLE GENERATION AND DEMAND MET
WHEN UTILITIES X AND Y ARE INTERCONNECTED

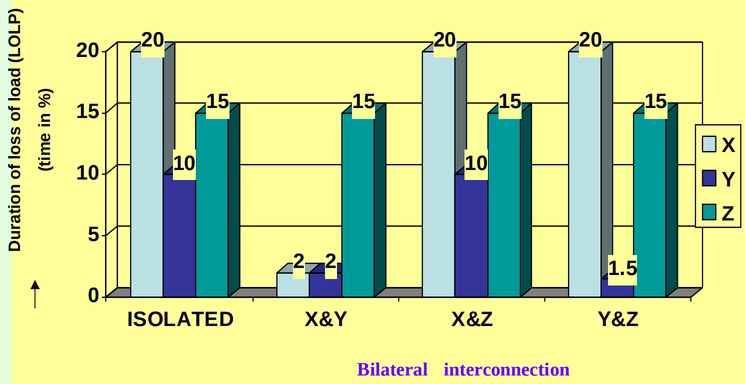


Fig: Comparison of loss of load: isolated utilities and bilateral interconnection

CONFIGARATION 3: MULTILATERAL INTERCONNECTION

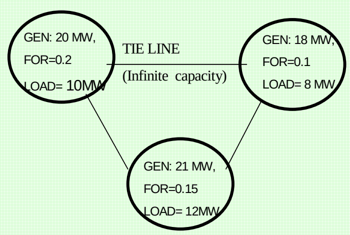


Fig: All three utilities are interconnected

Table: capacity state table

STATE OF GENERATION			DURATION (PROBABILITY)
UTILITY X	UTILITY Y	UTILITY Z	(TIME IN PERCENT)
ON	ON	ON	61.2
ON	OFF	OFF	1.2
ON	OFF	ON	6.8
ON	ON	OFF	10.8
OFF	ON	ON	15.3
OFF	ON	OFF	2.7
OFF	OFF	ON	1.7
OFF	OFF	OFF	0.3

CONFIGARATION 3: MULTILATERAL INTERCONNECTION

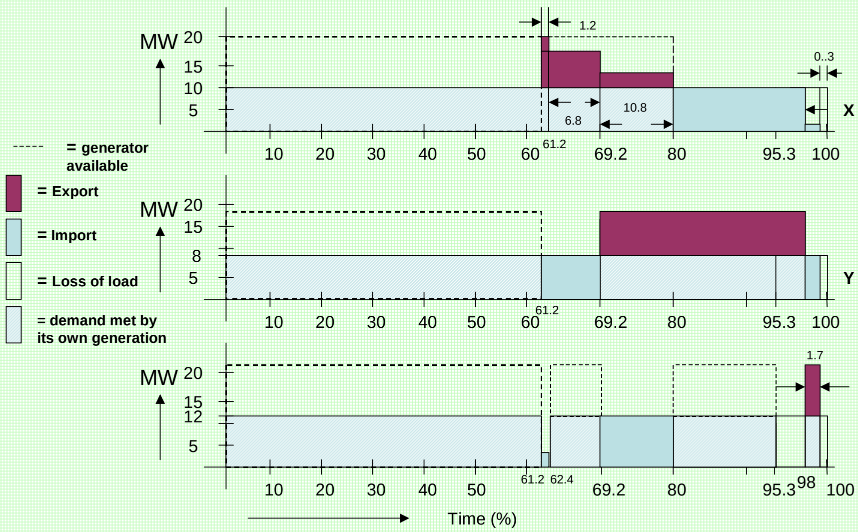


Fig: schematic of available generation and demand met when all utilities are interconnected

Configuration 3: Multilateral interconnection (cont'd)

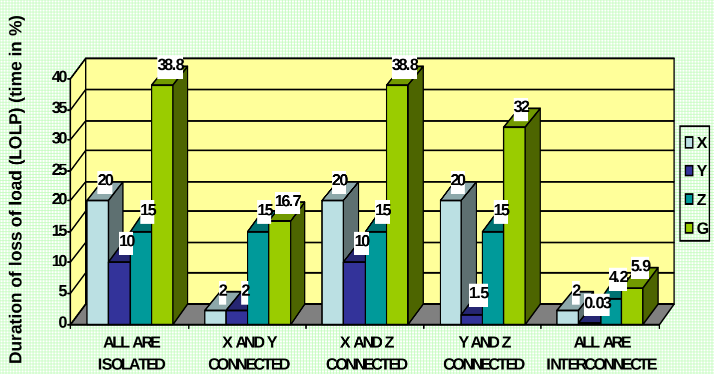
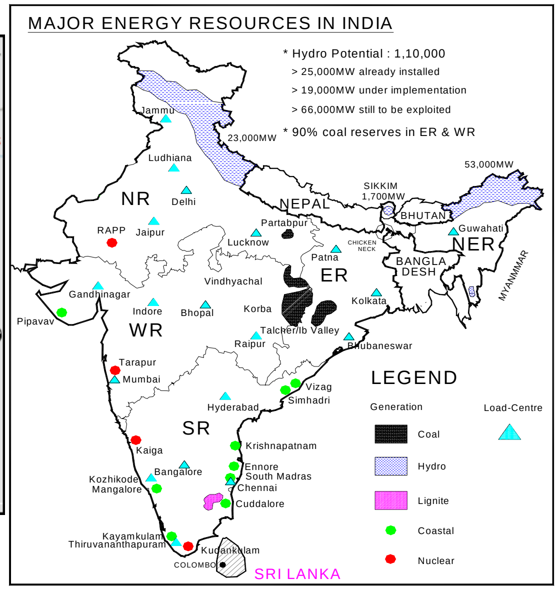


Fig: Comparison of loss of load for different configurations

EXPECTED BENEFITS OF INTERCONNECTION IN SOUTH ASIA

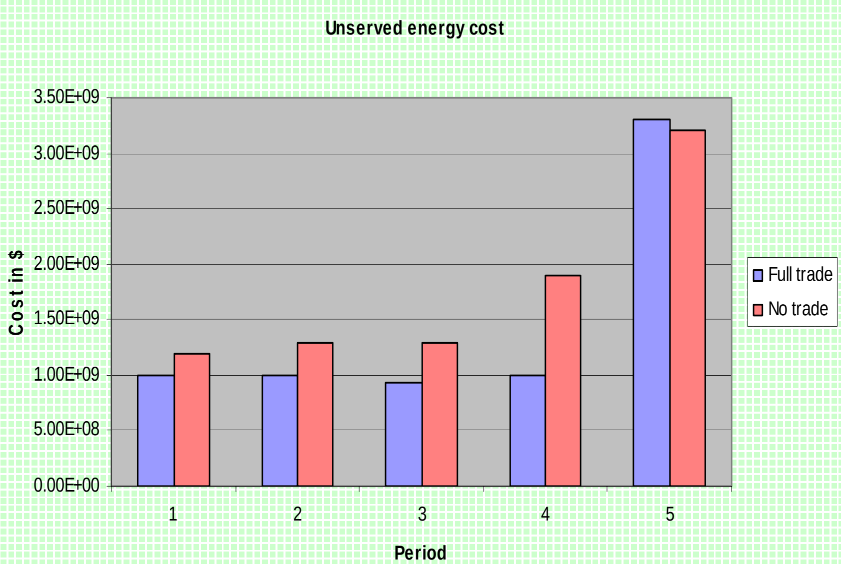


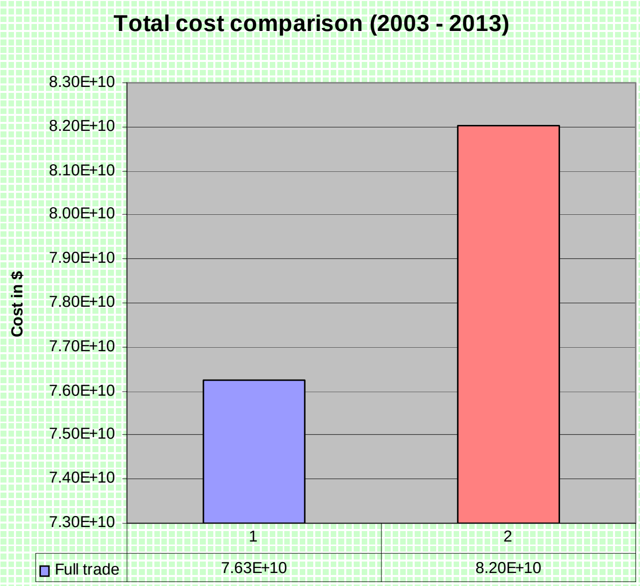
HYDRO ELECTRIC POTENTIAL IN SOUTH ASIA

COUNTRY	POTENTIAL (MW)	ALREADY HARNESSED	
		(MW)	% OF THE POTENTIAL
Bangladesh	555	230	65.71
Bhutan	30000	444	1.48
India	75400	25407	33.7
Nepal	83290	368	0.44
Pakistan	38000	4963	13.06
Sri Lanka	2000	1129	56.45

Initial data

Country	Initial installed capacity (MW)	Initial peak demand (MW)	Load growth (%)
Bangladesh	5230	3200	1.1
Bhutan	4409	100	1.0
India	102800	82000	1.05
Nepal	1126	550	1.08
Pakistan	19500	14000	1.1
Sri Lanka	2829	1600	1.1





CONCLUSIONS

- In expansion planning, factors, like unit size, interconnection, and load management schemes should duly be considered to improve the system reliability or to maintain the standard level of reliability
- Higher unit size should be avoided, in generation expansion, if it does not affect the economy.
- Interconnection with the neighboring utilities improves the system reliability.
- Load management is an option deserves to be considered when other options have problems to be implemented or fail to achieve desired level of reliability.
- Quick repair of faulty devices improves system reliability.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

LOAD CARRYING CAPABILITY OF NEWLY ADDED GENERATING UNIT/UNITS: RELIABILITY ASPECTS

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CONTENTS

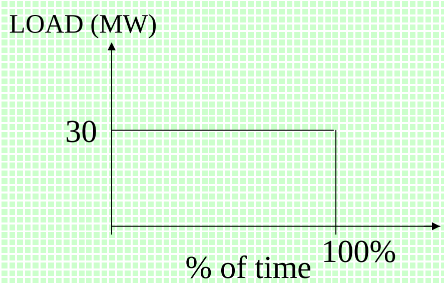
- **EVALUATION TECHNIQUE OF LOAD CARRYING CAPABILITY (LCC) OF A GENERATING UNIT**
- **IMPACTS OF FOR ON LCC**
- **CONCLUSIONS**

ILLUSTRATION OF EVALUATION PROCEDURE OF LOAD CARRYING CAPABILITY (LCC) OF A GENERATING UNIT

GENERATION MODEL

Capacity	FOR
20	0.1
30	0.2

LOAD MODEL



CAPACITY OUTAGE TABLE

Capacity Out (MW)	Available Capacity	Exact Probability	Cumulative Prob.
0	50	0.72	1.0
20	30	0.08	0.28
30	20	0.18	0.20
50	0	0.02	0.02

LOLP = Pr. (AC < PK) = 0.2

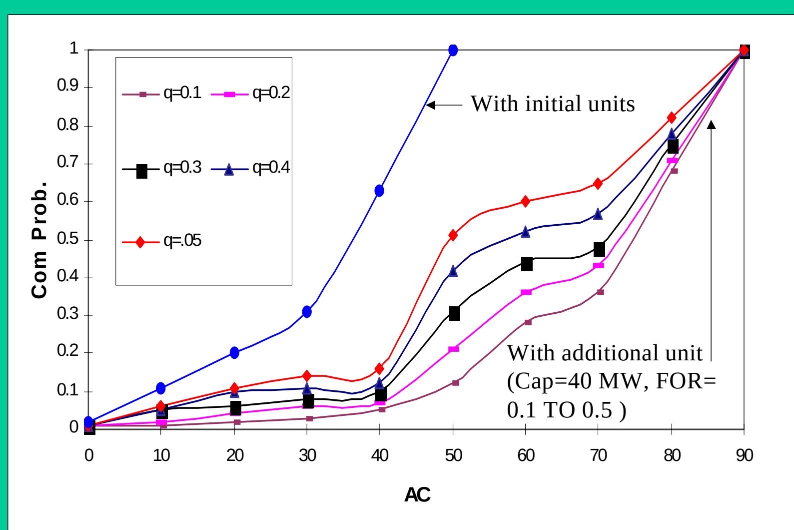
CAPACITY OUTAGE TABLE (WITH AN ADDITIONAL UNIT OF 40 MW AND FOR OF 0.1)

Capacity on outage (MW)	Available Capacity	Probability	Cumul. Prob.
0	90	0.648	1.0
20	70	0.072	0.352
30	60	0.162	0.28
40	50	0.072	0.118
50	40	0.018	0.046
60	30	0.008	0.028
70	20	0.018	0.02
90	0.0	0.002	0.002

FOR A PEAK OF 30 MW, LOLP = 0.02

FOR LOLP = 0.2 60 < PEAK < 50

EFFECT OF FOR ON LCC



IMPACTS OF FORS ON LCC

FOR	LCC (MW)
0.5	11.5
0.4	12
0.3	14
0.2	19
0.1	25.5

CHANGES IN LCC IN A REALISTIC SYSTEM

IC = 10,100 MW

Highest unit capacities 300 MW and 500 MW

LOLP = 0.1 day/year

Changing FOR of 300 MW and 500 MW only

FOR (%)	Peak load carrying capacity (MW)	Reduction in peak carrying capacity (MW)
4	9006	--
5	8895	111
6	8793	213
7	8693	313
8	8602	404
9	8513	493
10	8427	579
11	8345	661
12	8267	739
13	8191	815

❖**The above table shows the change in LCC for FOR values from 4% to 13%.**

❖ **The decrease in LCC is 815 MW.**

❖**If the forecasted peak is 9006 MW and the FORs of large units are 13% then the system would have to install approximately 815 MW additional capacity to maintain LOLP (a reliability level of) 0.1 day/year**

CONCLUSIONS

- LCC is an useful measure to system planners to see the relative impact of new units in satisfying system load growth
- System with units of higher FORs requires higher installed capacity to meet the system demand (peak).

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

EVALUATION TECHNIQUES OF RELIABILITY LEVEL OF A SINGLE AREA UTILITY

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SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

- **DIFFERENT RELIABILITY INDICES**
- **DESCRIPTION OF DIFFERENT STEPS OF RECURSIVE METHOD**
- **DEFFERENT TECHNIQUES OF DEVELOPING CAPACITY OUTAGE TABLE**
- **EVALUATION OF LOLP**
- **SEGMENTATION METHOD AND ITS ILLUSTRATION**

RELIABILITY INDICES

- Loss of Load Probability (LOLP)
- Loss of Energy Probability (LOEP)
- Frequency and Duration (FAD)
- Monte Carlo Simulation (MCS)

METHODOLOGIES

- Recursive (Booth –Baleriaux Technique) Method
- Cumulant Method
- Segmentation Method

DIFFERENT STEPS OF RECURSIVE METHOD

- **DEVELOP A CAPACITY OUTAGE TABLE OF THE GENERATING SYSTEM USING EITHER THE OUTAGE CAPACITY BUILDING ALGORITHEM OR BY USING THE RECURSIVE FORMULA.**
- **INSERT THE AVAILABLE CAPACITY COLUMN OBTAINED FROM CAPACITY OUTAGED STATE AND THE INSTALLED CAPACITY .**
- **ALSO INSERT A CUMULATIVE PROBABILITY COLUMN USING THE EXACT PROBABILITY VALUES (IF RECURSIVE FORMULA IS NOT USED).**
- **FOR EACH LOAD LEVEL FIND THE LOLP CONSIDERING THAT LOLP = PROBABILITY {AVAILABLE CAPACITY < LOAD} FROM THE CUMULATIVE PROBABILITY COLUMN**

- **MULTIPLY EACH LOLP VALUE OBTAINED FOR A GIVEN LOAD LEVEL BY THE PROBABILITY OF THE OCCURRENCE OF THAT LOAD**
- **SUM THE PRODUCT OF LOLP CORRESPONDING TO EACH LOAD LEVEL AND THE PROBABILITY OF OCCURRENCE OF THAT LOAD TO GET THE FINAL VALUE OF LOLP**

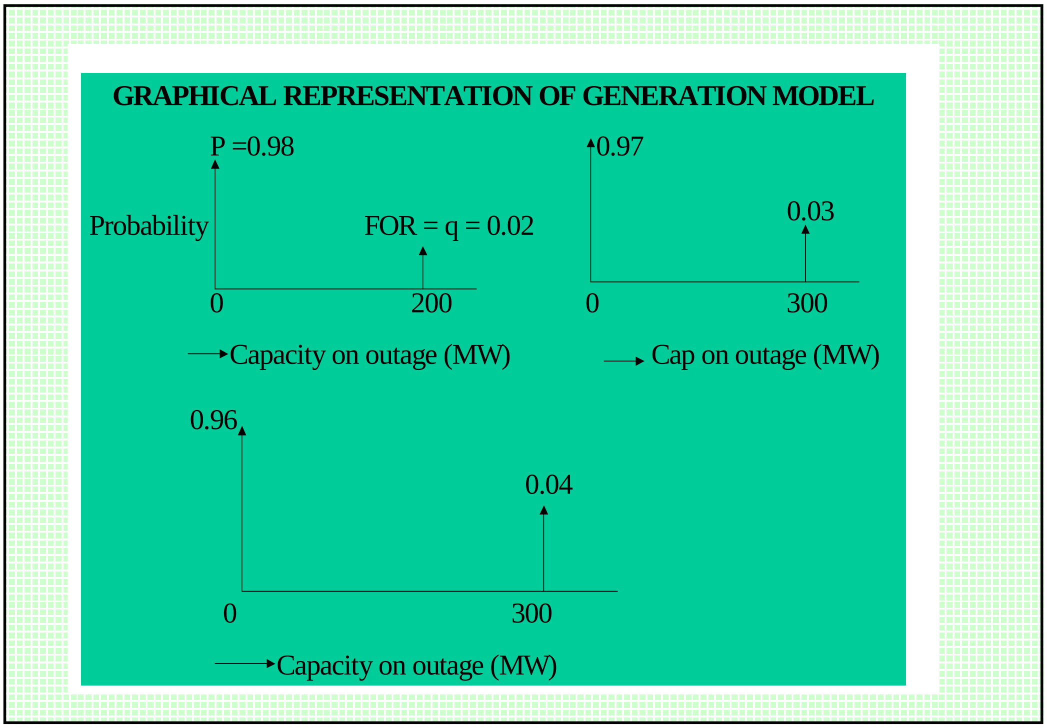
EXAMPLE CLARIFYING METHODOLOGY

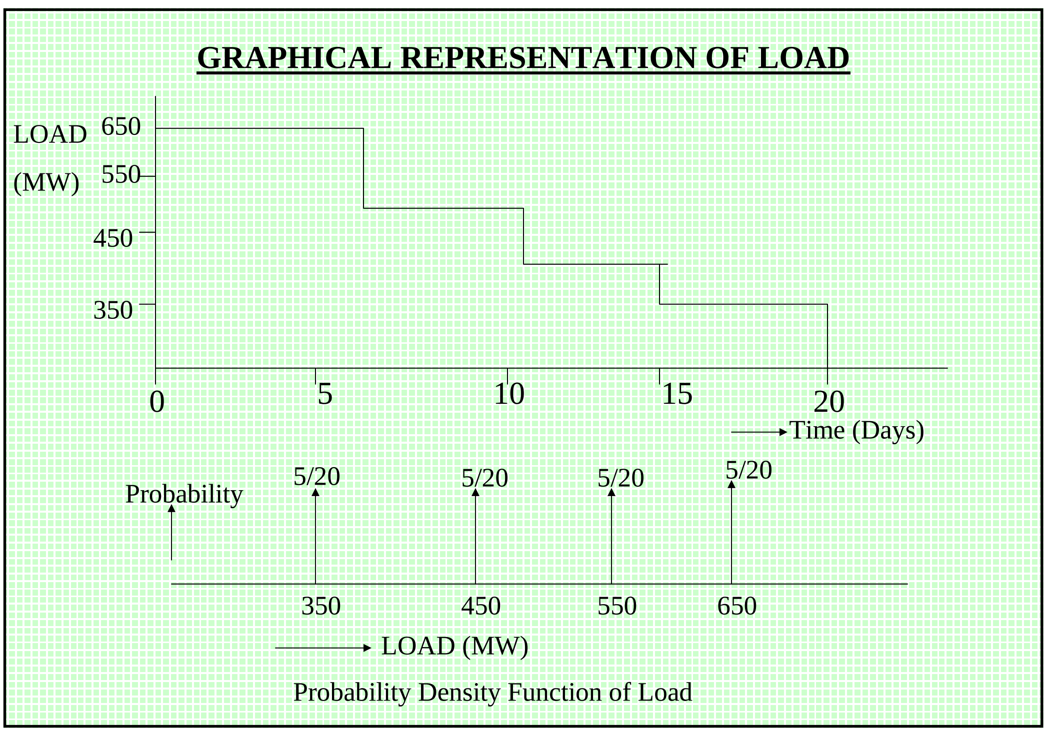
GENERATION MODEL

Capacity (MW)	FOR
200	0.02
300	0.03
400	0.04

LOAD MODEL

Load level (MW)	No. of occurrence (days)
650	5
550	5
450	5
350	5


GRAPHICAL REPRESENTATION OF GENERATION MODEL
P =0.98
Probability
FOR = q = 0.02
0
200
Capacity on outage (MW)
0.97
0.03
0
300
Cap on outage (MW)
0.96
0.04
0
300
Capacity on outage (MW)

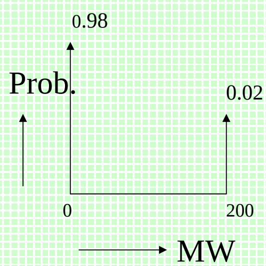

GRAPHICAL REPRESENTATION OF LOAD
LOAD
(MW)
650
550
450
350
0
5
10
15
20
Time (Days)
Probability
5/20
5/20
5/20
5/20
350
450
550
650
LOAD (MW)
Probability Density Function of Load

CAPACITY OUTAGE TABLE

(State Enumeration Technique)

STATES OF UNITS				
UNIT # 1	**UNIT # 2**	**UNIT # 3**	**CAPACITY ON OUTAGE (MW)**	**PROBABILITY OF OCCURRENCE**
ON	ON	ON	0	0.98 x .97 x .96 = 0.912576
DOWN	ON	ON	200	0.018624
ON	DOWN	ON	300	0.028224
ON	ON	DOWN	400	0.038024
DOWN	DOWN	ON	500	0.000576
DOWN	ON	DOWN	600	0.000776
ON	DOWN	DOWN	700	0.001176
DOWN	DOWN	DOWN	900	0.000024

CAPACITY OUTAGE TABLE BUILDING ALGORITHM

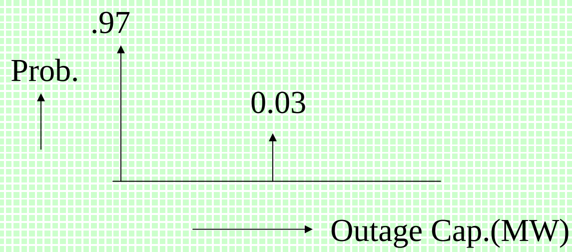


This density function can be expressed in the form of a Capacity Outage Table

Table 1

Capacity on outage (MW)	**Probability**
0	0.98
200	0.02

To incorporate 2nd unit



First , Considering 2nd. Unit in Service

Table – 2

Capacity on Outage (MW)	Probability
0 + 0 = 0	0.98 x .97 = 0.9506
200 + 0 = 200	0.02 x .97 = 0.0194

Next, Considering 2nd Unit (300 MW) out of Service

Table - 3

Capacity on outage (MW)	Probability
0 + 300 = 300	0.98 x .03 = .0394
200 + 300 = 500	0.02 x .03 = .0006

Combining Tables 2 and 3, one gets

Table – 4

Capacity on outage (MW)	Probability
0	0.9506
200	0.0194
300	0.0294
500	0.0006

To in corporate the 3rd Unit (400 MW, FOR = 0.04)

Follow the above procedure

Table – 5 (Considering 400 MW Unit in service)

Capacity on outage (MW)	**Probability**
0 + 0 = 0	0.9506 x .96 = 0.912576
200 + 0 = 200	0.0194 x .96 = 0.018624
300 + 0 = 300	0.0294 x .96 = 0.028224
500 + 0 = 500	0.0006 x .96 = 0.000576

Table – 6 (Considering 400 MW Unit out of service)

Capacity on outage (MW)	**Probability**
0 + 400 = 400	0.9506 x .04 = 0.038024
200 + 400 = 600	0.0194 x .04 = 0.000776
300 + 400 = 700	0.0294 x .04 = 0.001176
500 + 400 = 900	0.0006 x .04 = 0.000024

Combining Tables 5 and 6 and reordering capacity states

Table – 7

Capacity on outage (MW)	**Probability**
0	0.912576
200	0.018624
300	0.028224
400	0.038024
500	0.000576
600	0.000776
700	0.001176
900	0.000024

Introducing available capacity and cumulative probability columns Table – 7 becomes

TABLE 8

Capacity on Outage (MW)	**Available capacity (MW)**	**Exact Probability**	**Commutative Probability**
0	900	0.912576	1.0
200	700	0.018624	0.087424
300	600	0.028224	0.068800
400	500	0.038024	0.040576
500	400	0.000576	0.002552
600	300	0.000776	0.001976
700	200	0.001176	0.001200
900	00	0.000024	0.000024

The above table can also be obtained using a recursive formula

$P(X) = (1 - q)\, P'(X) + q\, P'(X' - c)$

Where,

$$P'(X) = \begin{Bmatrix} 1 & if & \times & \leq & 0 \\ 0 & other & & wise \end{Bmatrix}$$

P'(X) = Cumulative probability of X MW or greater before the unit of C MW is added

P(X) = Cumulative probability of X MW or greater after the unit of C MW is added

EVALUATION OF LOLP

Load Level	Probability of Occurrence	Reserve available Capacity (MW)	LOLP (For individual load)
350	5/20	550	0.001976 x $\frac{5}{20}$
450	5/20	450	0.002552 x $\frac{5}{20}$
550	5/20	350	0.040576 x $\frac{5}{20}$
650	5/20	250	0.057424 x $\frac{5}{20}$

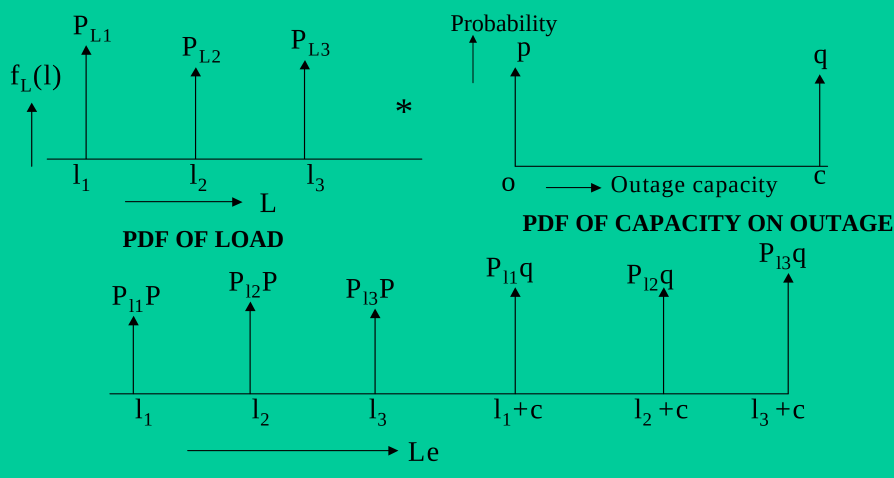
LOLP = 0.028476

SEGMENT METHOD

Concept behind segmentation method

For binary state model of a generating unit the convolution of the PDF of the outage capacity of a generating unit with the PDF load can be expressed as

$$f_{Le}(le) = f_L(l)p + f_L(Le - C)q$$



PDF AFTER CONVOLUTION

DIFFERENT STEPS OF SEGMENTATION METHOD

- Obtain the PDF of load by sampling the chronological historical or forecasted load.
- Construct segments by dividing demand axis. The segment size is equal to the highest common factor of the generating unit capacities.
- Obtain the distribution of segment by translating the PDF of load into the PDF of segment. This is done by simply attaching a probability to a segment, which is equal to the sum of probabilities of the load impulses lying in the range of that segment.
- Convolve the PDF of each generating unit one by one with the PDF of segments. The convolution procedure requires.
- Multiplication of the distribution of segments by the availability of the unit.
- Shifting the original distribution of segments towards right by an amount equal to the capacity of the unit being convolved.
- Multiplication of the shifted distribution by the unavailability of the unit.
- Addition of the above two products to get the final distribution after convolution.

After convolving all the units in the system LOLP is evaluated. LOLP is equal to the probability value of the last segment in the final distribution.

ILLUSTRATION OF METHODOLOGY

[?]c = Segment Size = Highest common factor of (200, 300, 400) =100

N = Number of segments = $\frac{200+300+400}{100}+1=10$

Installed Capacity

MW

Shift / MW	0	100		300			600			900	Multiplier
				0.25	0.25	0.25	0.25				x 0.98
Shift = 200						0.25	0.25	0.25	0.25		x 0.02
				0.245	0.245	0.25	0.25	0.005	0.005		x 0.97
300							.245	.245	.25	.25+.005 +.005	x .03

MW

	0	100		300			600			900	Multiplier
				.23765	.23765	.2425	.24985	.0122	.01235	.0078	x .96
400 MW								.23765	.23765	0.5247	x .04
					0.228144	0.2328	0.239856	0.021218	0.021362	0.028476	

LOLP = 0.028476

CONCLUSIONS

- **RECURSIVE AND SEGMENTATION METHODS FOR THE EVALUATION OF RELIABILITY INDEX, LOLP, FOR A SINGLE AREA SYSTEM ARE ILLUSTRATED THROUGH EXAMPLE**
- **SEGMENTATION METHOD IS CONCEPTUALY STRAIGHT FORWARD**
- **SEGMENTATION METHOD IS ALSO COMPUTATIONALY SIMPLE**

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

EVALUATION TECHNIQUES OF RELIABILITY LEVEL OF INTERCONNECTED UTILITIES

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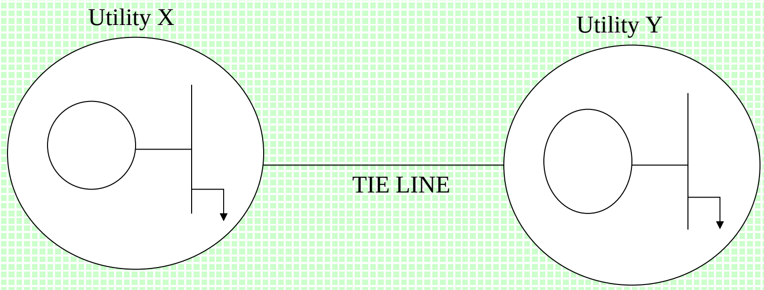
SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS



CAPACITY TRANSCTION BETWEEN THE INTERCONNECTED SYSTEMS DEPENDS ON

- **TIE LINE CAPACITY**
- **DEMAND OF THE EXPORTING SYSTEM**
- **DEMAND OF THE IMPORTING SYSTEM**
- **AVAILABLE GENERATING CAPACITY OF THE EXPORTING SYSTEM**

THE INCORPORATION OF THE ABOVE CONSTRANTS AND KEEPING THE INDENTITY OF EACH INDIVIDUAL UTILITY MAKE THE EVALUATION PROCEDURE OF INTERCONNECTED SYSTEM DIFFERENT FROM THAT OF THE SINGLE AREA SYSTEM

DIFFERENT STEPS OF SEGMENTATION METHOD FOR THE EVALUATION OF RELIABILITY INDICES OF TWO NTERCONNECTED SYSTEM IN CASE OF UNCORRELATED (INDEPENDENT) LOAD

- Develop the probability density function (PDF) of load .
- Construct segments of equal size by dividing the demand axis. The segment size is the highest common factor of the generating units and tie line capacities. The total number of segments is equal to the installed generating unit capacity divided by the segment size plus one.
- Obtain the distribution of segments by translating the PDF of load into that of segment . The probability of a segment is equal to the sum of the probabilities of the load impulses lying in the range of the segment.
- Convolve the PDFs of all generating units of a system with that of the segment one by one. To do so,
  - Multiply the distribution of segments by the availability of the unit, i.e. (1 –FOR), being convolved.

- Shift the original distribution of segments towards right by an amount equal to the capacity of the unit being convolved.
- Multiply the shifted distribution by the FOR of the unit.
- Obtain the distribution of segments after convolution by adding the above two product.

- Form the joint PDF of segments (Venn diagram) by using the PDF of segments of each system obtained after convolving all the units in that system.
- Integrate the different zones of Venn diagram to obtain the different reliability indices.

EXAMPLE FOR CLARIFICATION (INDEPENDENT LOAD)

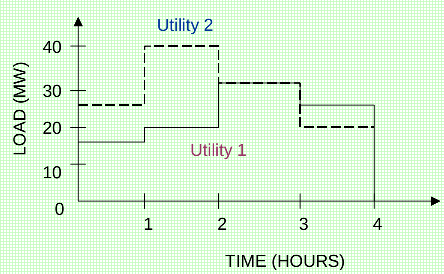
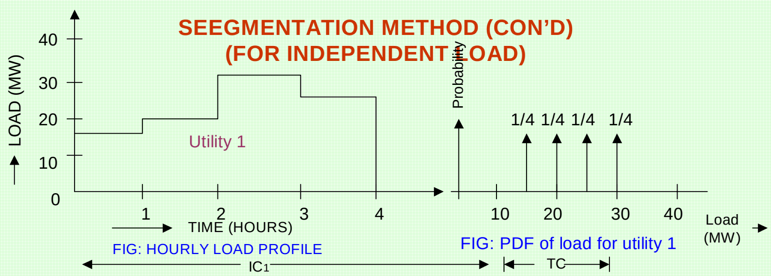


FIG: HOURLY LOAD PROFILE

Table: Generating system description

Utility 1			Utility 2		
No of units	Capacity (MW)	FOR	No of units	Capacity (MW)	FOR
2	10	0.2	2	15	0.1
1	30	0.1	1	25	0.3

SEEGMENTATION METHOD (CON'D)
(FOR INDEPENDENT LOAD)



10		20		30		40		50		60	
1	1	1	1								X.8 =(1-FOR)
SHIFT 10 MW		1	1	1	1						X.2=FOR
.8	.8	1	1	.2	.2						X.8
10 MW		.8	.8	1	1	.2	.2				X.2
.64	.64	.96	.96	.36	.36	.04	.04				X.9
30 MW						.64	.64	.96	.96	.8	X.1
.576	.576	.864	.864	.324	.324	.1	.1	.096	.096	.08	

Fig: schematic of convolution procedure of system 1 (all numbers in the boxes to be divided by 4)

SEGMENTATION METHOD (FOR INDEPENDENT LOAD) (CON'D)

	IC1							TC		
0.144	0.144	0.216	0.216	0.081	0.81	0.025	0.025	0.024	0.024	0.02

	10		20		30		40		50		60
0.14175 (15)	0.02041	0.02041	0.020412	0.004536	0.024948	0.013284	0.009	0.01354	0.002196	0.010692	0.004572
0.14175	0.02041	0.02041	0.020412	0.004536	0.024948	0.013284	0.009	0.01354	0.002196	0.010692	0.004572
0.14175 (25)	0.03062	0.03062	0.030618	0.006804	0.037422	0.019926	0.0135	0.0203	0.003294	0.016038	0.006858
0.00315	0.03062	0.03062	0.030618	0.006804	0.037422	0.019926	0.0135	0.0203	0.003294	0.016038	0.006858
0.17325 (35)	0.01148	0.01148	0.011482	0.002552	0.014033	0.007472	0.005063	0.00761	0.001235	0.006014	0.002572
0.09225	0.01148	0.01148	0.011482	0.002552	0.014033	0.007472	0.005063	0.00761	0.001235	0.006014	0.002572
0.0625 (45)	0.00354	0.00354	0.003544	0.000788	0.004331	0.002306	0.001563	0.00235	0.000381	0.001856	0.000794
0.094	0.00354	0.00354	0.003544	0.000788	0.004331	0.002306	0.001563	0.00235	0.000381	0.001856	0.000794
0.01525 (55)	0.0034	0.0034	0.003402	0.000756	0.004158	0.002214	0.0015	0.00226	0.000366	0.001782	0.000762
0.07424	0.0034	0.0034	0.003402	0.000756	0.004158	0.002214	0.0015	0.00226	0.000366	0.001782	0.000762
0.03175 (65)	0.00284	0.00284	0.002835	0.00063	0.003465	0.001845	0.00125	0.00188	0.000305	0.001485	0.000635

FIG: SCHEMATIC REPRESENTATION OF JOINT PROBABILITIES (VENN DIAGRAM) (ALL NUMBERS INSIDE THE BOX BE DIVIDED BY 4X4 AND ALL PROBABILITY VALUES OF THE VECTORS BE DIVIDED BY 4)

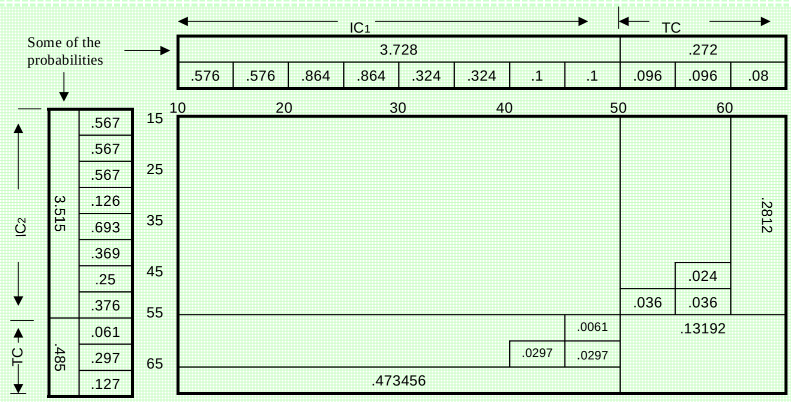


Fig: schematic representation of joint probabilities (all numbers inside the joint probability matrix to be divided by 4x4 and all the probability values of the vectors outside the matrix to be divided by four)

$LOLP_1 = 0.272/4 = 0.068$

$LOLP_2 = 0.485/4 = 0.12125$

$$LOLP_{1/2} = \frac{0.13192 + 0.036 + 0.036 + 0.024 + 0.2812}{4X4} = 0.031832$$

$$LOLP_{1/2} = \frac{0.13192 + 0.0061 + 0.0297 + 0.0297 + 0.473456}{4X4} = 0.0419297$$

$LOLP_G = (.031832+.0419297)-0.13192=0.065516$

DIFFERENT STEPS OF SEGMENTATION METHOD FOR THE EVALUATION OF RELIABILITY INDICES OF TWO INTERCONNECTED SYSTEM IN CASE OF CORRELATED DEMAND.

- Develop the joint PDF of load
- Construct two dimensional segments by dividing X and Y axes forming segments of square size. That is all four sides of a segment are equal in size and each side is equal to the highest common factor of generating unit capacities of both systems and the tie line capacity. The total number of divisions of an axis is equal to the installed capacity of a system to which the axis is assigned plus tie line capacity divided by the segment size plus one.
- Obtain the PDF of segment by translating the joint PDF of load. The probability of a segment is equal to the sum of the probabilities of the load impulses lying in the range of that segment.

❖Shift the original PDF, i.e, before multiplying by (1-q) in the above step.The amount of shift is equal to the capacity of the unit being convolved. The direction of shift depends on the system to which the convolving unit belongs to.If the unit belongs to a system which is assigned to x-axis, the direction of shift will be towards x-axis, otherwise the shift will be towards Y- axis.

- ❖ Multiply the shifted distribution by the unavailability of the unit, q
- ❖ Obtain the distribution of segments after convolution by adding the above two products.

❖ Integrate the different zones of the probability mass, evolved after convolving all the units of both systems, to obtain the different probability indices.

EXAMPLE FOR ILLUSTRATION

SEGMENTATION METHOD FOR CORRELATED LOAD

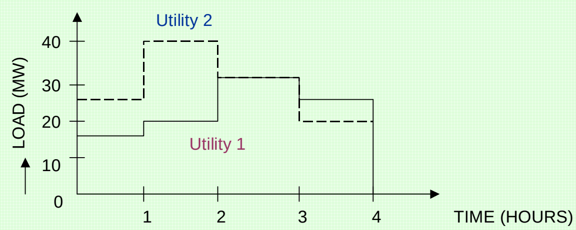


FIG: HOURLY LOAD PROFILE OF TWO UTILITIES

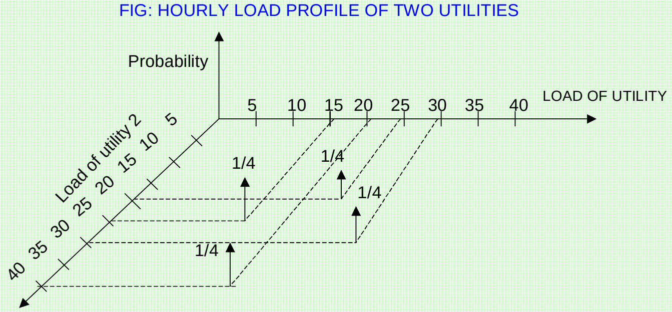


Fig: joint PDF OF loads of two utilities

SEGMENTATION METHOD FOR CORRELATED LOAD (CONT'D)

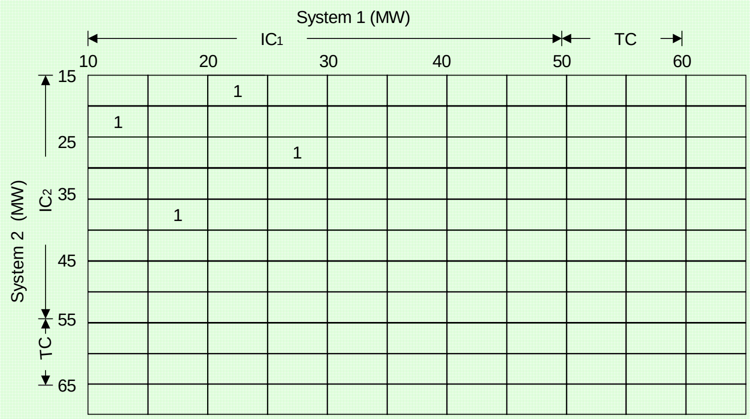


Fig: joint probability matrix for systems with correlated load (all numbers in the boxes to be divided by 4).

PROCESS OF CONVOLUTION

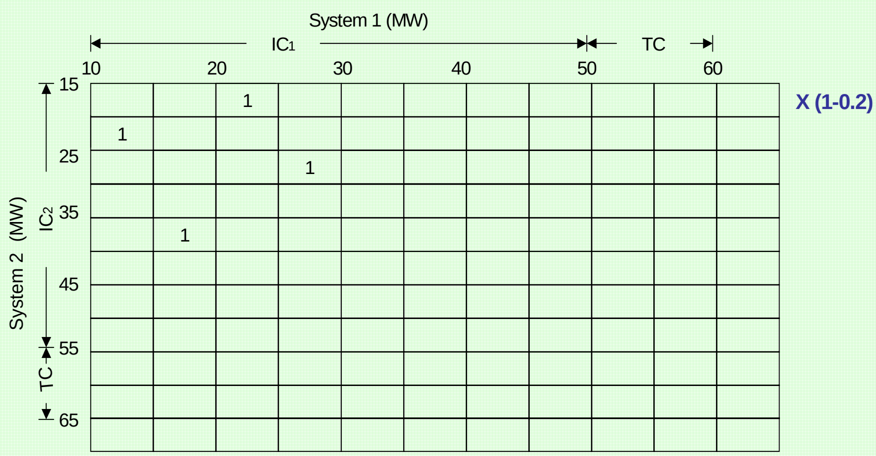


Fig: Unshifted distribution of segment multiplied by the availability of the unit (All numbers in the boxes to be divided by 4)

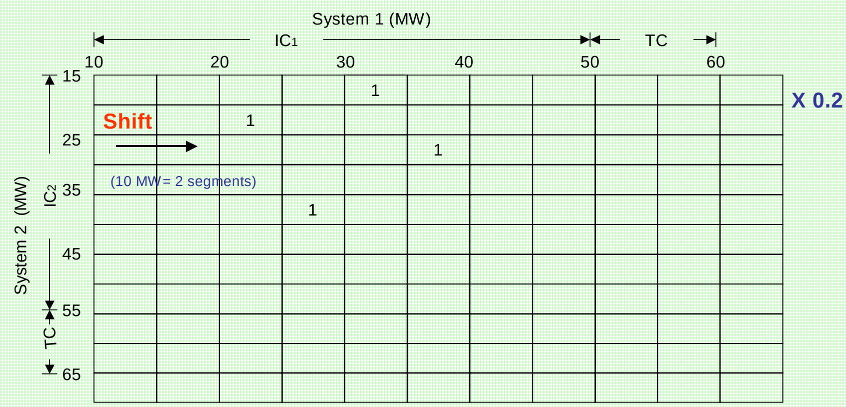


Fig: Shifted distribution of segments (Multiplied by FOR) (all numbers in the boxes to be divided by 4)

SEGMENTATION METHOD FOR CORRELATED LOAD (CONT'D)

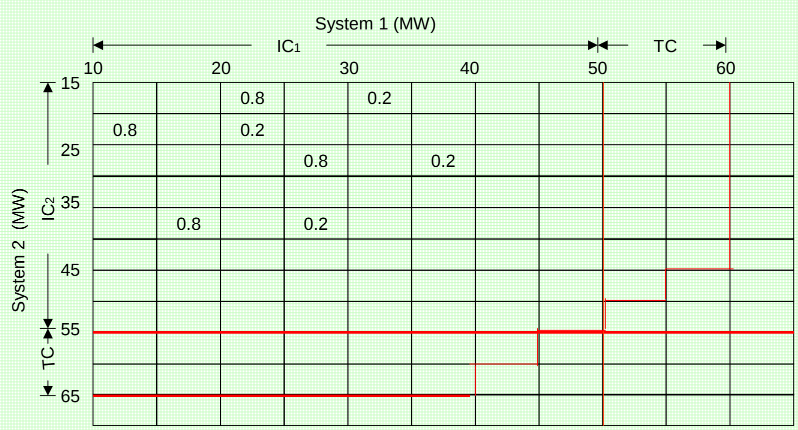


Fig: Joint probability Matrix after convolving one 10 MW unit of system 1 (all numbers in the boxes to be divided by 4).

SEGMENTATION METHOD FOR CORRELATED LOAD (CONT'D)

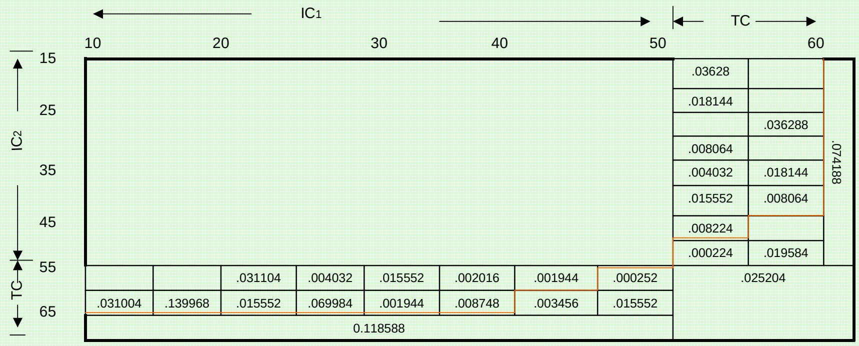


Fig: Joint probability matrix after convolving all the units of two utilities (all numbers in the boxes to be divided by 4)

$LOLP_1$ = (0.03628+0.018144+----------+0.025204+0.074188)/ 4 = 0.068

$LOLP_2$ = (0.031104+---------------+0.000252+0.118588+0.025204) / 4 = 0.12125

$LOLP_{1/2}$ = (0.025204+0.074188+0.000224+0.019584) /4 =0.0298

$LOLP_{2/1}$ = (0.025024+0.118588+0.003456+0.015552+0.000252) /4 = 0.040763

$LOLP_G$ = (0.0298+.040763)-.0252044 =0.064262

CONCLUSIONS

- ❖ CONSTRAINTS OF CAPACITY TRANSACTION MAKE THE EVALUATION OF INTERCONNECTED SYSTEM DIFFERENT FROM THAT OF A SINGLE AREA SYSTEM
- ❖ AMONG DIFFERENT TECHNIQUES OF EVALUATION SEGMENTATION METHOD IS EASY TO IMPLEMENT

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

CAPACITY SAVINGS THROUGH INTERCONNECTION AND OPTIMAL TIE LINE CAPACITIES

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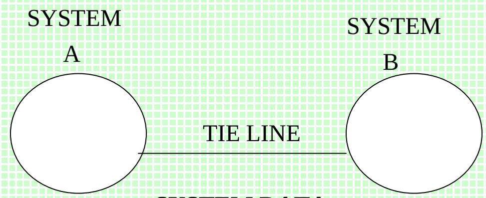
SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

- **EVALUATION OF THE EQUIVALENT GENERATING UNIT CAPACITY**
- **OPTIMAL TIE LINE CAPACITY EVALUATION THROUGH CASE STUDIES**
- **IEEE RELIABILITY TEST SYSTEM**
- **SMALL SYSTEM**

ILLUSTRATION OF THE EVALUATION PROCEDURE OF A GENERATING UNIT CAPACITY EQUUIVALENT TO THE TIE LINE CAPACITY



SYSTEM DATA

SYSTEM	NUMBER OF UNITS	CAPACITY (MW)	FOR	INSTALLED CAPACITY (MW)	PEAK LOAD (MW)
A	5 1	10 25	0.02 0.02	75	50
B	4 1	10 20	0.02 0.02	60	40
TIE LINE CAPACITY	1	10	0		

CAPACITY OUTAGE TABLE OF SYSTEM A

Cap.out (MW)	Individual probability	Cum.probability
0	0.88584238	1.00000000
10	0.09039207	0.11415762
20	0.00368947	0.02376555
25	0.01807841	0.02007608
30	0.00007530	0.00199767
35	0.00184474	0.00192237
40	0.00000077	0.00007763
45	0.00007530	0.00007686
50	0.00000000	0.00000156
55	0.00000154	0.00000156
65	0.00000002	0.00000002
75	0.00000000	0.00000000

CAPACITY OUTAGE TABLE OF SYSTEM B

Cap.out (MW)	Individual Prob.	Cum. prob.
0	0.90392080	1.00000000
10	0.07378945	0.09607920
20	0.02070622	0.02228975
30	0.00153664	0.00158353
40	0.00004626	0.00004689
50	0.00000063	0.00000063
60	0.00000000	0.00000000

JOINT PROBABILITY DENSITY FUNCTION OF TWO INT. SYSTEMS

$R_B = 20$

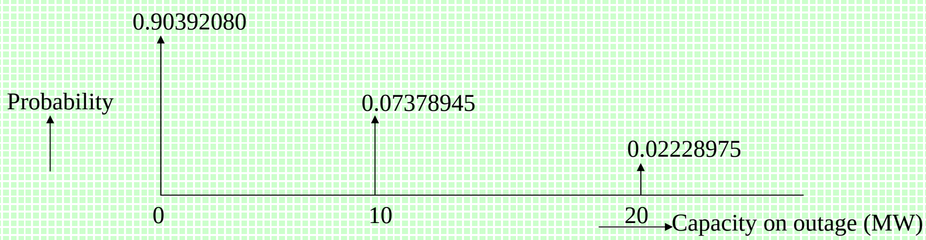
$R_A = 25$

		0	10	20	30	40	50	60
		0.9039	0.0737	0.0207	0.0015	0.0000	0.0000	0.0000
0	0.8858	0.0000	0.0582	0.0045	0.0013	0.0000	0.0000	0.000
10	0.0903	0.0000	0.0098	0.0168	0.0001	0.0000	0.0000	0.0000
20	0.0036	0.0099	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000
25	0.0180	0.0146	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000
30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
35	0.0018	0.0016	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
40	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
45	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
55	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
65	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
75	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

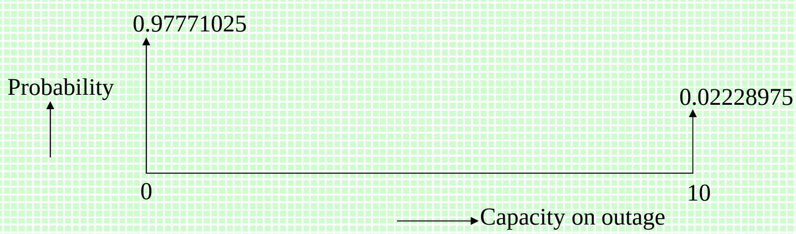
(VENN DIAGRAM) $LOLP_{A/B} = 0.00012042$

PROBABILITY TABLE OF ASSISTANCE FROM SYSTEM B

Capacity outage of system B (MW)	Reserve of System B (MW)	Expected Assistance from System B to System A (MW)	Probability
0	20	20	0.90392080
10	10	10	0.07378945
20	0	0	0.02228975



Probabilistic model of an equivalent assistance unit (From system B to System A)



Probabilistic model of equivalent assistance unit incorporating tie line constraint

MODIFIED CAPACITY OUTAGE TABLE OF SYSTEM A INCLUDING EQUIVALENT ASSISTANCE UNIT

Cap. out (MW)	Individual prob.	Cum. prob.
0	0.86609717	1.00000000
10	0.10812248	0.13390283
20	0.00562205	0.02578035
25	0.01767545	0.02015830
30	0.00015585	0.00248285
35	0.00220658	0.00232700
40	0.00000243	0.00012042
45	0.00011474	0.00011799
50	0.00000002	0.00000325
55	0.00000318	0.00000323
60	0.00000000	0.00000005
65	0.00000005	0.00000005
75	0.00000000	0.00000000

$LOLP_{A|B}$ = Pr. {Cap out > Reserve} = 0.00012042

[Reserve = (75 + 10) – 50 = 35 MW]

- The $LOLP_{A|B}$ obtained from the Venn diagram is same as obtained from the modified capacity outage table
- **IN THIS CASE A TIE LINE OF 10 MW CAPACITY WITH FOR = 0.0 IS EQUIVALENT TO A 10 MW UNIT OF FOR = 0.02228975**

CASE STUDY

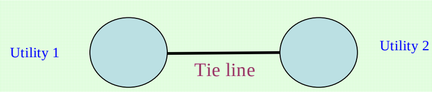
IEEE RELIABILITY TEST SYSTEM

Type of Unit	Unit Size (MW)	No. of Units	FOR	Incremental Cost ($/MWh)
Nuclear	400	2	0.12	5.592
Coal	150	4	0.04	11.160
Coal	350	1	0.08	11.400
Coal	80	4	0.02	14.882
Oil	200	3	0.05	19.870
Oil	100	3	0.04	20.080
Oil	10	5	0.02	28.558
Oil	20	4	0.10	37.500
Hydro	50	6	0.01	0.0

DEMAND DATA: 48-52 AND 1-8 WEEKS HOURLY LOADS OF IEEE-RTS

PEAK LOAD: 2850 MW, ENERGY : 4163.48 GWh

CASE STYDY (CONT'D)



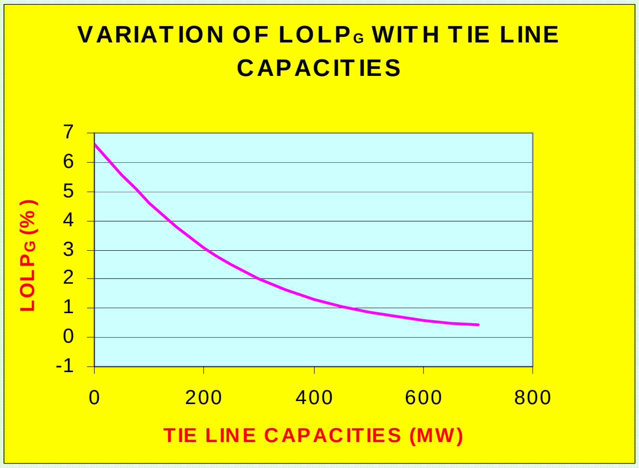
HYPOTHETICAL SYSTEM

Type of Unit	Unit Size (MW)	No. of Units	FOR	Incremental Cost ($/MWh)
Nuclear	500	1	0.13	4.500
Coal	400	2	0.13	14.300
Coal	350	1	0.13	15.100
Coal	250	1	0.08	18.600
Oil	350	1	0.14	30.400
Oil	200	2	0.10	35.000
Oil	50	4	0.11	43.200
Hydro	100	3	0.01	0.0

DEMAND DATA: 18-30 WEEKS HOURLY LOADS OF IEEE-RTS

PEAK LOAD: 2565 MW, ENERGY : 3964.143 GWh

CASE STYDY (CONT'D)



CASE STYDY (CONT'D)

TABLE: RELIABILITY INDICES AT DIFFERENT TIE LINE CAPACITIES OF THE INTERCONNECTED UTILITIES

TIE LINE CAPACITY (MW)	INDEPENDENT LOAD		CORRELATED LOAD	
	$LOLP_{1/2}$	$LOLP_{2/1}$	$LOLP_{1/2}$	$LOLP_{2/1}$
0.0	.00274	.06543	.00280	.06610
100	.00143	.04533	.00156	.04585
200	.00079	.03026	.00097	.03077
300	.00050	.01942	.00072	.02000
400	.00037	.01219	.00062	.01284
500	.00032	.00775	.00058	.00850
600	.00031	.00505	.00057	.00594
700	.00030	.00337	.00057	.00442

ENERGY GENERATION AND PRODUCTION COST OF INDIVIDUAL UTILITY AND OF GLOBAL SYSTEM

Table: Expected energy generation and production cost of two interconnected utilities (*pooling operation)

Tie Line Capacity (MW)	Exp. Energy generation (GWh)		Production cost (M$)		Global		
	System 1	System 2	System 1	System 2	Exp. Energy generation (GWh)	Exp. Unserved energy (GWh)	Production cost (M$)
0.0	4162.6505	3949.5223	33.234	44.593	8112.1727	15.4503	77.828
100	4332.9653	3785.3003	35.558	40.819	8118.2657	9.3569	76.377
200	4487.9633	3634.0474	37.744	37.526	8122.0107	5.6123	75.270
300	4616.8758	3507.3935	39.597	34.864	8124.2693	3.3537	74.461
400	4715.6351	3409.9606	41.044	32.843	8125.5957	2.0273	73.888
500	4780.6178	3348.7208	42.035	31.478	8126.3386	1.2844	73.513
600	4815.2336	3311.4950	42.598	30.701	8126.7286	0.8940	73.299
700	4830.0331	3296.8930	42.867	30.324	8126.9235	0.6991	73.192

∞*	--------	-------	------	------	8127.0849	0.5376	73.093

Global production cost saving from interconnection

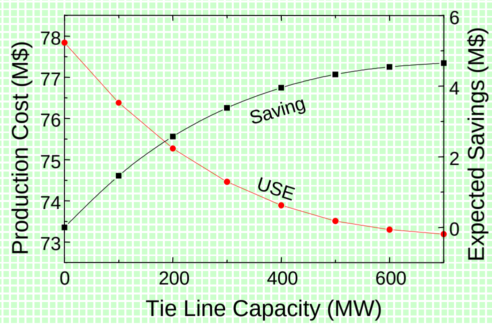
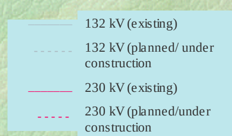
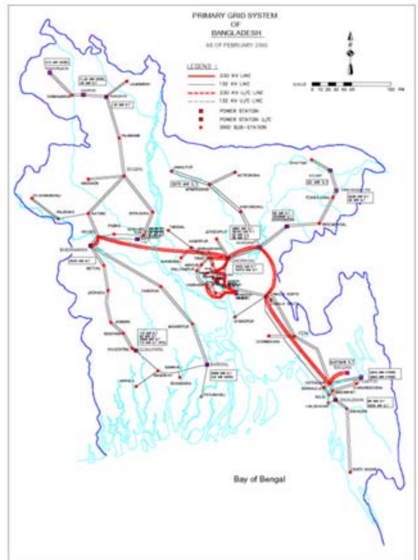


Fig: Global Expected saving and Expected unserved energy Vs. tie line capacity

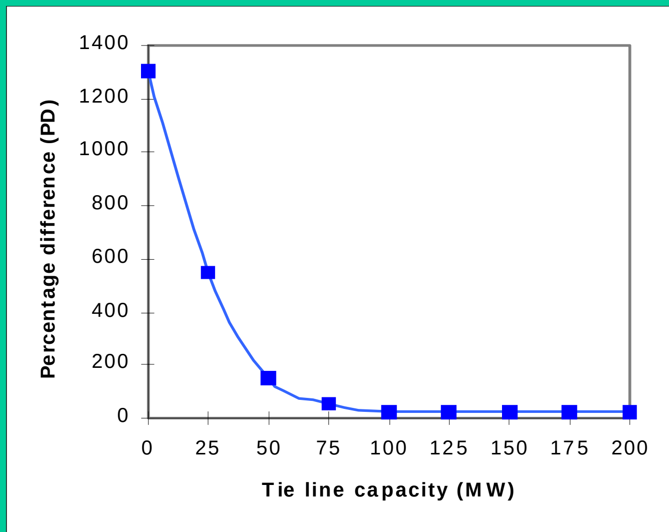
Transmission Line Scenario



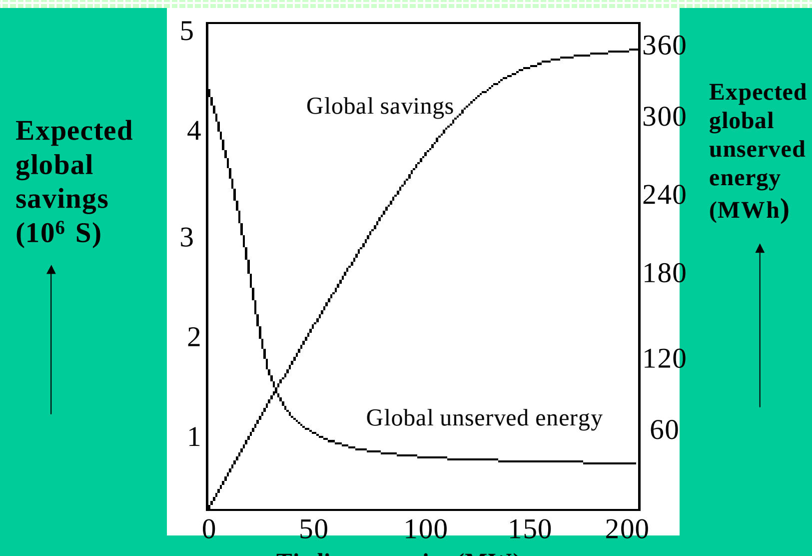


LOLP for different tie line capacities

Tie line capacity (MW)	$LOLP_E$ (%)	$LOLP_W$ (%)	$LOLP_{E\|W}$ (%)	$LOLP_{W\|E}$ (%)	$LOLP_G$ (%)
0.0	0.493890	1.175805	0.493890	1.175805	1.640265
10.0	0.493890	1.175805	0.373332	0.817527	1.161430
20.0	0.493890	1.175805	0.284333	0.572198	0.827102
30.0	0.493890	1.175805	0.217372	0.389823	0.577766
50.0	0.493890	1.175805	0.132582	0.193888	0.297040
75.0	0.493890	1.175805	0.087822	0.104923	0.163316
100.0	0.493890	1.175805	0.073535	0.082729	0.126834
125.0	0.493890	1.175805	0.070722	0.079014	0.120307
150.0	0.493890	1.175805	0.070493	0.078688	0.119751
175.0	0.493890	1.175805	0.070483	0.078678	0.119732
- - --	- - --	----	------	------	---------
$\propto$	0.493890	1.175805	0.070483	0.078678	0.119732



Percentage Difference in Global LOLP vs. Tie Line Capacity



Expected global unserved energy and expected global savings vs. tie line capacity

CONCLUSIONS

- **INTERCONNECTION OPTION SHOULD BE EXPLORED IN GENERATION EXPANSION ANALYSIS IN PARALLEL WITH THE OPTION OF NEW CAPACITY ADDITION IN THE SYSTEM**
- **EQUIVALENT GENERATING UNIT CAPACITY TO A TIE LINE CAPACITY MAY BE EASILY EVALUATED. THEN TWO OPTIONS, INTERCONNECTION AND INSTRALLATION OF NEW GEN. UNIT, SHOULD BE COMPARED**
- **INCREASE OF TIE LINE CAPACITY BEYOND CERTAIN LIMIT DOES NOT IMPROVE SYSTEM RELIABILITY OR COST**

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

MULTI AREA EVALUATION APPROACH IN A SINGLE AREA SYSTEM WITH LIMITED TRANSMISSION CAPABILITIES

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SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

A POWER SYSTEM WITH LIMITED TRANSMISSION FACILITY

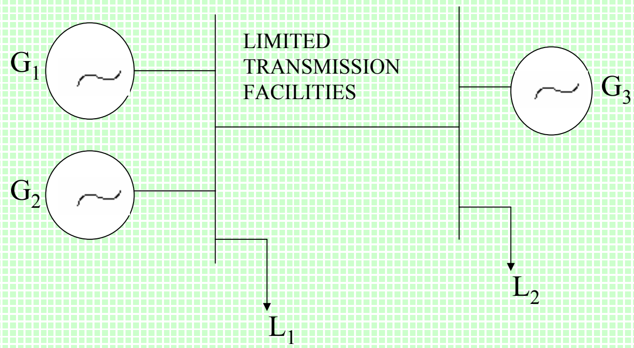


Fig. 1: A Power System with limited Transmission Facility

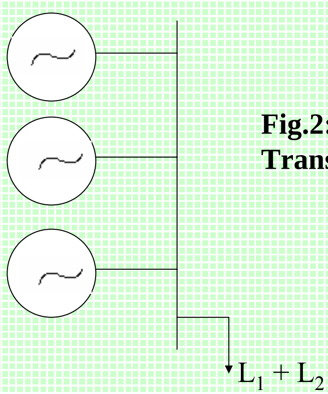
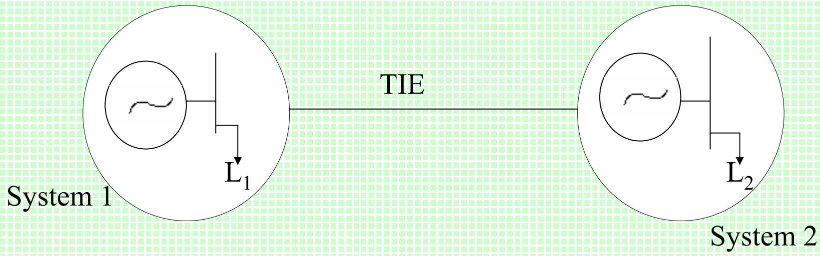


Fig.2: A Power System with no Transmission Constraint

OBSERVATIONS

- System in Fig. 1 is not same as the system in Fig. 2 from reliability evaluation point of view.
- System in Fig. 1 resembles a two-area interconnected system
- System in Fig. 2 resembles a single area system
- Reliability evaluation techniques for the above two systems are different.

CONSIDERING TWO INTERCONNECTED SYSTEM



System Data of two interconnected system

System	No. of units	Unit capacity (MW)	FOR	Peak Load (MW)	Installed capacity (MW)
1	2 1	10 30	0.2 0.1	30	50
2	2 1	15 25	0.1 0.3	30	55

Capacity Outage Table

Capacity on outage (MW)	Probabilities	
	System 1	System 2
0	0.576	0.567
5	---	---
10	0.288	---
15	---	0.126
20	0.036	---
25	---	0.243
30	0.064	0.007
35	---	---
40	0.032	0.054
45	---	---
50	0.004	---
55	---	0.003

		0		10		20		30		40		50
		0.576	--	0.28 8	--	0.036	--	0.064	--	0.032	--	0.004
0	0.567	0.32659		0.1633		0.02041		0.03628		0.01814		0.0028
--	---											
--	---											
15	0.126	0.07258		0.0362		0.00454		0.00804		0.004032		0.000504
--	--											
25	0.243	0.13986		0.0699		0.00874		0.01555		0.007776		0.000977
30	0.007	0.00403		0.0020		0.00025		0.00048		0.000224		0.000028
--	--											
40	0.05	0.03404		0.0155		0.00194		0.00345		0.001228		0.000216
--	---											
--	---											
55	0.008	0.00172		0.0003		0.00010		0.00019		0.000096		0.00002

R=25 MW

TC=10 MW

Joint Probability matrix (Venn diagram)

RELIABILITY INDICES

Loss of load probability(LOLP) of system 1 = $\mathbf{LOLP_1 = 0.1}$

LOLP of system 2 = $\mathbf{LOLP_2 = 0.064}$

LOLP of system 1 assisted by system 2 = $\mathbf{LOLP_{1/2} = 0.0556}$

LOLP of system 2 assisted by system 1 = $\mathbf{LOLP_{2/1} = 0.0580}$

LOLP of global system = $\mathbf{LOLP_G = 0.1072}$

CAPACITY OUTAGE TABLECONSIDERING SINGLE AREA SYSTEM

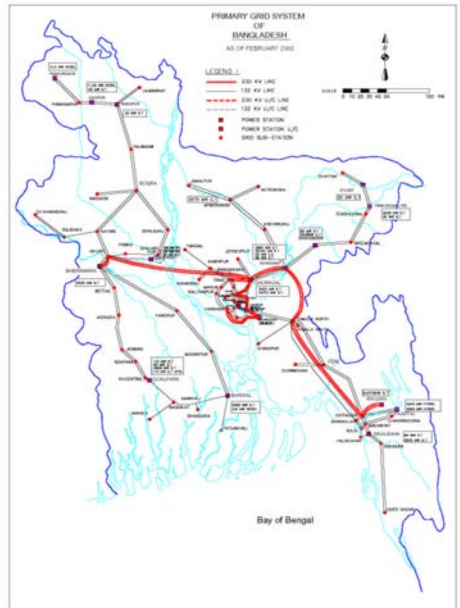
Capacity Out (MW)	Individual Probability	Cumulative Probability
0	0.3266	1.0
10	0.1633	0.6734
15	0.0726	0.5101
20	0.0204	0.4375
25	0.1763	0.4171
30	0.0403	0.2409
35	0.0745	0.2005
40	0.0513	0.4260
45	0.0168	0.0748
50	0.0181	0.0580
55	0.0213	0.0399
60	0.0024	0.0186
65	0.0091	0.0162
70	0.0037	0.0070
75	0.0011	0.0034
80	0.0018	0.0023
85	0.0002	0.0005
90	0.0002	0.0003
95	0.0001	0.0001
105	0.0000	0.0000

- **FOR A PEAK LOAD OF 30 MW (RESERVE =105-30=75 MW)**
  LOLP = 0.0023

- **NOTE THAT WHEN THE SYSTEM IS TREATED AS A TWO AREA INTERCONNECTED SYSTEM THE GLOBAL LOLP ($LOLP_G$) = 0.1072**

- **THAT IS, THE RELIABILITY INDEX OBTAINED THROUGH SINGLE AREA APPROACH WIDELY VARIES FROM THAT OBTAINED THROUGH TWO AREA APPROACH**

Transmission Line Scenario



- 132 kV (existing)
- 132 kV (planned/ under construction
- 230 kV (existing)
- 230 kV (planned/under construction

LOLP for different tie line capacities

Tie line capacity (MW)	$LOLP_E$ (%)	$LOLP_W$ (%)	$LOLP_{E\|W}$ (%)	$LOLP_{W\|E}$ (%)	$LOLP_G$ (%)
0.0	0.493890	1.175805	0.493890	1.175805	1.640265
10.0	0.493890	1.175805	0.373332	0.817527	1.161430
20.0	0.493890	1.175805	0.284333	0.572198	0.827102
30.0	0.493890	1.175805	0.217372	0.389823	0.577766
50.0	0.493890	1.175805	0.132582	0.193888	0.297040
75.0	0.493890	1.175805	0.087822	0.104923	0.163316
100.0	0.493890	1.175805	0.073535	0.082729	0.126834
125.0	0.493890	1.175805	0.070722	0.079014	0.120307
150.0	0.493890	1.175805	0.070493	0.078688	0.119751
175.0	0.493890	1.175805	0.070483	0.078678	0.119732
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∝	0.493890	1.175805	0.070483	0.078678	0.119732

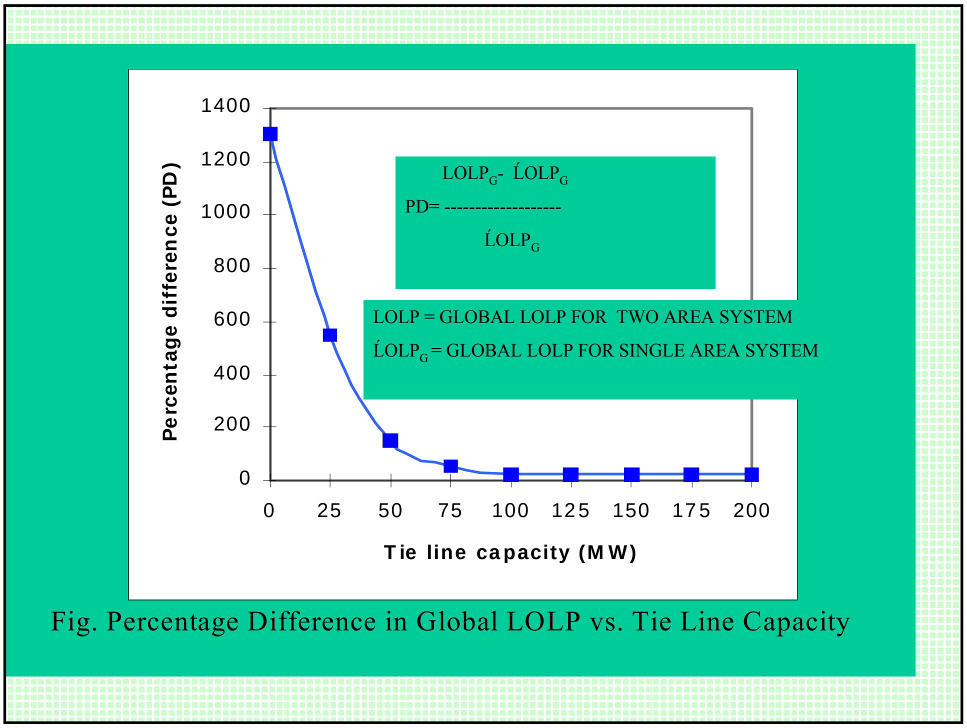
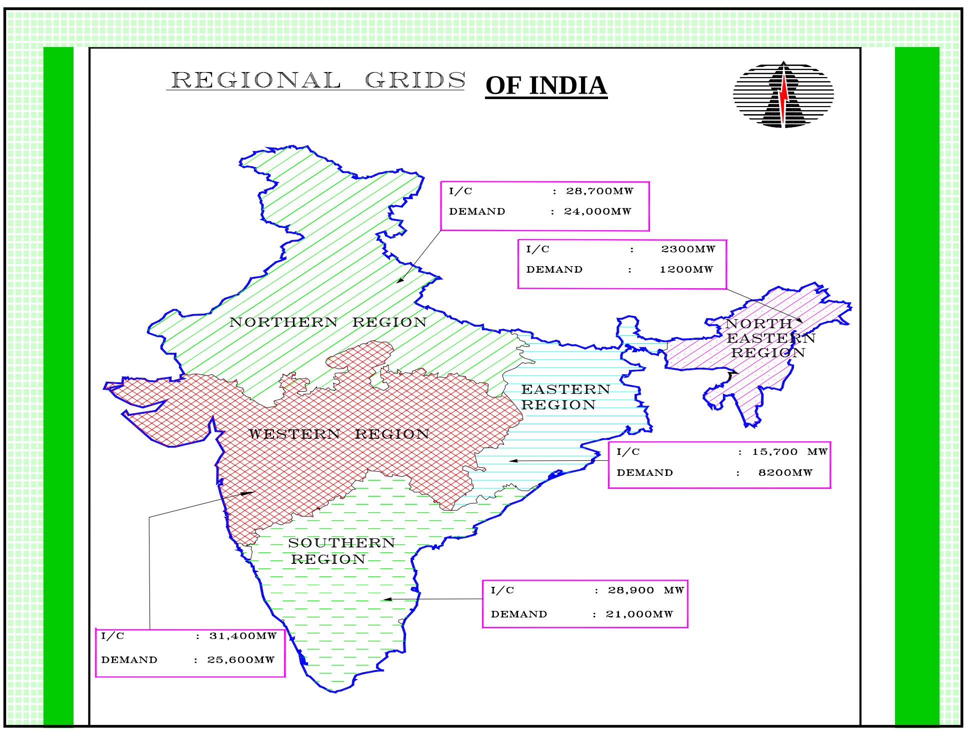
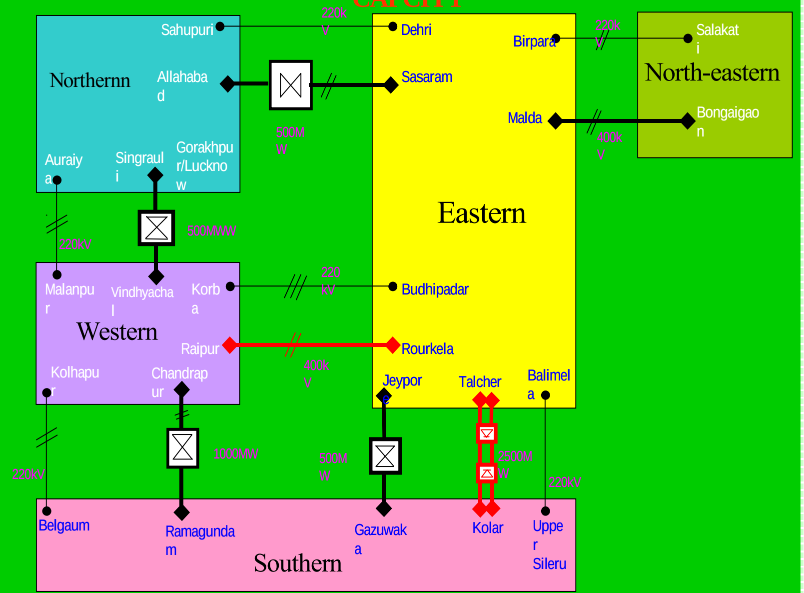


Fig. Percentage Difference in Global LOLP vs. Tie Line Capacity



INDIA'S MAJOR INTER REGIONAL LINKS-8000 MW CAPCITY



CONCLUSION

- A POWER SYSTEM WITH LIMITED TRANSMISSION CAPABILITIES BETWEEN REGIONS SHOULD NOT BE TREATED AS A SINGLE AREA SYSTEM IN EVALUATING RELIABILITY INDEX.
- BANGLADESH POWER SYSTEM IS A TYPICAL EXAMPLE OF A POWER SYSTEM TO BE TREATED AS AN INTERCONNECTED SYSTEM (EASTERN AND WESTERN GRIDS) IN EVALUATING RELIABILITY INDICES.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

SYSTEM RELIABILITY LEVEL: IMPACTS OF LOAD MANAGEMENT SCHEMES

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SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

- **BASIC APPROACHES OF LOAD MANAGEMENT SCHEMES**
- **IMPACTS OF LOAD MANAGEMENT SCHEMES ON THE SYSTEM RELIABILITY.**
- **EQUIVALENCE OF NEW CAPACITY ADDITION TO THE MAGNITUDE OF LOAD MANAGEMENT**
- **IMPACTS OF LOAD MANAGEMENT ON THE RELIABILITY OF INTERCONNECTED SYSTEMS**
- **COMPARISON OF IMPACTS OF DIFFERENT LOAD MANAGEMENT SCHEMES**
- **CONCLUSION**

LOAD MANAGEMENT

Load management is the deliberate control or influencing of customer load in order to alter the pattern of electricity use by time-shifting some of the deferrable loads

Basic approaches of load management

1. Direct control
2. Indirect control or customer incentives
3. Energy storage

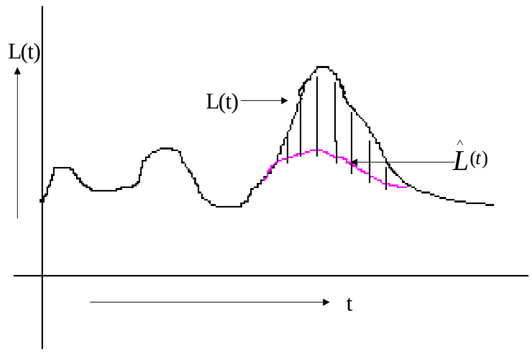
DIRECT CONTROL

In direct control approach, the utility controls the customer loads usually during the peak period. A unidirectional or bi-directional communication system is used to activate control devices at the customer location. Direct load control is attractive to utilities because they can plan for specific demand level.

(a) $\hat{L}(t) = L(t) - (a\ L(t))\ \lambda_{(t_1\ \ t_2)}(t) \quad ;\ 0 \leq a \leq 1$

In this approach, load is reduced by a certain fixed percentage during the peak hours.

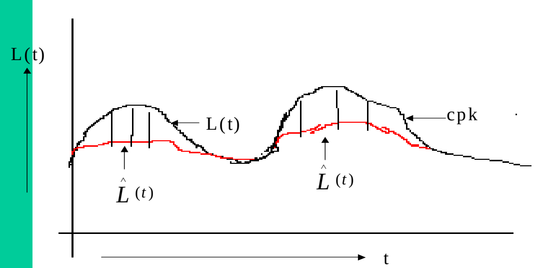
DIRECT CONTROL (CONT.)



DIRECT CONTROL (CONT.)

(b) The second direct load control approach is to reduce the demand whenever it exceeds a prefixed value.

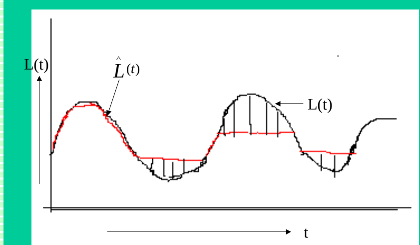
$$\hat{L}(t) = L(t) - (L(t) - CPK)\,\lambda\,(L(t))$$



INDIRECT CONTROL

The art of indirect control approach is based on the incentives/ motivation of customers to shift some of the loads from peak to off-peak period.

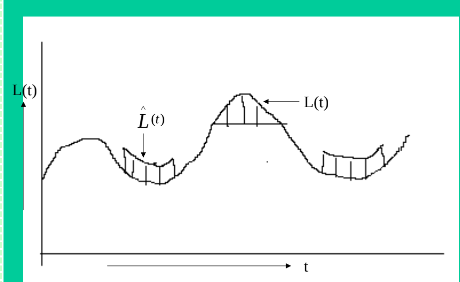
$$\hat{L}(t) = L(t) + \sum_i L(t_i) a_i - bL(t)\ \lambda_{(t_r,\ t_n)}\ (t)$$



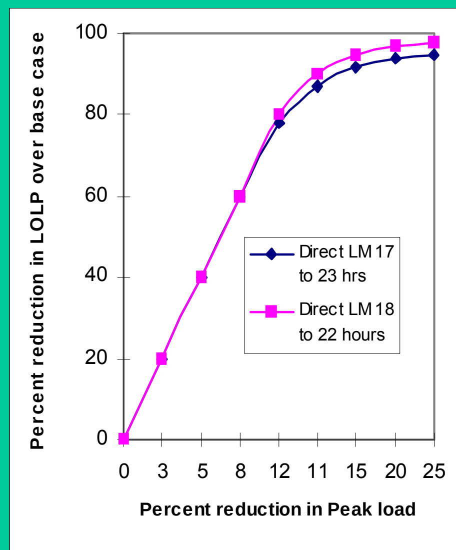
ENERGY STORAGE

Energy storage is the use of electricity during off-peak hours to store energy for use during on-peak period . Pumped hydro storage is almost only successful form of storage system.

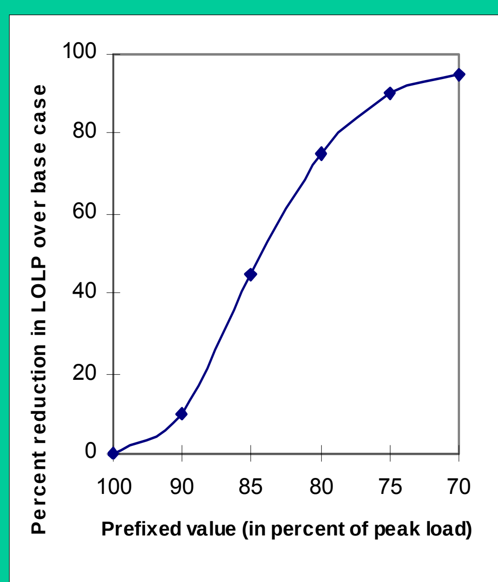
$$\hat{L}(t) = L(t) - a\ \ L(t)\ \ \lambda_{(t_r,\ t_n)}\ (t) + bL(t)\lambda_{(t_3, t_4)}\ (t)$$



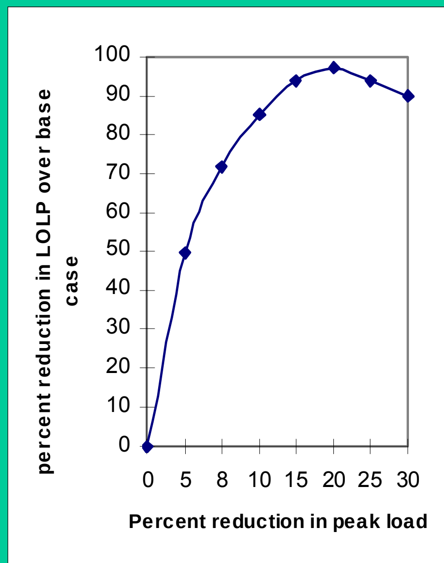
EFFECT OF DIRECT LOAD CONTROL (LOAD REDUCED)



EFFECT OF DIRECT LOAD CONTROL (CONSTANT PEAK)



EFFECT OF INDIRECT LOAD CONTROL



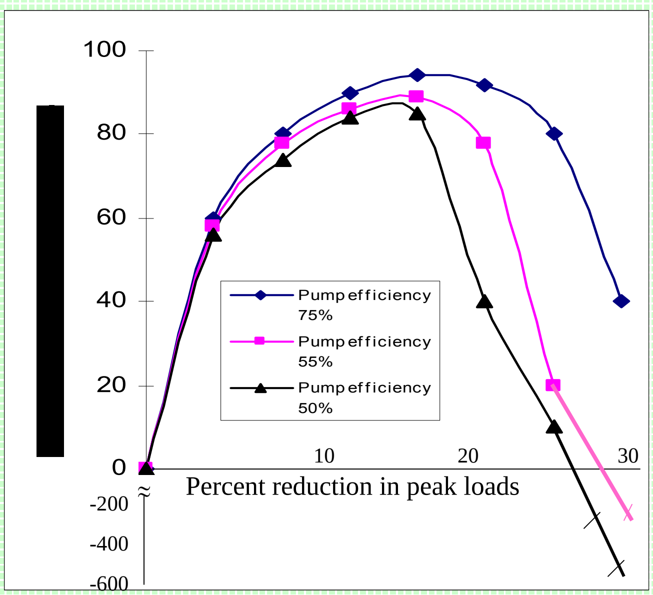


Fig. Impacts of Energy Storage Scheme on Reliability

COMPARISON OF LOAD MANAGEMENT SCHEMES WITH CAPACITY ADDITION

Generation Capacity addition (MW)	Direct	Indirect	Energy storage	
	(% reduction of load)	(% reduction of load)	(% reduction of load)	Pump efficiency (%)
5			25	55
40			20	50
50		5	5	71.5
60			20	55
85			25	71.5
90	10	10		
100			10	50
110		30	15	50
120			20	71.5
130	15	15		
140		25		
145		20		
150	20			
160	25			
165	30			
185			10	71.5

IMPACT OF LOAD MANAGEMENT ON TWO AREA INTERCONNECTED SYSTEM

DIRECT CONTROL

a) LOLPs of the global system for the reduced load (Load reduced by 10% during peak hours)

Tie-line (MW)	Base-case	Load reduced in system X only	Load reduced in system Yonly	Load reduced in both systems
0	0.06856	0.06741	0.05181	0.05066
100	0.04707	0.04641	0.03399	0.03332
200	0.03141	0.03094	0.02153	0.02106
300	0.02039	0.01994	0.01348	0.01304
400	0.01312	0.01261	0.00868	0.00818
500	0.00875	0.00816	0.00572	0.00513

DIRECT CONTROL (CON'D)

b) Any value exceeding 2565 MW in X system is reduced to that and in system Y by the pre-specified value 2308.5 MW

Tie-line (MW)	Base-case	Load management applied to system X only	Load management applied to system Y only	Load management applied to both system
0	0.06856	0.06784	0.06081	0.06009
100	0.04707	0.04669	0.04293	0.04254
200	0.03141	0.13112	0.02692	0.02664
300	0.02039	0.02016	0.01630	0.01608
400	0.01312	0.01287	0.01069	0.01045
500	0.00875	0.00849	0.00720	0.00696

LOLPs of the global system for the energy storage scheme

Tie-line (MW)	Base-case	Load management applied to system X only	Load management applied to system Y only	Load management applied to both systems
0	0.06856	0.06744	0.05509	0.05396
100	0.04707	0.04642	0.03600	0.03534
200	0.03141	0.03094	0.02269	0.02221
300	0.02039	0.01994	0.01409	0.01365
400	0.01312	0.01262	0.00900	0.00850
500	0.00875	0.00817	0.00589	0.00530

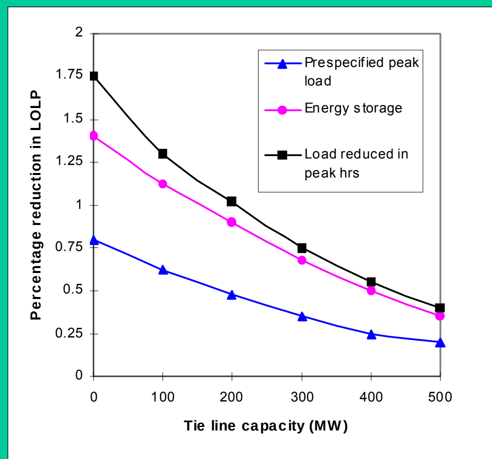


Fig. LOLP reduced by different management schemes

CONCLUSION

- ❖THE APPLICATION OF LOAD MANAGEMENT SCHEMES SHOW AN IMPROVEMENT OF SYSTEM RELIABILITY ONLY UP TO CERTAIN LIMIT OF LOAD REDUCTION IN MOST OF THE CASES; EXCEEDING THIS LIMIT DETERIORATES THE RELIABILITY
- ❖LOAD MANAGEMENT MAY BE CONSIDERED AS AN ALTERNATIVE TO NEW CAPACITY INSTALLATION
- ❖LOAD MANAGEMENT SCHEMES MAY BE APPLIED INSTEAD OF INCREASING TIE LINE CAPACITY.

SOUTH ASIA REGIONAL INITIATIVE/ENERGY

SYSTEM RELIABILITY LEVEL: IMPACTS JOINT OWNERSHIP OF GENERATION

USAID

WINROCK INTERNATIONAL
Putting Ideas to Work

Md. Quamrul Ahsan

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SARI ENERGY

SHORT TERM TRAINING ON 'RELIABILITY AND OPERATIONAL ASPECTS OF REGIONAL GRID'

CONTENTS

REASONS OF JOINLY OWNED CAPACITY BUILD UP

- USE OF UNTAPPED NATURAL RESOURCES FOR GLOBAL BENEFITS
- REQUIREMENT OF HUGE INVESTMENT FOR THE INSTALLATION OF LARGE GENERATING UNITS

PROSPECT OF JOU IN THE REGION

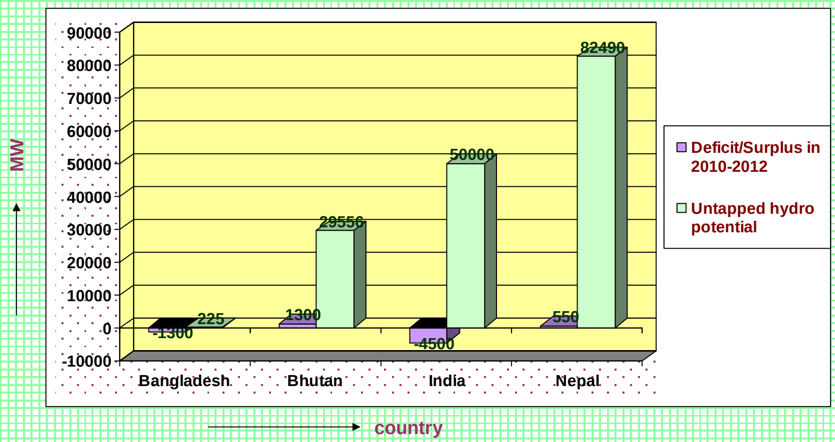
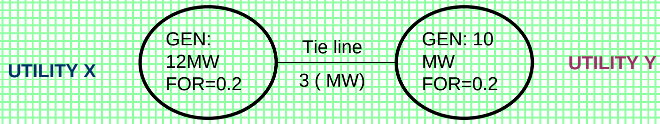


Fig: Forecasted electrical energy supply status in 2010-2012 (Nexant) and uptapped hydro potential (ecomic reforms……….)

CONCEIVING OF IMPACTS OF JOU THROUGH HEURISTIC APPROACH



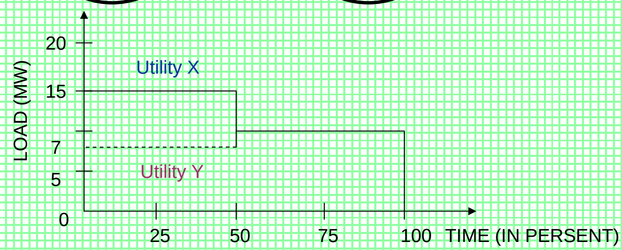


FIG: LOAD PROFILE OF TWO UTILITIES

Table: Generation capacity state without JOU

STATE OF GENERATORS		DURATION (time in present)	
UTILITY X	UTILITYY	with load levels 15, 7 MW	with load levels 10, 10 MW
ON	ON	32	32
ON	OFF	8	8
OFF	ON	8	8
OFF	OFF	2	2

EVALUATION OF ENERGY TRANSACTION OF INTERCONNECTED UTILITIES WITHOUT JOU. (unit of single ownership)

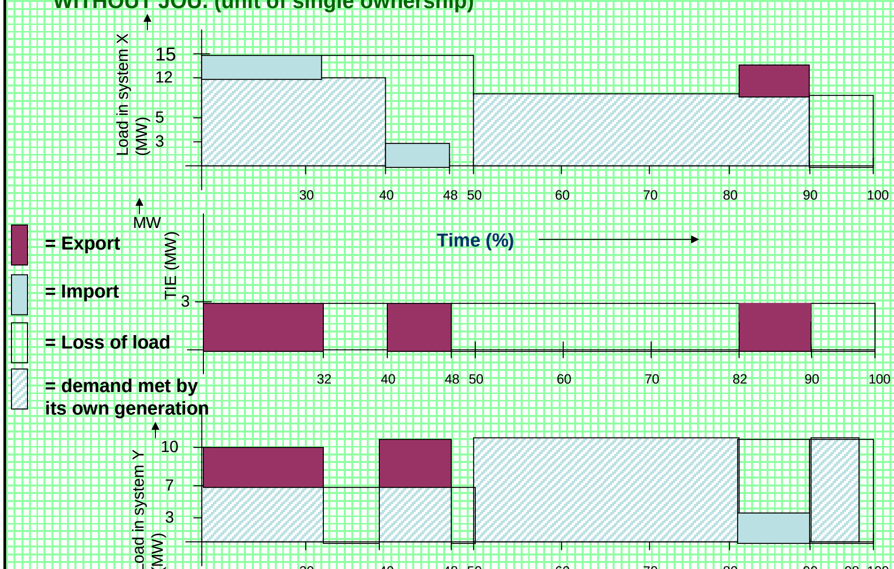


FIG: LOAD LEVELS AND POSSIBLE TRANSACTION WITHOUT JOU

ES_X =12×.4+10×.4+3×.08=9.04 MWh

ES_Y =10×.32+.08×10+10×.4=8.0 MWh

ES_G =17.04 MWh

$USE_G = ED_G - ES_G$={(15+10)+(7+10)} ×0.5-17.04=3.96 MWh

EXP_G= (0.32+.08 ×2) ×3=1.44 MWh

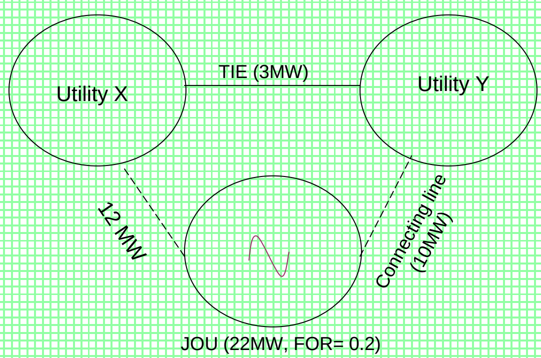
ES= ENERGY SUPPLY

USE= UNSERVED ENERGY

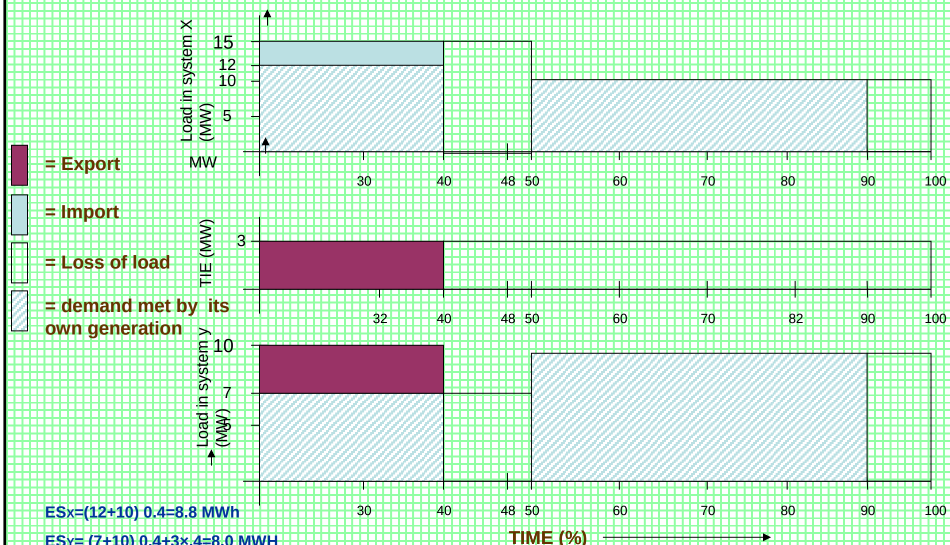
ED= ENERGY DEMAND

EXP=EXPORT

EVALUATION OF ENERGY TRANSACTION OF INTERCONNECTED UTILITIES WITH JOU (CONFIGARATION 1)



EVALUATION OF ENERGY TRANSACTION OF INTERCONNECTED UTILITIES WITH JOU (CONFIGARATION 1) (cont'd)



ES_X=(12+10) 0.4=8.8 MWh

ES_Y= (7+10) 0.4+3×.4=8.0 MWH

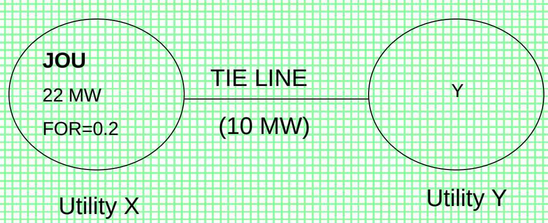
ES_G=16.8 MWh

USE_G= 4.2 MWh

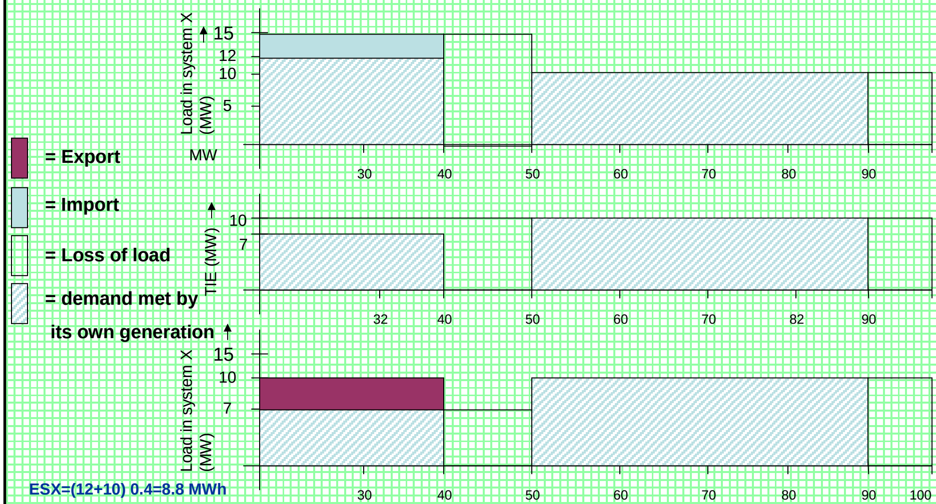
EXP_G= 1.2MWh

Fig: LOAD LEVELS AND POSSIBLE TRANSACTIONS WITH JOU.

EVALUATION OF ENERGY TRANSACTION OF INTERCONNECTED UTILITIES WITH JOU (CONFIGURATION 2)



EVALUATION OF ENERGY TRANSACTION OF INTERCONNECTED UTILITIES WITH JOU (CONFIGURATION 2) (CONT'D)



ESX=(12+10) 0.4=8.8 MWh

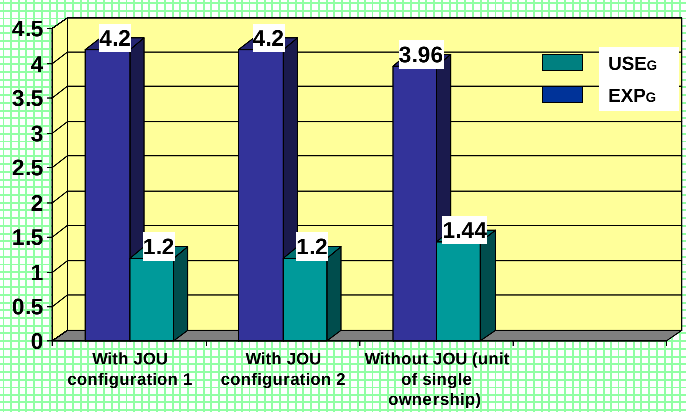
ESY= (10+10) 0.4 =8.0 MWH

ESG=16.8 MWh

USEG= 4.2 MWh

EXPG= 1.2MWh

IMPACTS OF JOU



METHODOLOGY TO EVALUATE TWO INTERCONNECTED UTILITIES WITH JOU

- EVALUATION TECHNIQUE IS DIFFERENT FROM THAT OF INTERCONNECTED UTILITIES WITH SINGLE OWNERSHIP UNITS
- SEGMENTATION METHOD IS THE ONLY AVAILABLE TECHNIQUE TO EVALUATE INTERCONNECTED UTILITIES WITH JOUs

SALIENT ASPECTS OF THE METHODOLOGY THAT ARE DIFFERENT FROM THOSE OF THE METHODOLOGY WITH SINGLE OWNERSHIP UNITS

EVALUATION OF RELIABILIYY INDICES

- NUMBER OF SEGMENT ARE DECIDED BY INCORPORATING THE MODIFIED VALUE OF TIE LINE CAPACITY
- ALL THE SINGLE OWNERSHIP UNITS ARE COVOLVED TO OBTAIN THE JOINT PROBABILITY MATRIX OF SEGMENTS (VENN DIAGRAM)
- RELIABILLITY INDICES ARE CALCULATED FOR EACH STATE OF THE JOU SEPARATELY
- DURING THE EVALUATION OF INDICES THE TIE LINE CAPACITY IS APPROPRIATELY MODIFIED
- THE RELIABILITY VALUES OBTAINED FOR EACH STATE OF JOU ARE MULTIPLIED BY THE STATE PROBABILITY
- TO OBTAIN THE FINAL RELIABILITY INDEX THE CORRESPONDING VALUE OBTAINED FOR EACH STATE IS ADDED.

ILLUSTRATION OF DIFFERENT STEPS OF THE METHODOLOGY TO EVALUATE RELIABILITY INDICES THROUGH A NUMERICAL EXAMPLE

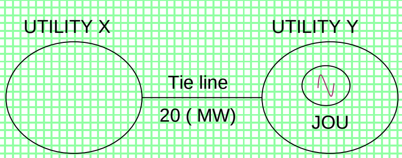


FIG: Two interconnected utilities with a JOU

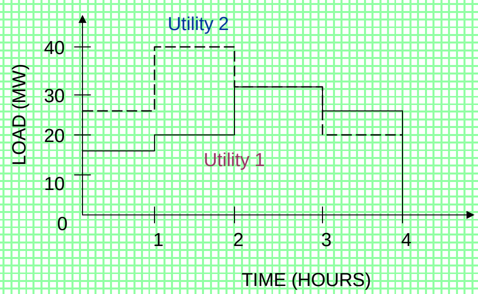


Fig: hourly load profile of two utilities

Table: generation system description

Utility X			Utility Y		
No of units	Capacity (MW)	FOR	No of units	Capacity (MW)	FOR
2	10	0.2	1	15	0.1
1	20	0.1	1	25	0.3
JOU	$SH_{X=}$ 10 MW		$SH_{Y=}$ 15 MW		0.1
	Located in utility y				

FORMATION OF SEGMENTS AND DEVELOPMENT OF ITS PDF

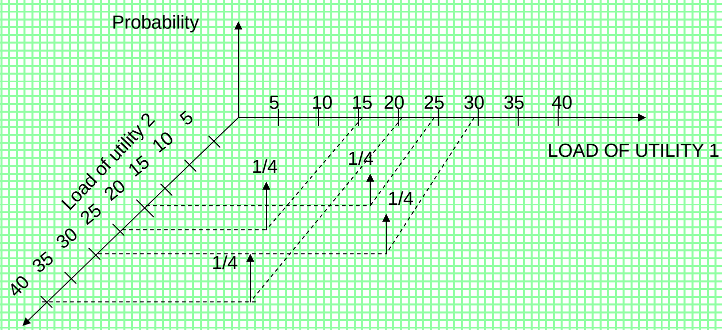


Fig: joint PDF OF correlated loads of two utilities

FORMATION OF SEGMENTS AND DEVELOPMENT OF ITS PDF (cont'd)

Utility X (MW) →

Utility y (MW) ↓

y \ X	10		20		30		40		50		60
15			1								
	1										
25				1							
35		1									
45											
55											
65											

Fig: Joint PDF of load (probability values in the boxes are divided by 4)

CONVOLUTION OF UNITS OF SINGLE OWNERSHIP

Utility X (MW) →

Utility y (MW) ↓

y \ X	10		20		30		40		50		60
15							.063		.02016		.00252
							.02016		.00252		
25								.063		.02016	.00252
							.007		.00224		.00028
35							.00224	.02016	.00028	.00252	
			.16552	.04032	.07776	.02016	.027	.007	.00864	.00224	.00136
45	.16552		.07776		.027		.00864		.00108		
		.04032		.17568		.08476		.02924		.00892	.00106
55			.01728		.00864		.003		.00096		.00012
	.01728	.15552	.00864	.07776	.003	.027	.00096	.00864	.00012	.00108	
65				.01728		.00864		.003		.00096	.0012
75		.01728		.00864		.003		.00096		.00012	
85											

Fig: Joint PDF after convolving all the units except the JOU (probability values in the boxes to be divided by 4)

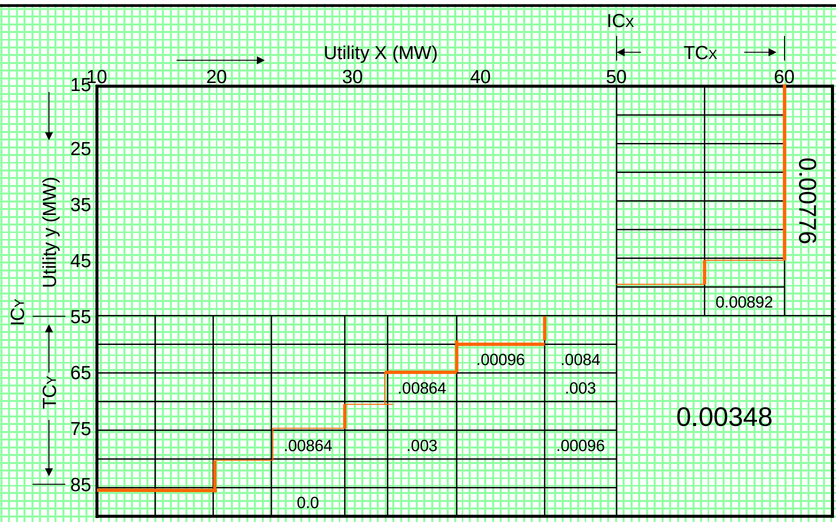


Fig: different zones of integration while the JOU is considered to be available

LOLP $_{X/Y}$ (C_{JOU}>0)=1/4(0.00348+0.00776+0.00892)
=0.00504

LOLP $_{Y/X}$ (C_{JOU}>0)=1/4(0.00348+0.0+0.00864+0.003+0.00096
+0.00864 +0.003+0.00096+0.00864)
=0.00933

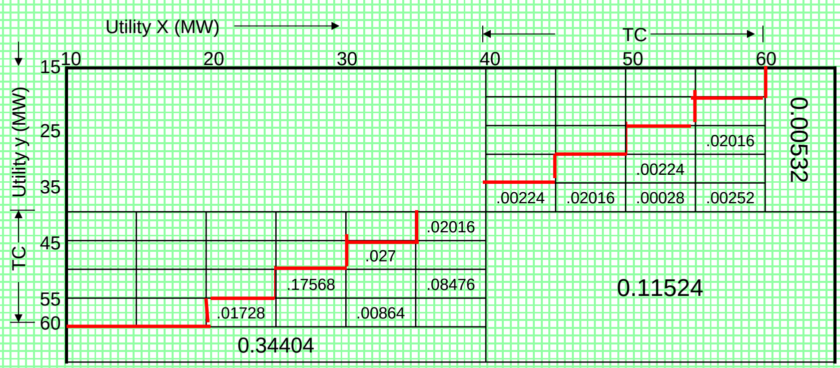


Fig: Different zones of integration while the JOU is considered to be unavailable

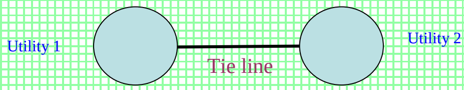
LOLP $_{X/Y}$(C_{JOU}=0)=1/4[0.11524+0.00532+(0.00224+0.02016
+0.00028+0.00252+0.00224+0.02016)]
=0.04204

LOLP $_{Y/X}$ (C_{JOU}>0)=1/4 [0.11524+0.34404+(0.01728+0.17568
+0.027+0.02106+0.00864+0.08476)]
=0.1982

LOLP $_{X/Y}$ =(0.00504 X 0.9)+(0.04204 X 0.1)
=0.00874

LOLP $_{Y/X}$ =(0.00933 X 0.9)+(0.1982 X 0.1)
=0.028217

CASE STUDY



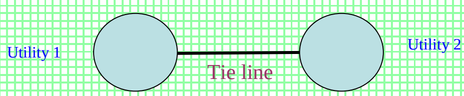
IEEE RELIABILITY TEST SYSTEM

Type of Unit	Unit Size (MW)	No. of Units	FOR	Incremental Cost ($/MWh)
Nuclear	400	2	0.12	5.592
Coal	150	4	0.04	11.160
Coal	350	1	0.08	11.400
Coal	80	4	0.02	14.882
Oil	200	3	0.05	19.870
Oil	100	3	0.04	20.080
Oil	10	5	0.02	28.558
Oil	20	4	0.10	37.500
Hydro	30	6	0.01	0.0

DEMAND DATA: 48-52 AND 1-8 WEEKS HOURLY LOADS OF IEEE-RTS

PEAK LOAD: 2850 MW, ENERGY : 4163.48 GWh

CASE STYDY (CONT'D)



HYPOTHETICAL SYSTEM

Type of Unit	Unit Size (MW)	No. of Units	FOR	Incremental Cost ($/MWh)
Nuclear	500	1	0.13	4.500
Coal	400	2	0.13	14.300
Coal	350	1	0.13	15.100
Coal	250	1	0.08	18.600
Oil	350	1	0.14	30.400
Oil	200	2	0.10	35.000
Oil	50	4	0.11	43.200
Hydro	100	3	0.01	0.0

DEMAND DATA: 18-30 WEEKS HOURLY LOADS OF IEEE-RTS

PEAK LOAD: 2565 MW, ENERGY : 3964.143 GWh

DESCRIPTION OF JOU: (350 MW COAL UNIT OF Y IS COMBAINED WITH 150 MW COAL UNIT OF X TO FROM THE JOU)

(CAPACITY=500 FOR=0.08 ,SHARE OF UTILITY X=30% ,SHARE OF UTILITY Y=70% ,LOCATED IN UTILITY Y)

Tie line capacity (MW)	Base case		System with a JOU	
	LOLP X/Y	LOLP Y/X	LOLP X/Y	LOLP Y/X
0.0	0.06582	0.002765	0.10663	0.00177
100	0.04569	0.00155	0.07492	0.00136
200	0.03063	0.00097	0.05221	0.00091
300	0.01988	0.00072	0.03564	0.00078
400	0.01277	0.00062	0.02357	0.00073
500	0.00846	0.00058	0.01517	0.00071
600	0.00591	0.00057	0.01010	0.00070
700	0.00439	0.00057	0.00706	0.00070

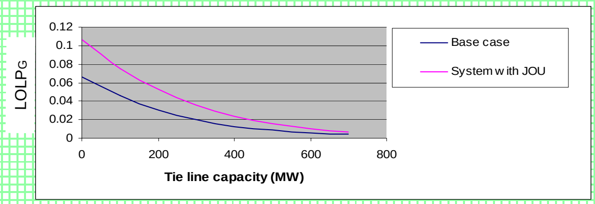


Fig: Global LOLP variation with tie-line capacity

Table: Variation of energy generation with tie line along with the base case

Tie line capacity (MW)	Base case		To area interconnected system with JOU	
	Expected energy Generation (GWh)		Expected energy Generation (GWh)	
	System X	System Y	System X	System Y
0.0	4171.13	3947.51	4820.30	3304.49
100	4292.88	3831.39	4741.39	3385.66
200	4406.85	3720.83	4666.89	3459.87
300	4506.59	3623.33	4602.84	3521.86
400	4586.93	3544.59	4580.44	3543.98
500	4645.83	3486.90	4600.07	3526.64
600	4688.37	3445.12	4616.15	3510.22
700	4719.45	3414.56	4630.445	3494.72

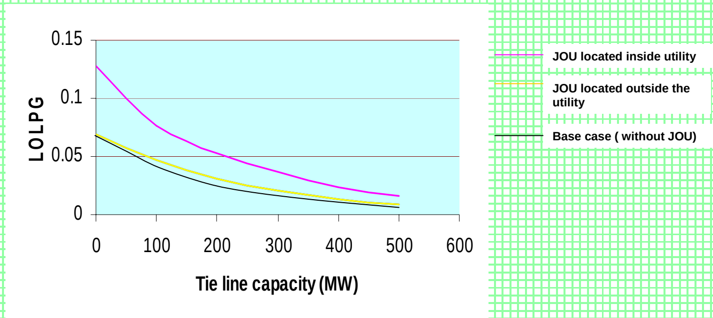


FIG: Impact of location of JOU on global reliability index

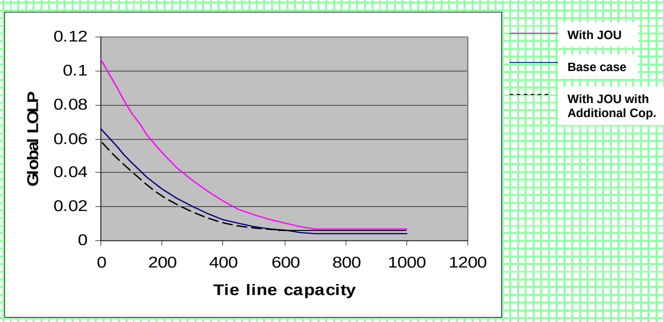


Figure: comparison between system including a JOU with and without tie line capacity and base case. [An additional tie line capacity of 150 MW exist to transfer the share of X. this is also used for export when JOU is on forced outage]

CONCLUTIONS

Interconnection

- **Improves the reliability**
- **Decreases the production cost of generation**
- **Increases the production cost savings of individual utility as well as the global network**

Causes creating benefits

- **Diversity of load (including time zone difference)**
- **Diversity of outages of generating unit**
- **Maximum use of global cheaper resources**

From the analysis

- **optimal tie line capacity**
- **equivalent capacity saving can be determined**

Although JOU has other benefits (investment constraint, harnessing natural resources) but it decreases

- **reliability and**
- **production cost savings of the interconnected system.**

This can be reduced by additional share transfer arrangement along with tie line.

It is expected that the global benefits of interconnection will increase with the joining of more and more utilities in the network.

TR 1: LOAD CARRYING CAPABILITY

An utility has three generating units. The generation and load models are given below:

Generation model:

Total No. of units: 3

Serial No.	Capacity (MW)	FOR
1	200	0.02
2	300	0.03
3	400	0.04

Load model:

Peak load: 350 MW

What will be the LOLP of the system ? If a new generating unit is added to the system of capacity 200 MW and FOR of 0.1 what will be the effective load carrying capability (ELCC) of this new unit when the system reliability is same as before. Also observe the impacts of FOR on ELCC by varying the FOR of the new unit.

TR 2: INTERCONNECTED SYSTEM

Two utilities, X and Y are interconnected through a tie line of capacity 5 MW. The generation and load models of both the systems are given below:

SYSTEM 'X'				SYSTEM 'Y'		
Generation System	Serial No.	Capacity (MW)	FOR	Serial No.	Capacity (MW)	FOR
	1	5	0.2	1	10	0.2
	2	10	0.1	2	2	0.1
Load Model	Peak Load (MW)	10		5		

Determine:

(i) Reliability of system X, $LOLP_X$
(ii) Reliability of system Y, $LOLP_Y$
(iii) Reliability of system X assisted by system Y, $LOLP_{X/Y}$
(iv) Reliability of system Y assisted by system X, $LOLP_{Y/X}$
(v) Reliability of the global system, $LOLP_G$

Also, calculate the above indices with (i) a different tie line capacity and (ii) a new unit added to system X or system Y.

Tutorial on Operational Aspects-1**:**

Steady state operation of a 3-area interconnected power system

An interconnected system consists of 3 areas as shown in Figure below. Area 1 comprises only bus 1, area 2 includes buses 2,4,6, and area 3 comprises buses 3 and 5. All the tie line data are given. The load and generation schedules for all the areas in a base case condition are also given. Using a Newton-Raphson or fast decoupled load flow analysis program determine the following. Use bus 1 as the slack.

a) Which area is importing or exporting how much power?

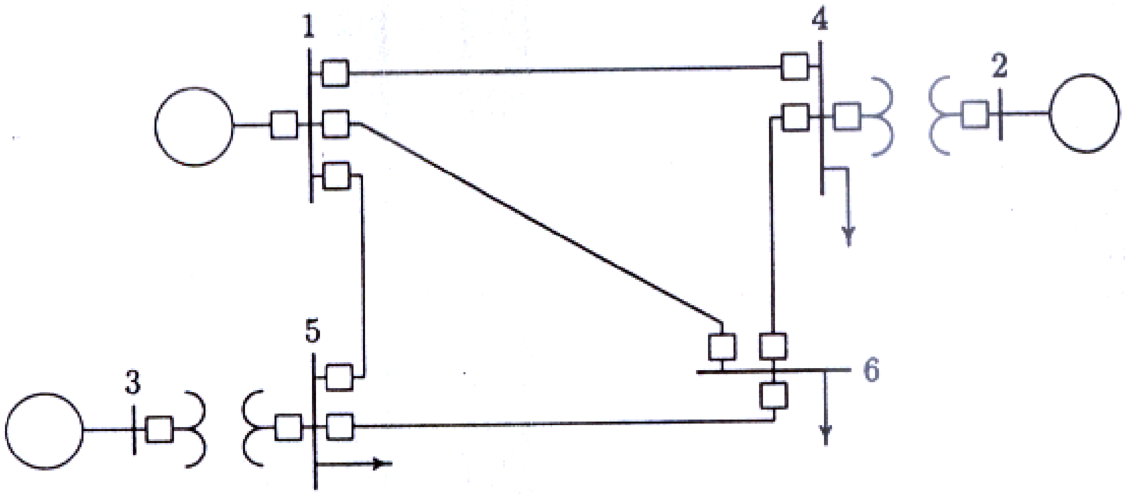
b) What happens to voltage at bus 6 incase the load at bus 6 in area 2 is increased from 160 MW + j110 MVAR to (i) 200 MW + j110 MVAR and (ii) 200 MW + j140 MVAR?

c) Repeat (b) if generation at bus 2 in area 2 is increased from 150 MW to 190 MW.

d) What happens to voltages at buses 4 and 6 and the line flows over all the tie lines to area 2 if generation at bus 2 decreased from 150 MW to 75 MW due to loss of a unit?

e) What happens to voltages at bus 6 if the load at bus 1 in area 1 is increased from 0.0 MW + j0.0 MVAR to 100MW + j 50 MVAR ?

Assume area 1 i.e. generator 1 has a generation limit of 200MW+j 200 MVAR. Based on this and the results from this case study as above, summarize your conclusions regarding requirements for the safe operation of interconnected systems.



LOAD DATA		
Bus No.	Load MW	Load Mvar
1	0	0
2	0	0
3	0	0
4	100	70
5	90	30
6	160	110

LINE DATA				
Bus No.	Bus No.	R, PU	X, PU	$\frac{1}{2}B$, PU
1	4	0.035	0.225	0.0065
1	5	0.025	0.105	0.0045
1	6	0.040	0.215	0.0055
2	4	0.000	0.035	0.0000
3	5	0.000	0.042	0.0000
4	6	0.028	0.125	0.0035
5	6	0.026	0.175	0.0300

GENERATION SCHEDULE				
Bus No.	Voltage Mag.	Generation, MW	Mvar Limits Min.	Mvar Limits Max.
1	1.06			
2	1.04	150	0	140
3	1.03	100	0	90

Tutorial on Operational Aspects-2**:**

Dynamic operation of a 3-area interconnected power system

A fault occurs near bus 6 on the tie line 1-6 of the system considered in tutorial-1. The machine data i.e. armature resistance and transient reactances in per unit and inertia constants in seconds on 100 MVA base are given below. The system was operating with the base case load and generation schedule considered for the tutorial –1.

MACHINE DATA			
Gen.	R_a	X'_d	H
1	0	0.20	20
2	0	0.15	4
3	0	0.25	5

a) Determine the stability of the whole system if the fault is cleared in 0.4 sec after the fault occurs.

b) Repeat (a) if generation at bus 2 is decreased from 150 MW to 75 MW due to loss of a unit in the prefault condition.

c) Repeat (a) if in the prefault condition the load at bus 6 in area 2 is increased from 160 MW + j110 MVAR to (i) 200 MW + j110 MVAR and (ii) 200 MW + j140 MVAR?

d) Repeat (b) if the fault is cleared in 0.3 seconds.

Based on the results from this case study as above, summarize your additional conclusions regarding requirements for the safe operation of interconnected systems.

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