Carnegie Mellon

Electric Energy Systems Group

Electrical & Computer ENGINEERING

A Method for Assessing Relative Value of Central Generation and Distributed Energy Resources (DERs) in Distribution Feeders

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Outline

- Major challenges and opportunities

  -- defining efficiency metrics for systematic use by all

  --assessing multiple value of a specific technology within a given system [1-8]

  --designing IT infrastructure to harvest hidden efficiencies across transmission and distribution systems (possible) [6-8]

  --designing market rules to support harvesting hidden efficiencies [9-11]

- A method to consider generation and demand using the same efficiency metrics
- An IT-enabled method for assessing relative contributions of central generation and DERs using the same efficiency metrics; distribution system examples.
- An IT-enabled method for integrating efficiency effects of DERs in the existing electricity markets; the key role of aggregators; examples. (Ilic, Wed presentation on seams solutions)
- Concluding remarks

Efficiency metrics for systematic use by all?

- Multiple values brought by different technologies [2]
- **Physical efficiency of stand-alone components (generation, demand)**
- **Physical efficiency due to loss delivery savings**
- **Physical efficiency due to reduced reserve requirements (reliability reserves)**
- **Physical efficiency due to temporal shifts during normal operations (peak load shaving)**
- **Economic efficiency in electricity markets (spot and capacity)**
- These are not additive. System-dependent.
- Tradeoffs defined by the system users, not by the hard constraints.
- Need a systematic method for evaluating.

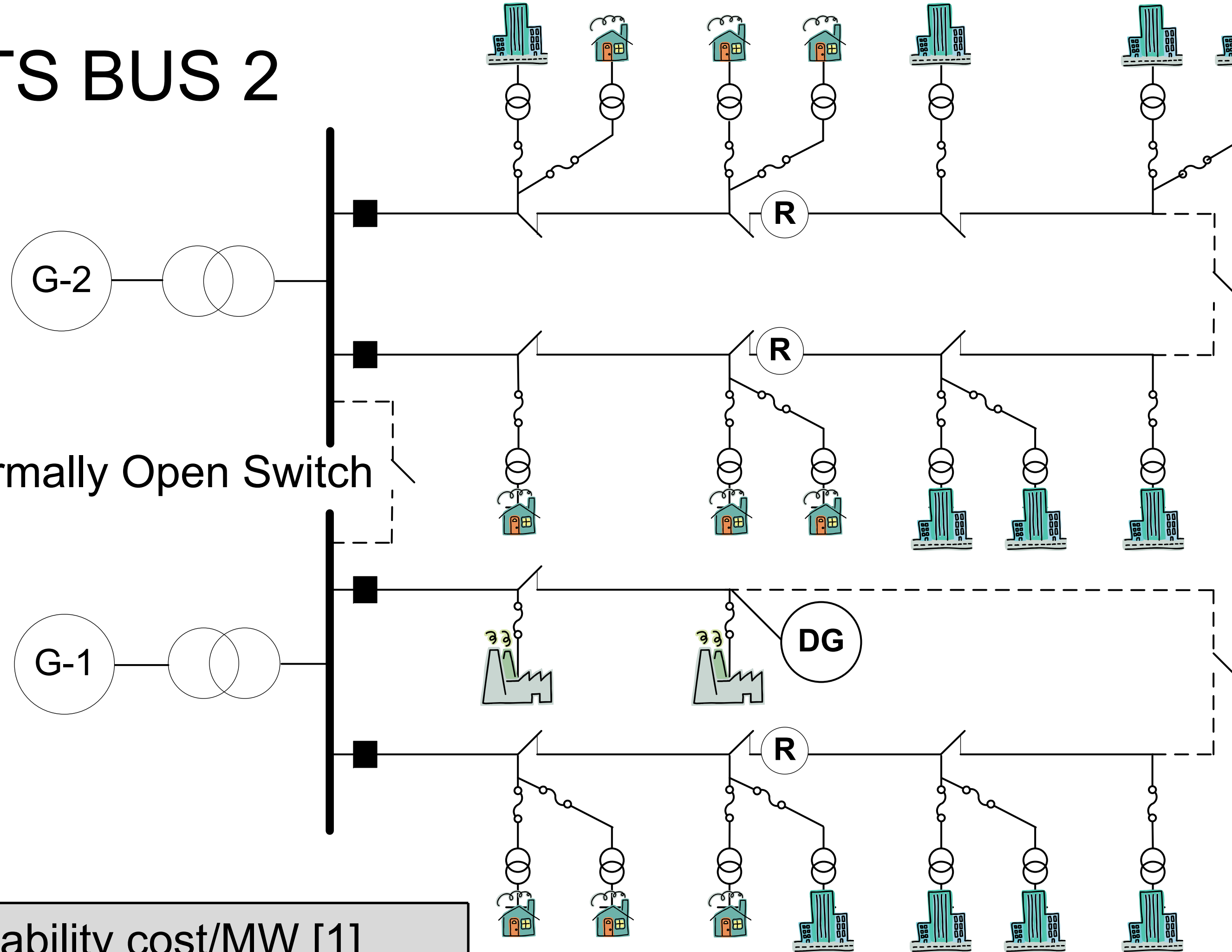
Physical efficiency due to loss delivery savings

- A small IEEE 30 bus system (50% loss reduction by placing DERs at the right locations and optimize real power generation schedules and voltage support); 1.2-1.4 efficiency estimate for this case (1.2MW of central generation can be displaced by 1MW of DGs) (Masoud Nazari, PhD EPP CMU, 2012) [3]
- Effect of losses is relatively small. Should not assume that scaling up the efficiency factor of 1.2-1.4. for the entire existing central generation
- Extensions on small real-world islands [4]
- Economic dispatch generally results in much higher losses [5]
- Physical (delivery) efficiency not aligned with economic efficiency objectives [5]

Physical efficiency due to reduced reserve requirements (reliability reserves)

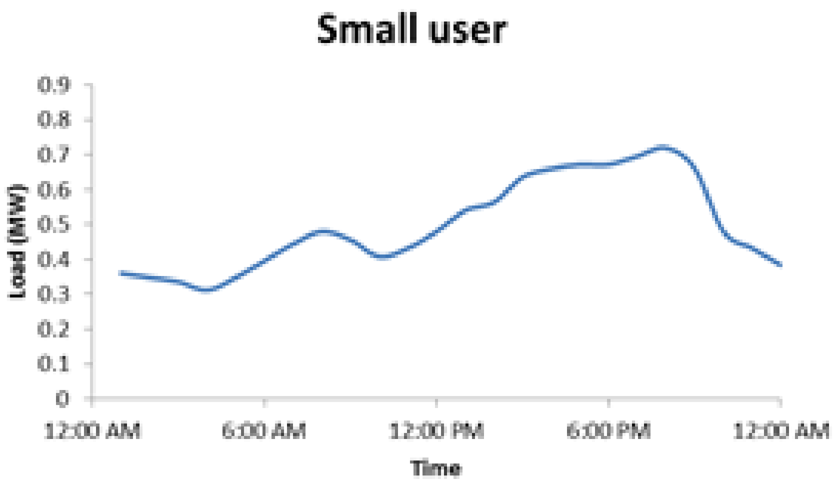
- These are key and major and should be understood when capacity markets are designed.
- Siripha Junlakarni (PhD EPP CMU, Ilic advisor)
- Prepared an important example for today's presentation; An extensive treatment of this example in [6,7].

IEEE RBTS BUS 2



Type of customers	Liability cost/MW [1]
Small user	$0
Large user	$2,000
Industrial	$21,000

Load profiles



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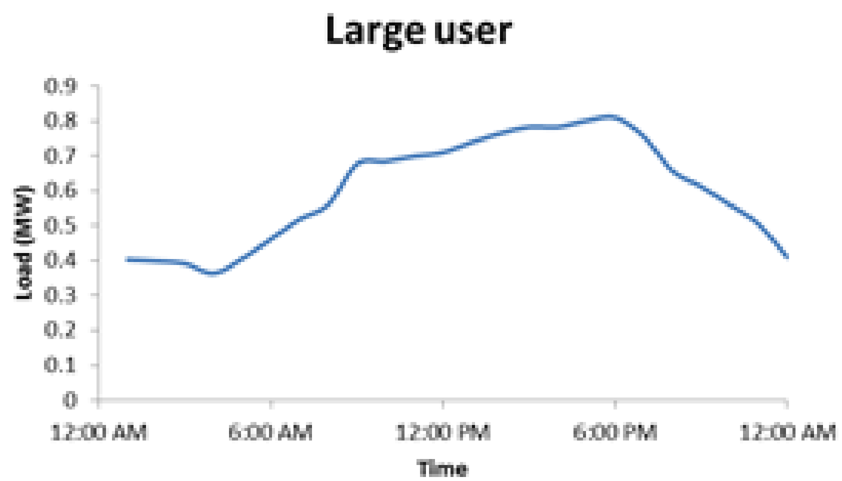

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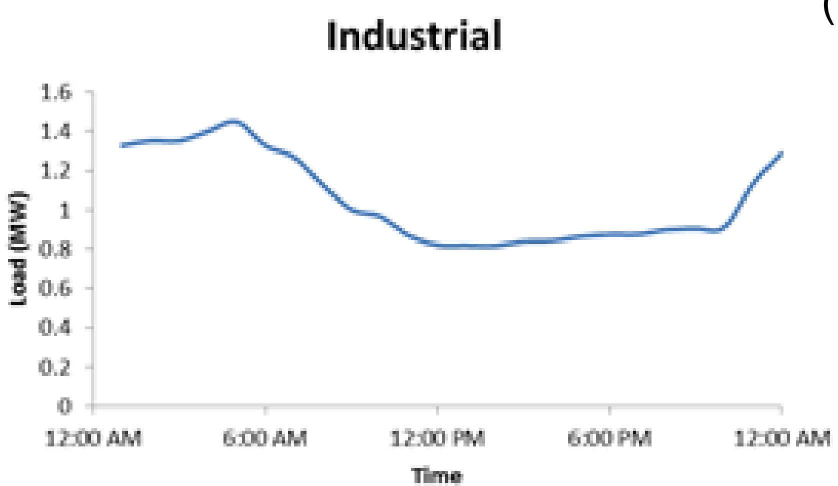

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Peak Load

	Total Peak Load (MW)	Peak Load with DER (MW)
Area-1	7.39	5.76
Area-2	10.26	4.76

	Marginal Cost
Coal	$50
Oil	$200
Wind	$0
Gas	$130
Nuclear	$10

Fault Types

- Probability of a fault occurring in the test system = 0.001

Type of Fault	Occurrence Rate
Type-1: Lose Gen-1 or Gen-2	0.10
Type-2: Lose both Gen-1 and Gen-2	0.05

Normal condition	Lose Gen-1 or Gen-2	Lose both Gen
8758.56 hr	0.934 hr	0.443 hr

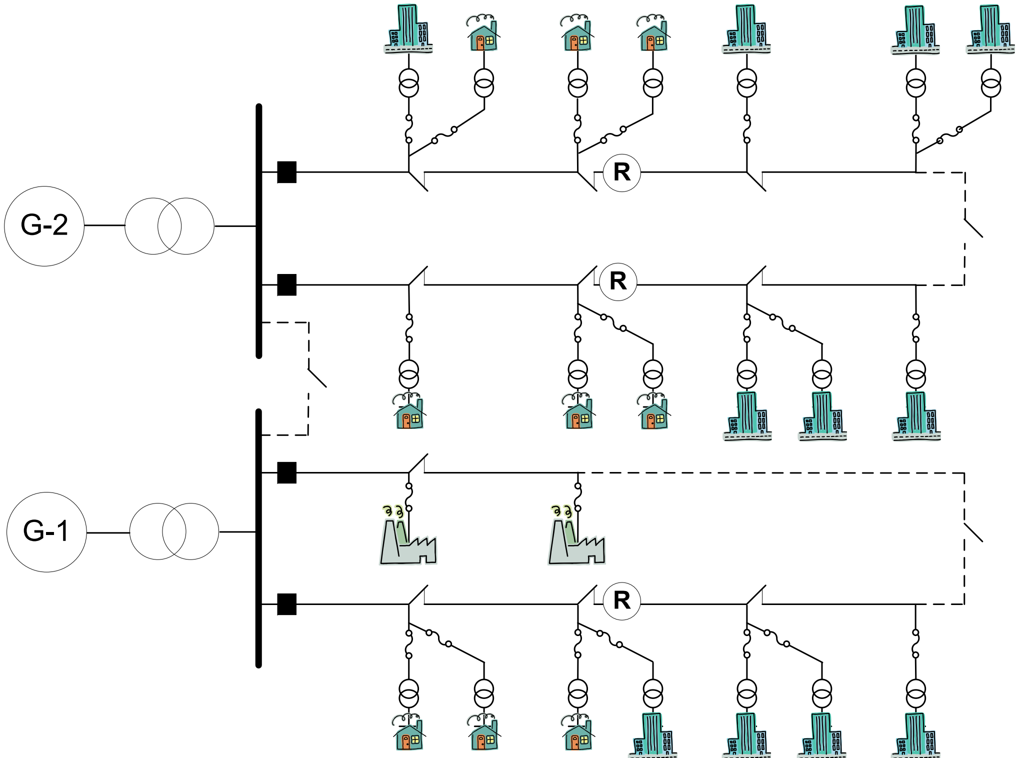
Demand Response (DR) Agreements

Small users agree to get interrupted

- Large users reduce power usage up to 20%
- Industrial users can not be interrupted (100% power supply required)

- Users participating in demand response program are willing to disconnect their loads (assuming sufficient incentives)
- Liability cost is applied when customers are not supplied load as they expect

Solution-1: Central Generation



10.26 MW

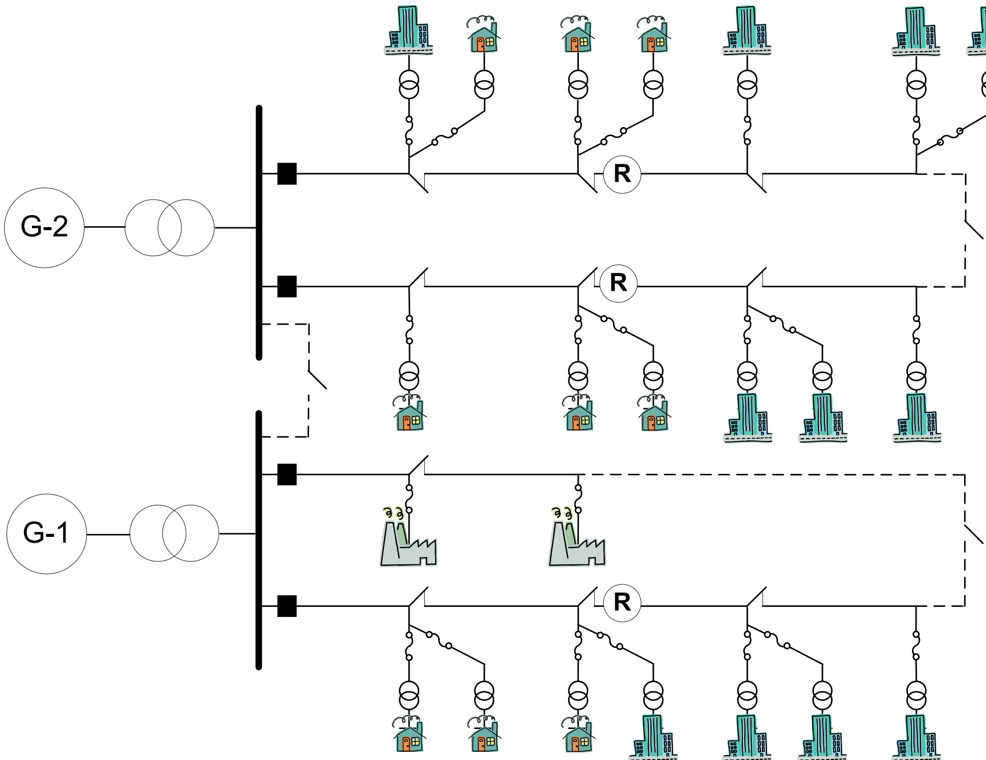
P,G2 = Peak Load,sub-2 +
Peak Load, sub-1, reserve

7.39 MW

P,G1 = Peak Load,sub-1 +
Peak Load, sub-2, reserve

Type of Fault	P-G1 (MW)	P-G2 (MW)
Type-1	17.65	17.65
	Supplied Load (MW)	Supplied Load (MW)
Type-2	0	0

Solution-2: Demand Response



- Small users agree to disconnect
- Large users agree to reduce power usage 20%

10.26 MW

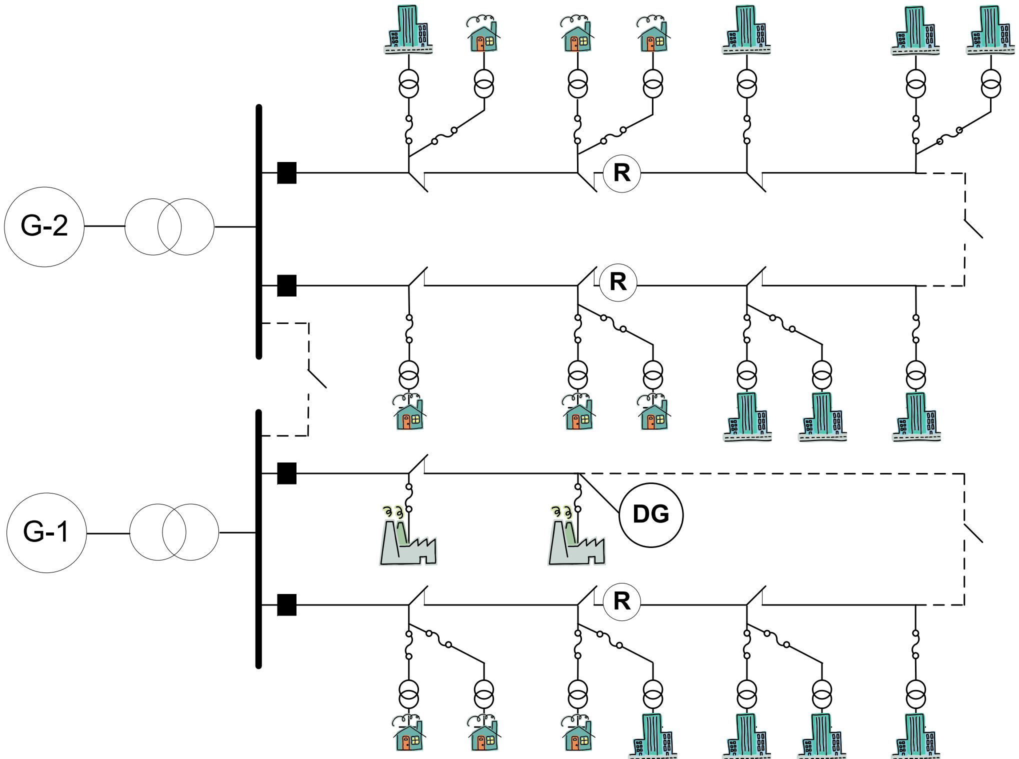
P,G2 = Peak Load,sub-2 +
0.8*(Peak Load of Large user, sub-1, reserve) + Peak Load of Industrial, sub-1, reserve

7.39 MW

P,G1 = Peak Load,sub-1 +
0.8*(Peak Load of Large user, sub- 2, reserve)

Type of Fault	P-G1 (MW)	P-G2 (MW)
Type-1	12.15	16.02
	Supplied Load (MW)	Supplied Load (MW)
Type-2	0	0

Solution-3: Limit Capacity of DG, no Demand Response



- DG capacity = 5 MW

10.26 MW

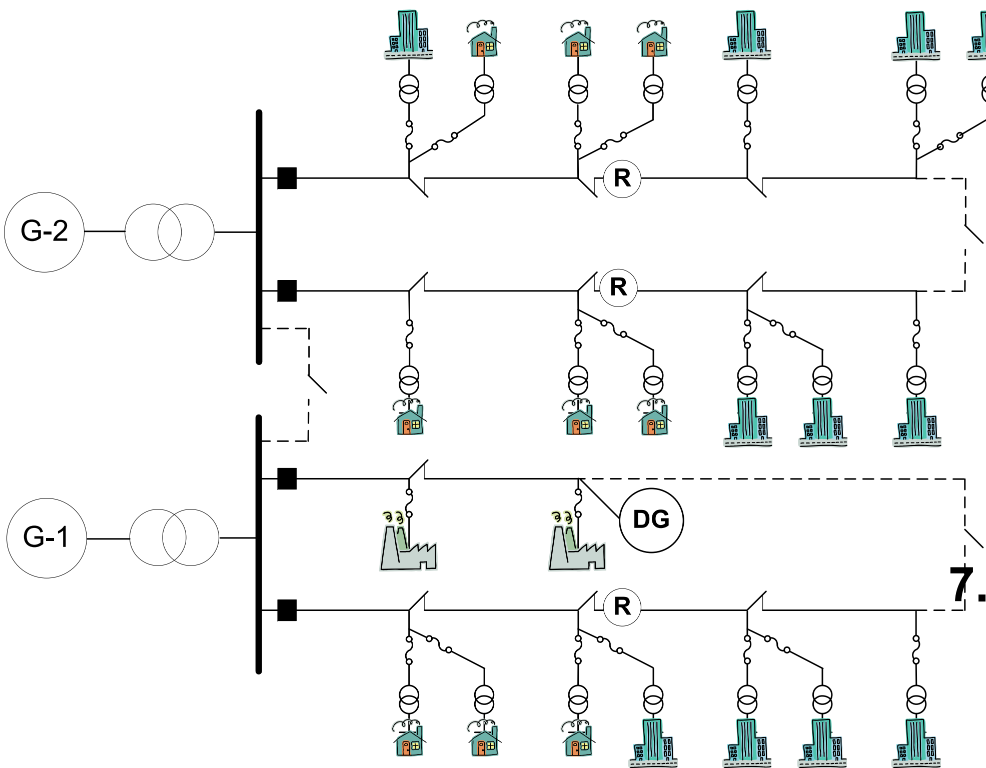
P,G2 = Peak Load,sub-2 + (Peak Load,sub-1, reserve – P,DG)

7.39 MW

P,G1 = Peak Load,sub-1 – P,DG + Peak Load, sub-2, reserve

Type of Fault	P-G1 (MW)	P-G2 (MW)
Type-1	12.65	12.65
	Supplied Load (MW)	Supplied Load (MW)
Type-2	5	0

Solution-4: Limit Capacity of DG with Demand Response



- Small users agree to disconnect
- Large users agree to reduce power usage 20%
- DG capacity = 5 MW

P-G2 = Peak Load,sub-2 + 0.8*(Peak Load of Large user, sub-1, reserve) + Peak Load of Industrial, sub-1, reserve-P,DG

7.39 MW

P-G1 = Peak Load,sub-1 – P,DG + 0.8*(Peak Load of Large user, sub- 2, reserve)

Type of Fault	P-G1 (MW)	P-G2 (MW)
Type-1	7.15	11.02
	Supplied Load (MW)	Supplied Load (MW)
Type-2	5	0

Reserve Margin and Curtailed Load

Solution-1: Central Generation vs. Solution-2: Demand Response

Area-1		Area-2	
Reserve Margin Saved (MW)	Curtailed Demand in Area-2 (MW)	Reserve Margin Saved (MW)	Curtailed Demand in area-1 (MW)
5.50	5.67	1.63	2.92

P, Gen-1, Central = 12.15 MW
P, Gen-2, Central = 16.02 MW

Reserve Margin and Curtailed Load

Solution-1: Central Generation vs
Solution-3: Limit Capacity of DG without DR

Area-1		Area-2	
Reserve Margin Saved (MW)	Curtailed Demand in Area-2 (MW)	Reserve Margin Saved (MW)	Curtailed Demand in area-1 (MW)
5.00	0	5.00	0

P, Gen-1, Central = 12.65 MW
P, Gen-2, Central = 12.65 MW
P, DG = 5 MW

Note: DG used as a power reserve

Reserve Margin and Curtailed Load

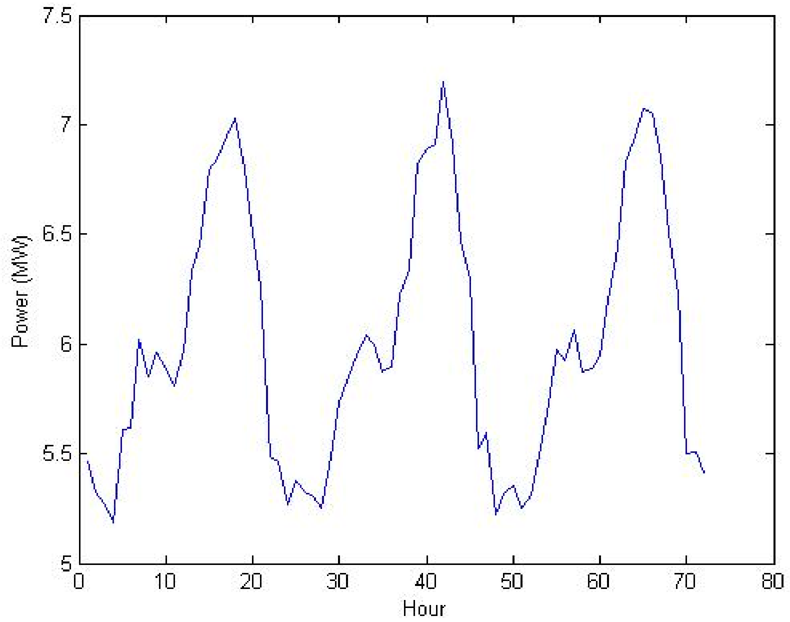
Solution-1: Central Generation VS
Solution-4: Limit Capacity of DG with DR

Area-1		Area-2	
Reserve Margin Saved (MW)	Curtailed Demand in Area-2 (MW)	Reserve Margin Saved (MW)	Curtailed Demand in area-1 (MW)
10. 50	5.67	6.63	2.92

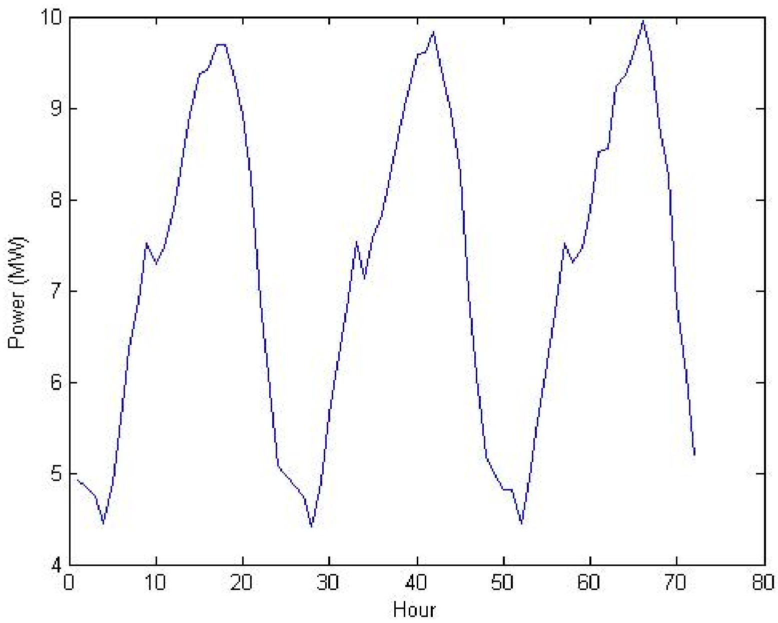
P, Gen-1, Central = 7.15 MW
P, Gen-2, Central = 11.02 MW
P,DG = 5 MW

Physical efficiency due to temporal shifts during normal operations (peak load shaving)

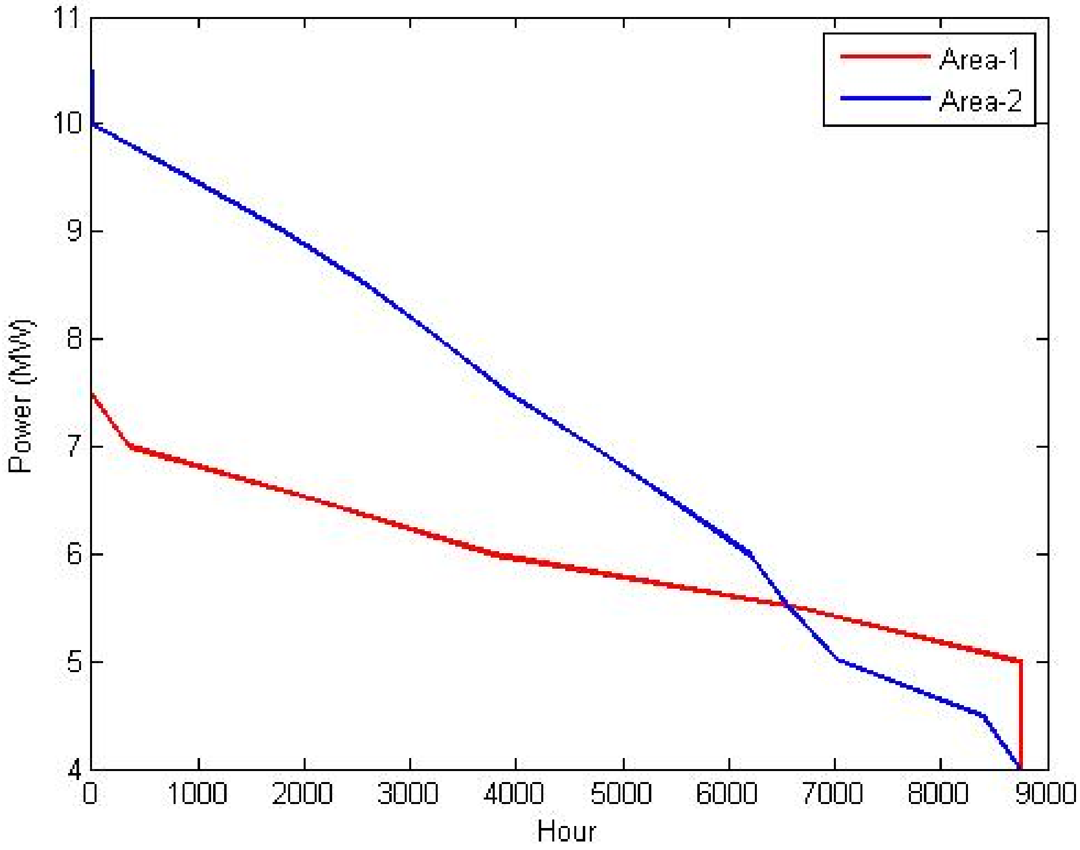
Load Profile of Area-1 for 3 days



Load Profile of Area-2 for 3 days



Load Factor of 2 Area



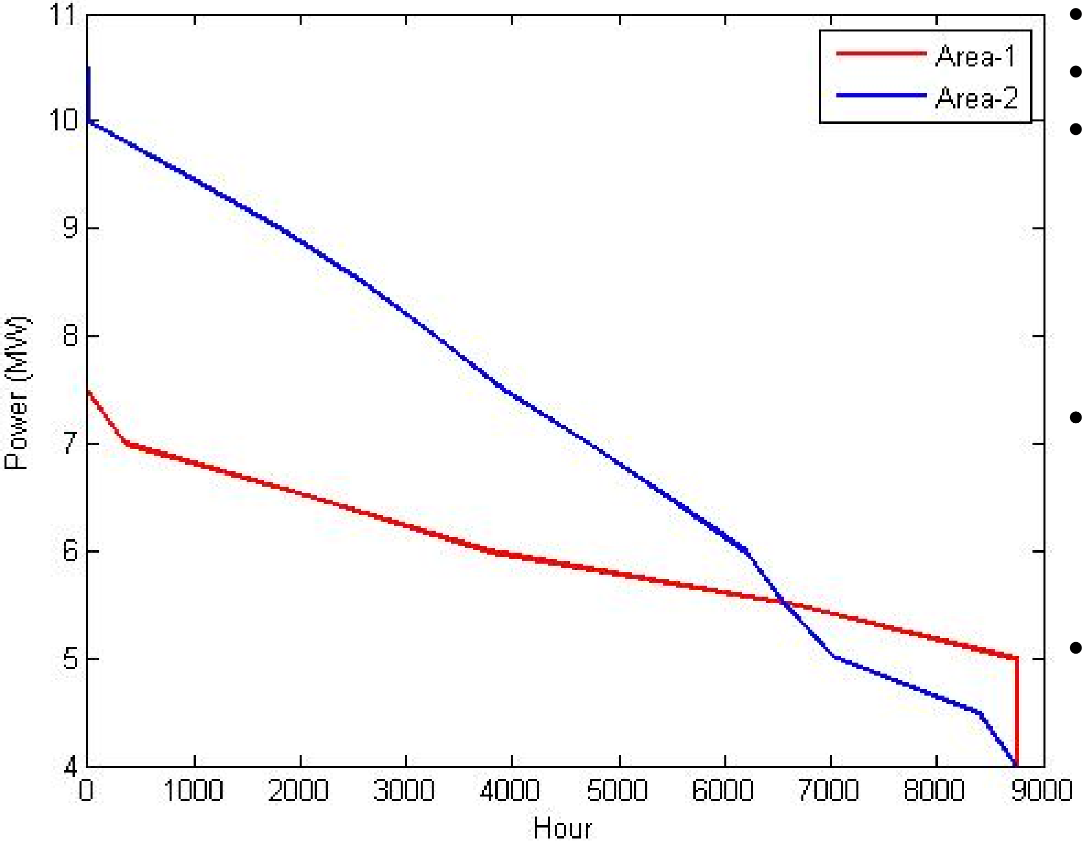
$$\text{Load Factor} = \frac{\text{Total Energy 1 year (MWh)}}{\text{Peak Load (MW)} \times 8760\text{ hr}}$$

$$\text{LF of Area 1} = \frac{52649.27}{7.39 \times 8760}$$

$$= 0.81$$

$$\text{LF of Area 2} = \frac{63044.18}{10.26 \times 8760}$$

$$= 0.70$$

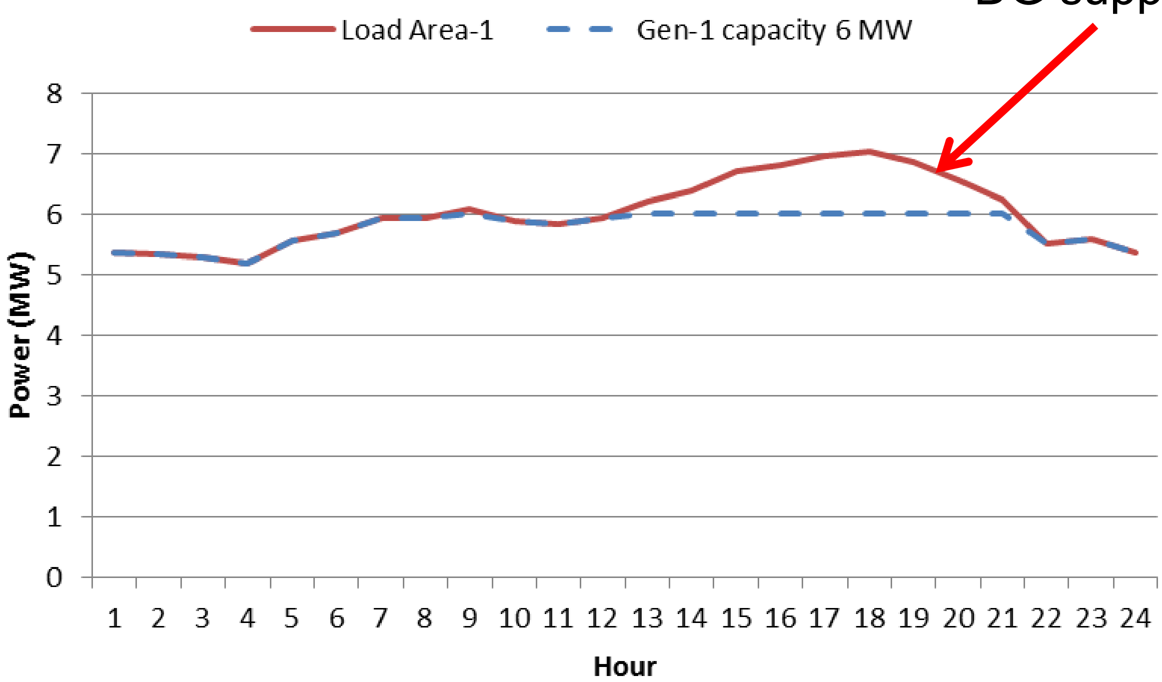


- Peak at area-1 = 7.39 MW
- Peak at area-2 = 10.26 MW
- Thus, to cover the peak demand, Gen-1 and Gen-2 will have capacity around the peak load
- Generator should has capacity to supply loads around 70 - 90% "load factor"
- Instead of using all central generation to supply the peak load, use DG to supply when peak demand occurs.
- Assume that central generation supplies 90% of energy consumption.

Central generation should have power:

- Gen-1 = 6 MW
- Gen-2 = 8 MW

DG supplies peak load



- Reduce reserve margin
- Increase efficiency of Gen-1
- This is also true for Gen-2

Economic efficiency in electricity markets

Expected Generation Cost and Liability Cost in 1 year

Central Generation
Demand Response (DR)
DG without DR
DG with DR

Gen-1	Gen-2	DG	Solution-1	Solution-2	Solution-3	Solution-4
Nuclear	Coal	Wind	$3,703,684.68	$3,702,445.84	$3,243,397.47	$3,242,158.62
Nuclear	Coal	Gas	$3,703,684.68	$3,702,445.84	$8,937,358.37	$8,936,119.53
Nuclear	Wind	Wind	$552,027.28	$550,834.49	$91,856.85	$90,664.06
Nuclear	Wind	Gas	$552,027.28	$550,834.49	$5,785,817.76	$5,784,624.97
Coal	Wind	Wind	$2,658,007.58	$2,656,743.35	$446,031.28	$444,767.05
Coal	Wind	Gas	$2,658,007.58	$2,656,743.35	$6,139,992.18	$6,138,727.96

Gen-1	Gen-2	DG	Δ(S1-S2)	Δ(S1-S3)	Δ(S1-S4)
Nuclear	Coal	Wind	$1,238.85	$460,287.22	$461,526.06
Nuclear	Coal	Gas	$1,238.85	($5,233,673.69)	($5,232,434.84)
Nuclear	Wind	Wind	$1,192.79	$460,170.43	$461,363.23
Nuclear	Wind	Gas	$1,192.79	($5,233,790.47)	($5,232,597.68)
Coal	Wind	Wind	$1,264.23	$2,211,976.31	$2,213,240.54
Coal	Wind	Gas	$1,264.23	($3,481,984.60)	($3,480,720.37)

Note: If the system has DG, DG supplies its full capacity

Not consider the lowest price of generation

Effects on Cumulative Economic Efficiency (Annual)

Gen-1	Gen-2	DG	Solution-1 Gen-1 = 17.65 MW Gen-2 = 17.65 MW	Solution-2 Gen-1 = 12.12 MW Gen-2 = 16.02 MW	Solution-3 Gen-1 = 6 MW Gen-2 = 8 MW DG = 5 MW	Solution-4 Gen-1 = 6 MW Gen-2 = 8 MW DG = 5 MW
Nuclear	Coal	Wind	\$3,703,684.68	\$3,702,445.84	\$3,243,976.50	\$3,242,355.87
Nuclear	Coal	Gas	\$3,703,684.68	\$3,702,445.84	\$4,226,268.15	\$4,224,526.29
Nuclear	Wind	Wind	\$552,027.28	\$550,834.49	\$92,461.57	\$90,864.99
Nuclear	Wind	Gas	\$552,027.28	\$550,834.49	\$1,254,666.07	\$1,252,924.21
Coal	Wind	Wind	\$2,658,007.58	\$2,656,743.35	\$626,524.78	\$624,900.61
Coal	Wind	Gas	\$2,658,007.58	\$2,656,743.35	\$3,275,305.51	\$3,273,563.65

Note: ED with expensive DG; it will be used to supply peak load

Gen-1	Gen-2	DG	Δ(S1-S2)	Δ(S1-S3)	Δ(S1-S4)
Nuclear	Coal	Wind	\$1,238.85	\$459,708.19	\$461,328.82
Nuclear	Coal	Gas	\$1,238.85	(\$522,583.47)	(\$520,841.61)
Nuclear	Wind	Wind	\$1,192.79	\$459,565.71	\$461,162.29
Nuclear	Wind	Gas	\$1,192.79	(\$702,638.79)	(\$700,896.93)
Coal	Wind	Wind	\$1,264.23	\$2,031,482.80	\$2,033,106.97
Coal	Wind	Gas	\$1,264.23	(\$617,297.92)	(\$615,556.06)

Adjust Capacity of Gen-1 and Gen-2

Gen-1	Gen-2	DG	Solution-3 Gen-1 = 8MW Gen-2 = 10 MW DG = 5 MW	Solution-4 Gen-1 = 8 MW Gen-2 = 10 MW DG = 5 MW	Δ(S1-S3)	Δ(S1-S4)
Nuclear	Coal	Wind	$3,243,385.02	$3,242,158.62	$460,299.67	$461,526.06
Nuclear	Coal	Gas	$3,682,080.39	$3,680,655.98	$21,604.30	$23,028.70
Nuclear	Wind	Wind	$91,851.71	$90,664.06	$460,175.57	$461,363.23
Nuclear	Wind	Gas	$530,498.25	$529,080.46	$21,529.03	$22,946.83
Coal	Wind	Wind	$446,005.58	$444,767.05	$2,212,002.00	$2,213,240.54
Coal	Wind	Gas	$2,636,381.27	$2,634,813.99	$21,626.31	$23,193.59

Discussion

- Solution-1: central generation
  - The system must have reserve power equal to the load in the area where power outages occur
- Solution-2: Demand response
  - Some customers are willing to disconnect themselves, not necessary to have the same reserve
  - Thus, reserve power of central generation is less than reserve power of solution-1

Discussion

- Solution-3: DG without DR
- Solution-4: DG with DR
  - Since we use DG to supply peak load, we can reduce reserve power of central generation
  - The economic outcome depends on DG O&M cost

    --If the DG O&M is lower than the O&M of central generation, these two solution are better of the solution-1 (central generation)

    --If the O&M of DG is higher than the O&M cost of central generation, DER solution is not better than solution-1

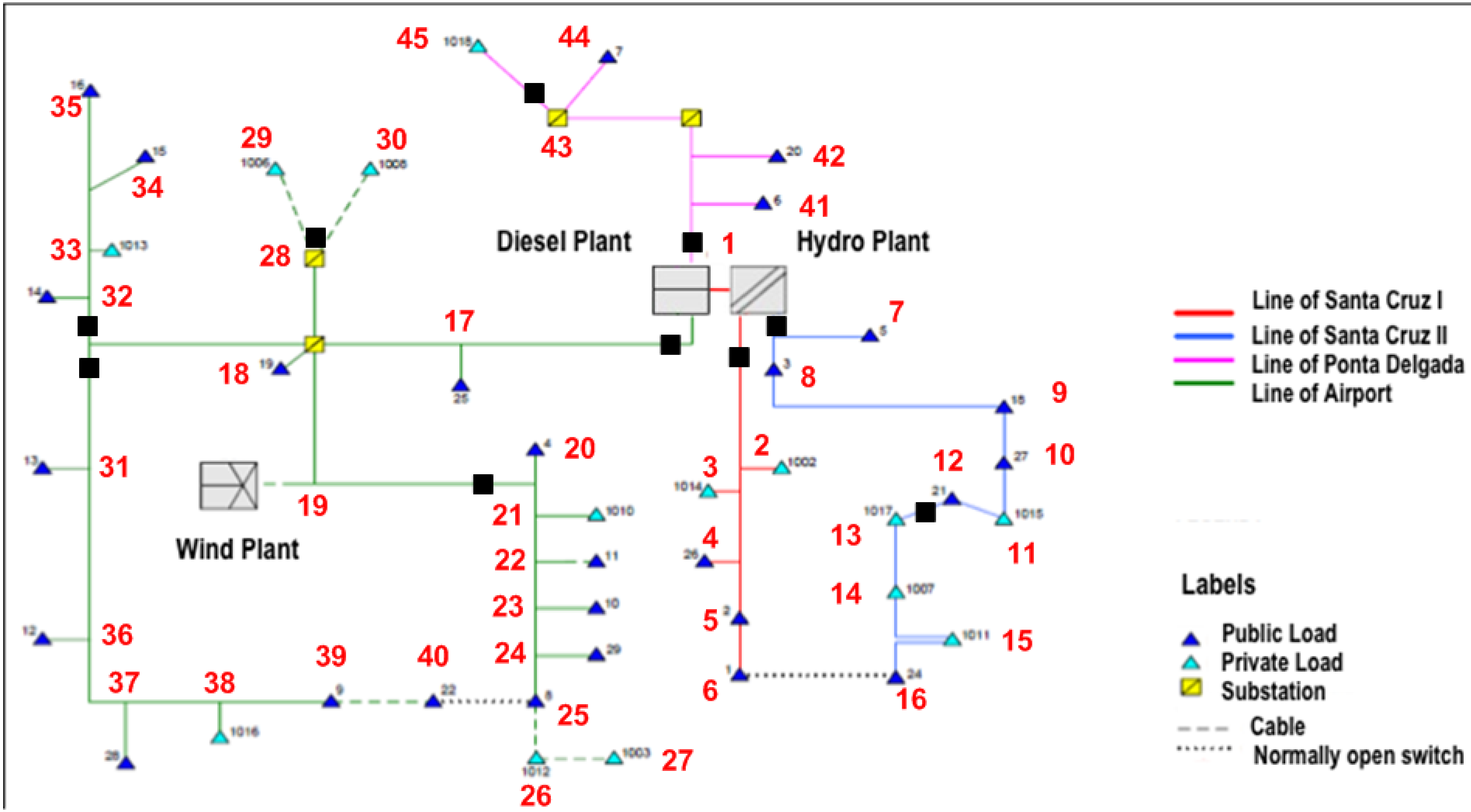
Discussion

- When reserve power of Gen-1 and Gen-2 is increased (slide as shown in Slide 20
  - The conclusions depend on DG O&M cost
    - If the O&M cost of a DG is much higher than the O&M cost of central generation, the solution-3 and 4 can be worse than the solution-1
  - Because
    - the capacity of gen-1 and gen-2 can cover peak load, no need to use DG to supply peak load
    - Gen-1 and Gen-2 have some reserve power to supply loads in another substation when losing one generation

Conclusions

- DG and DR can increase reliability of the system
  - DG effective in supplying loads when losing both generators
  - Existing capacity of generation can supply priority customers because DR disconnects and decreases some loads
- Use of DG as reserve margin depends on DG O&M cost

Designing IT infrastructure to harvest hidden efficiencies in distribution systems (Flores Island) [6]



IT-enabled reliable efficiency: Problem formulation

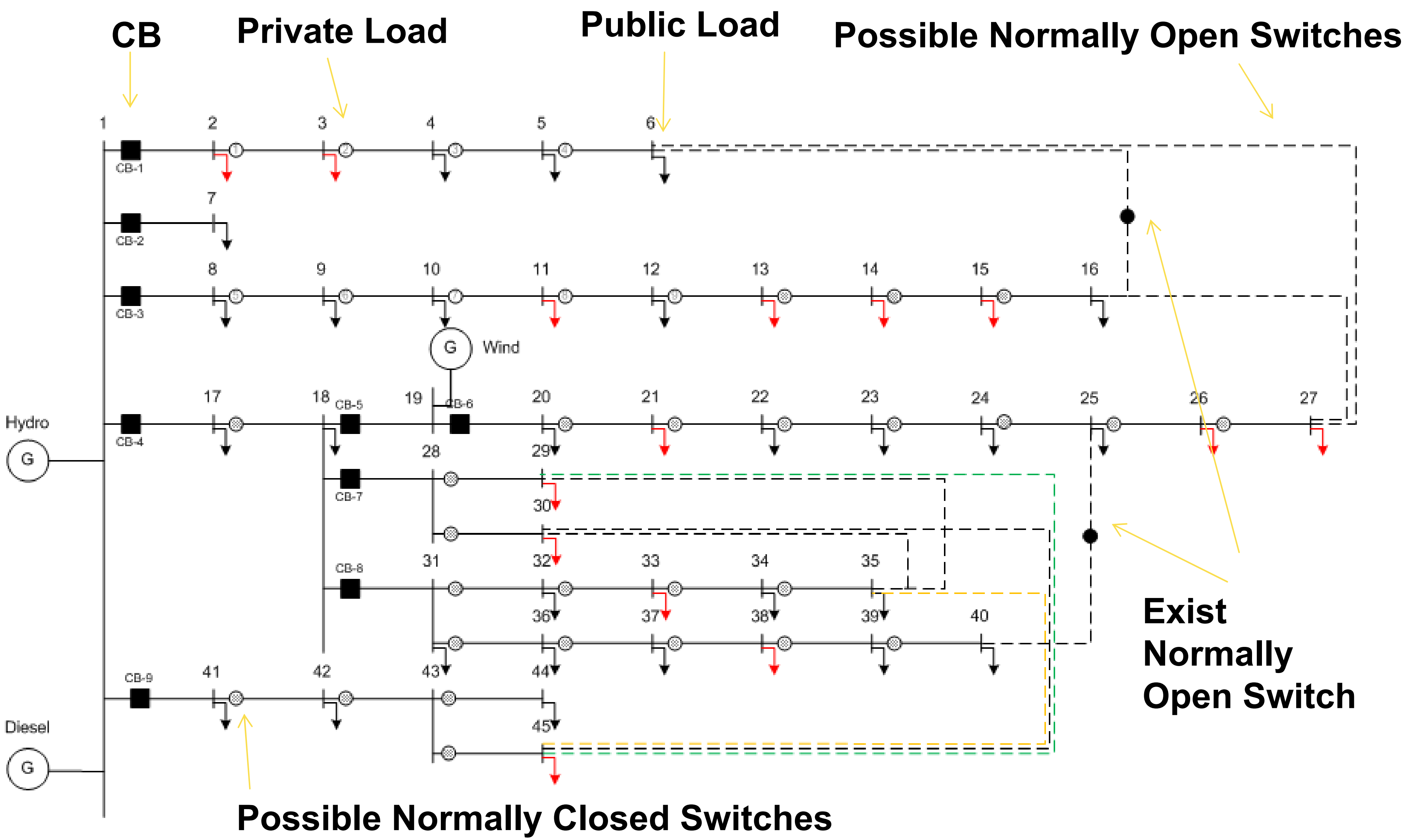
- Minimize interrupting cost of the distribution network when faults occur

$$year \times \left(\sum_{Fault=2}^{45} P_{unsupplied,L,i} \times IC_{L,i} \right) + (No.of\ Switch \times C_{Switch})$$

  - $P_{unsupplied,L,i}$: Unsupplied Load *i*
  - $IC_{L,i}$: Interrupting cost of Load *I*
  - C_{Switch}: Cost of switch ($5,000)
  - $year$: Planning period (no. of year)

Note:

- This equation does not reflect the reality of planning
- Assumption about interrupting cost (the 1st term in eq)
  - A fault occurs at each bus (bus 2 to bus 45)
  - When a fault occurs , customers will be supplied power for 1 hr
  - Assume that there will be 44 faults occur (bus 2 to bus 45) in 1 year
- We can roughly estimate the interrupting cost for each year


CB
Private Load
Public Load
Possible Normally Open Switches
Exist Normally Open Switch
Possible Normally Closed Switches
CB-1
CB-2
CB-3
CB-4
CB-5
CB-6
CB-7
CB-8
CB-9
Hydro
Diesel
Wind
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Generation in Flores

- Diesel
  - Cost = $180 ($50), Capacity = 2.5 MW
- Hydro
  - Cost = $88 ($9), Capacity = 1.5 MW
- Wind (DG)
  - Cost = $87 ($5), Capacity = 0.6 MW

Load

- Total load
  - 1.9 MW (Snap shot)
- Customer type
  - Private Load
    - Interruption cost = $2,100 /kWh
    - willing to pay for high reliability
  - Public Load
    - Interruption cost = $0 /kWh

Switch

- 2 Normally open switches in the system
- No Normally closed switch

- IT challenge: Find location of NCS and NOS

Economic dispatch

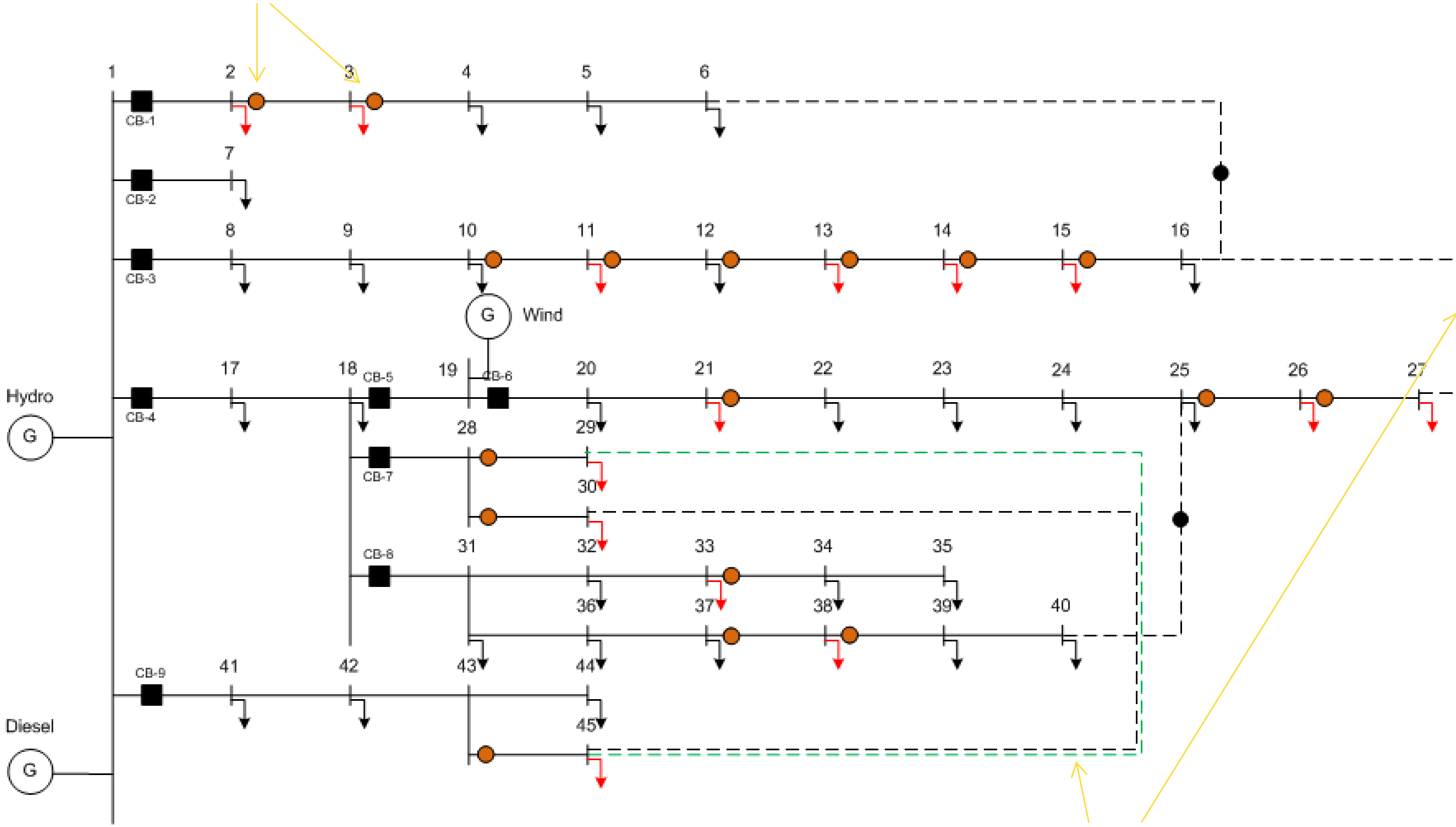
- Assume:
  - All generations are available to supply power (consider only cost of generation)
  - Power from hydro and wind is available whenever customers want power
- Order of Gen to supply load
  - Wind: Capacity = 0.6 MW, $87
  - Hydro: Capacity = 1.5 MW, $88
  - Diesel: Capacity = 2.5 MW, $180

Preliminary Results

- The original system
  - Interrupting cost = $67,709/year
- The planning period = 10 years

	Original system	Modified system
No. of installed switches	0	20
Switch cost	0	20x$5,000 = $100,000
Interrupting cost	$67,709/year x 10 year = $677,090	$16,585/year x 10 year = $165,850
Total cost	$677,090	$265,850

Location of installed NCS



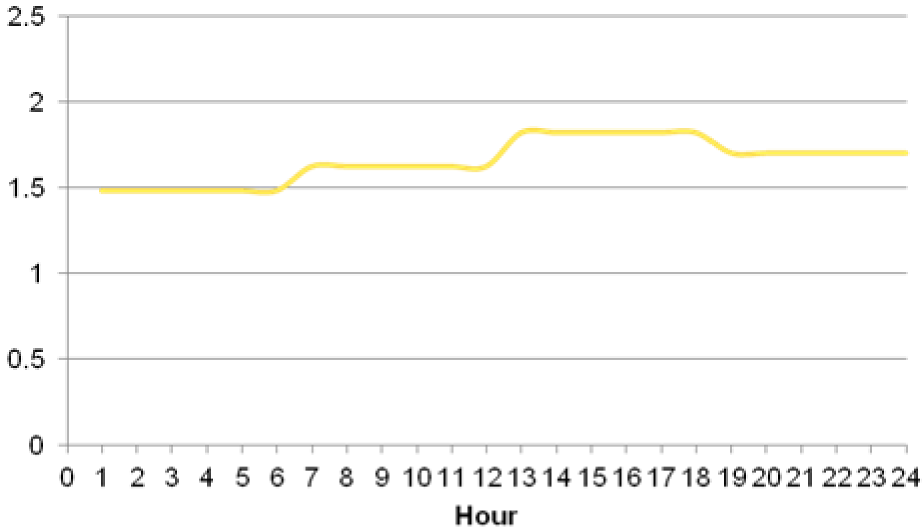
Location of installed NOS

Generation Cost

- Diesel
  - Cost = $180
- Hydro
  - Cost = $88
- Wind
  - Cost = $87
- Gas
  - Cost = $130

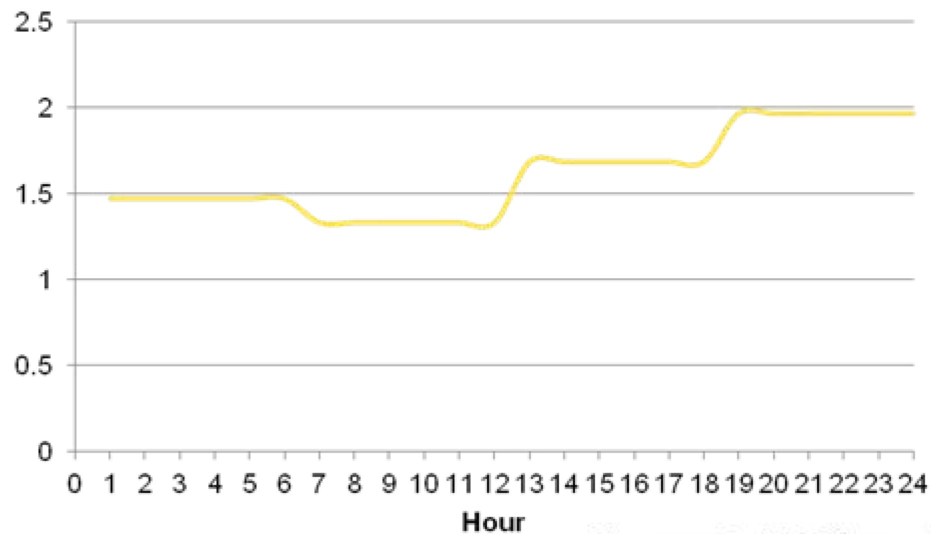
Load

Load profile for summer (5 months)



Assume
•load profile will repeat in each day
•In 1 year, 5 months for summer and 7 months for winter

Load profile for winter (7 months)



	Summer	Winter
Average Load	1.66 MW	1.62 MW
Peak Load	1.82 MW	1.97 MW

Solution

- Solution-1: Central Generation
- Solution-2: Central Generation <u>with</u> only Demand Response
  - DR: Disconnect all public customers
    Private customers decrease their usage 20%
- Solution-3: DG <u>without</u> Demand Response
- Solution-4: DG <u>with</u> Demand Response

  - Note: Solution-3 and Solution-4
  - Using NCS/NOS to reconfigure the system to supply priority customers

Generation reserve estimate

Solution-1	Amount
Total energy in 1 year	14,303.51 MWh
Gen with capacity of 2 MW	2 MW*8,760 hr = 17,520 MWh

- Gen must cover peak load (1.97 MW)
- Without DG, Gen-1 and Gen-2 must have sufficient reserve power to supply all customers when losing Gen-1 or Gen-2

Solution-2	Amount
Total Load with DR in 1 year	4,512.047 MWh
Peak load in normal condition	1.97 MW
Peak load when applying DR	0.62 MW

- In normal condition, the total capacity of Gen-1 and Gen-2 must cover peak load
- Demand Respond will help reduce energy usage when losing Gen-1 or Gen-2
- Each Gen must cover peak load of applying DR

Generation reserve estimate

Solution-3	Amount
DG with capacity of 0.7 MW	0.7 MW*8,760 hr = 6,132 MWh
Gen with capacity of 1.3 MW	1.3 MW*8,760 hr = 11,388 MWh

- Capacity of DG must be 0.7 MW to cover peak load when applying DR
- When losing Gen-1 or Gen-2, capacity of Gen and DG must cover peak load (1.97 MW)

- Solution-4:
  - Capacity of Gens and DG is the same as that capacity in Solution-3

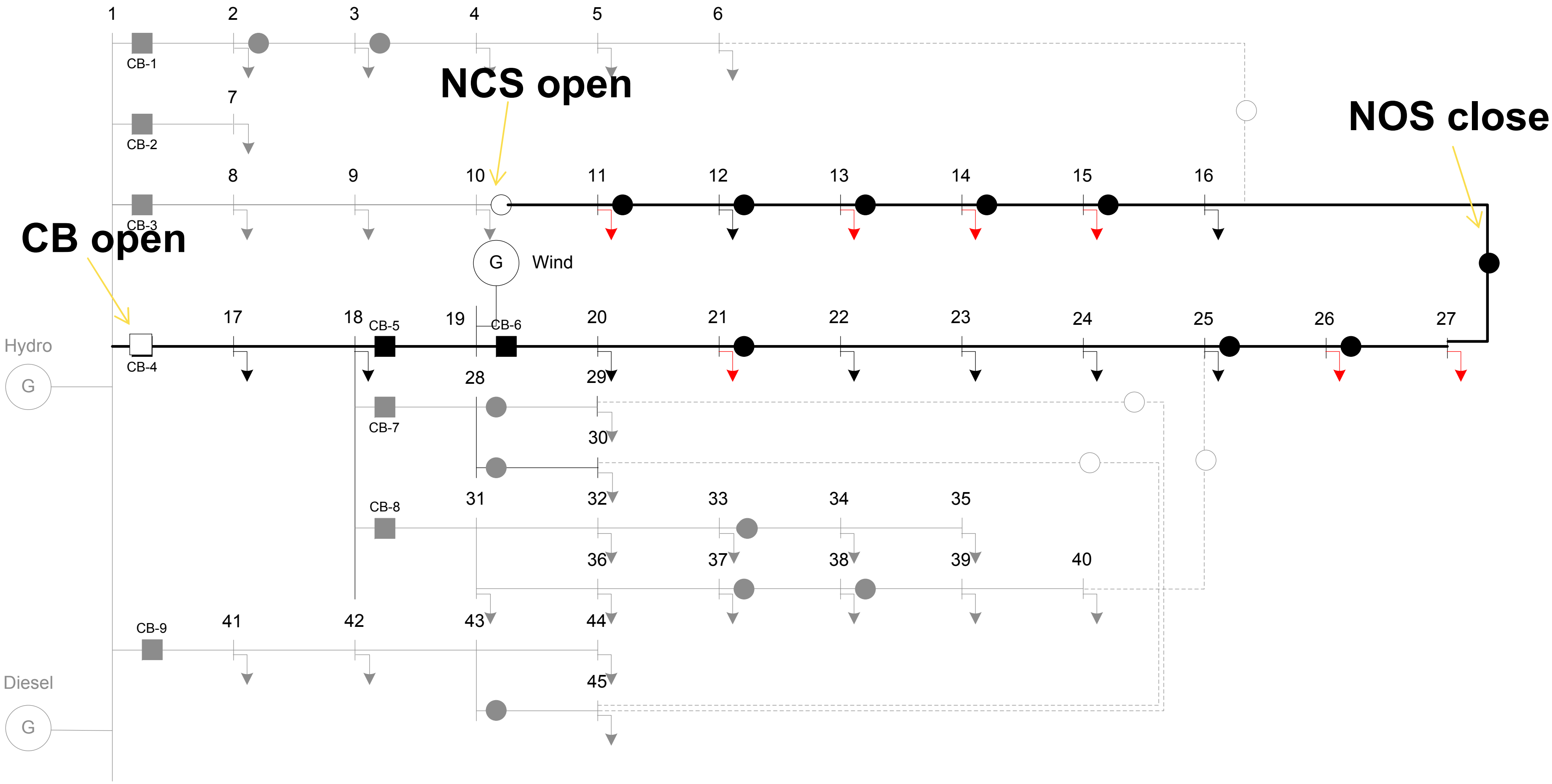
Expected Generation cost and Liability Cost in 1 year

Gen-1	Gen-2	DG	Solution-1 Gen-1 = 2 MW Gen-2 = 2 MW	Solution-2 Gen-1 = 1.7 MW Gen-2 = 1 MW	Solution-3 Gen-1 = 1.3 MW Gen-2 = 1.3 MW DG = 0.7 MW	Solution-4 Gen-1 = 1.3 MW Gen-2 = 1.3 MW DG = 0.7 MW
Hydro	Diesel	Wind	$1,259,028.02	$1,768,726.16	$1,252,576.69	$1,252,433.22
Hydro	Diesel	Gas	$1,259,028.02	$1,768,726.16	$1,381,173.36	$1,381,016.04
Hydro	Hydro	Wind	$1,258,957.85	$1,258,784.61	$1,252,536.60	$1,252,433.22
Hydro	Hydro	Gas	$1,258,957.85	$1,258,784.61	$1,258,694.65	$1,258,574.52
Diesel	Diesel	Wind	$2,574,805.33	$2,574,536.02	$2,004,272.51	$2,004,088.96
Diesel	Diesel	Gas	$2,574,805.33	$2,574,536.02	$2,267,946.70	$2,267,752.19

Note: consider economic dispatch DG supplies peak load

Gen-1	Gen-2	DG	Δ(S1-S2)	Δ(S1-S3)	Δ(S1-S4)
Hydro	Diesel	Wind	($509,698.14)	$6,451.33	$6,594.79
Hydro	Diesel	Gas	($509,698.14)	($122,145.34)	($121,988.02)
Hydro	Hydro	Wind	$173.24	$6,421.25	$6,524.62
Hydro	Hydro	Gas	$173.24	$263.20	$383.33
Diesel	Diesel	Wind	$269.31	$570,532.82	$570,716.38
Diesel	Diesel	Gas	$269.31	$306,858.63	$307,053.14

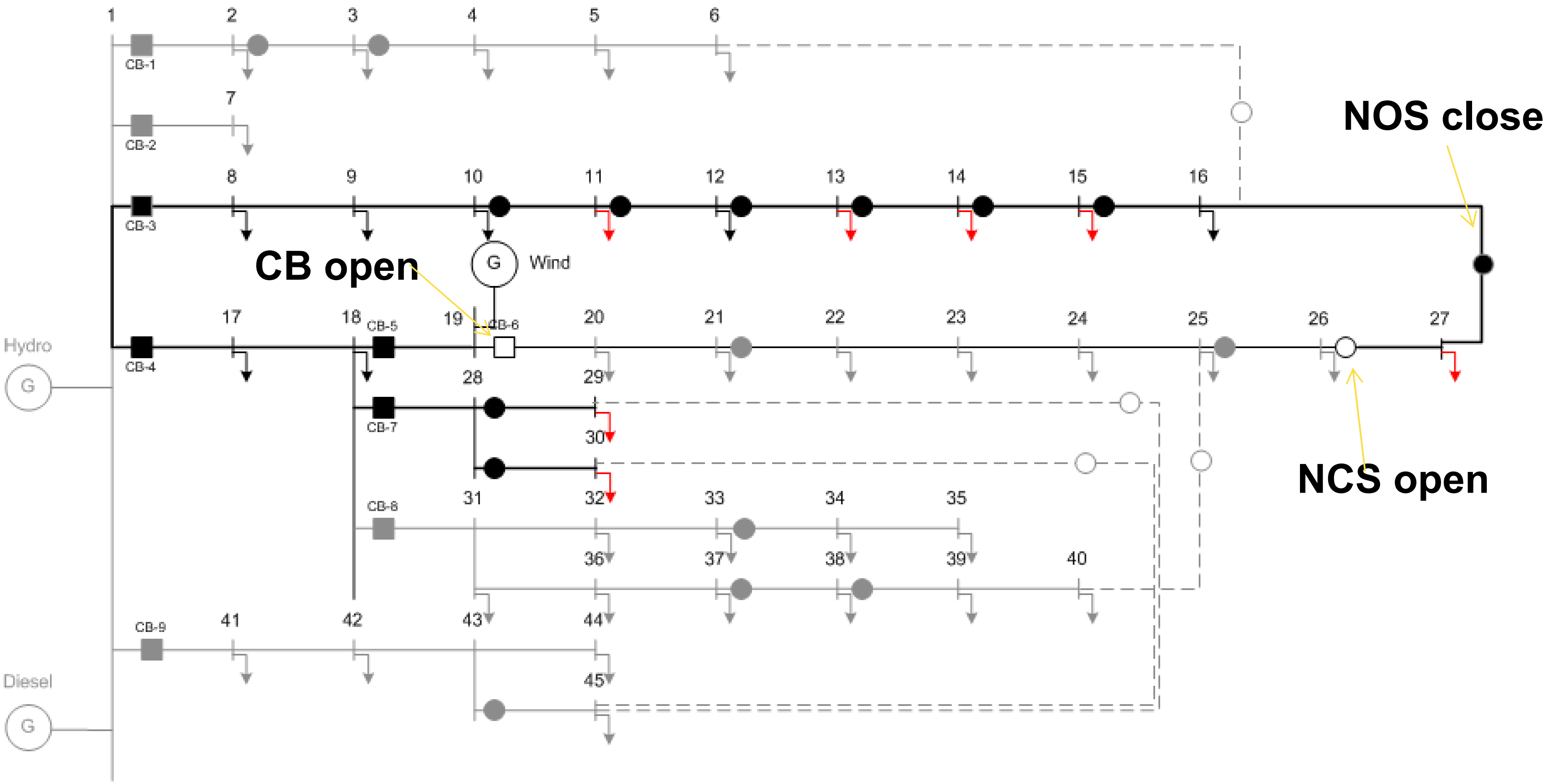
Summer load profile for 1 hr



DG capacity = 0.6 MW

Total supplied load = 0.598 MW, Interrupting cost for 1 hr = $495

Winter load profile for 1 hr



DG capacity = 0.6 MW

Total supplied load = 0.555 MW, Interrupting cost for 1 hr = $525

Solution 3 (without DR) vs Solution 4 (with DR)

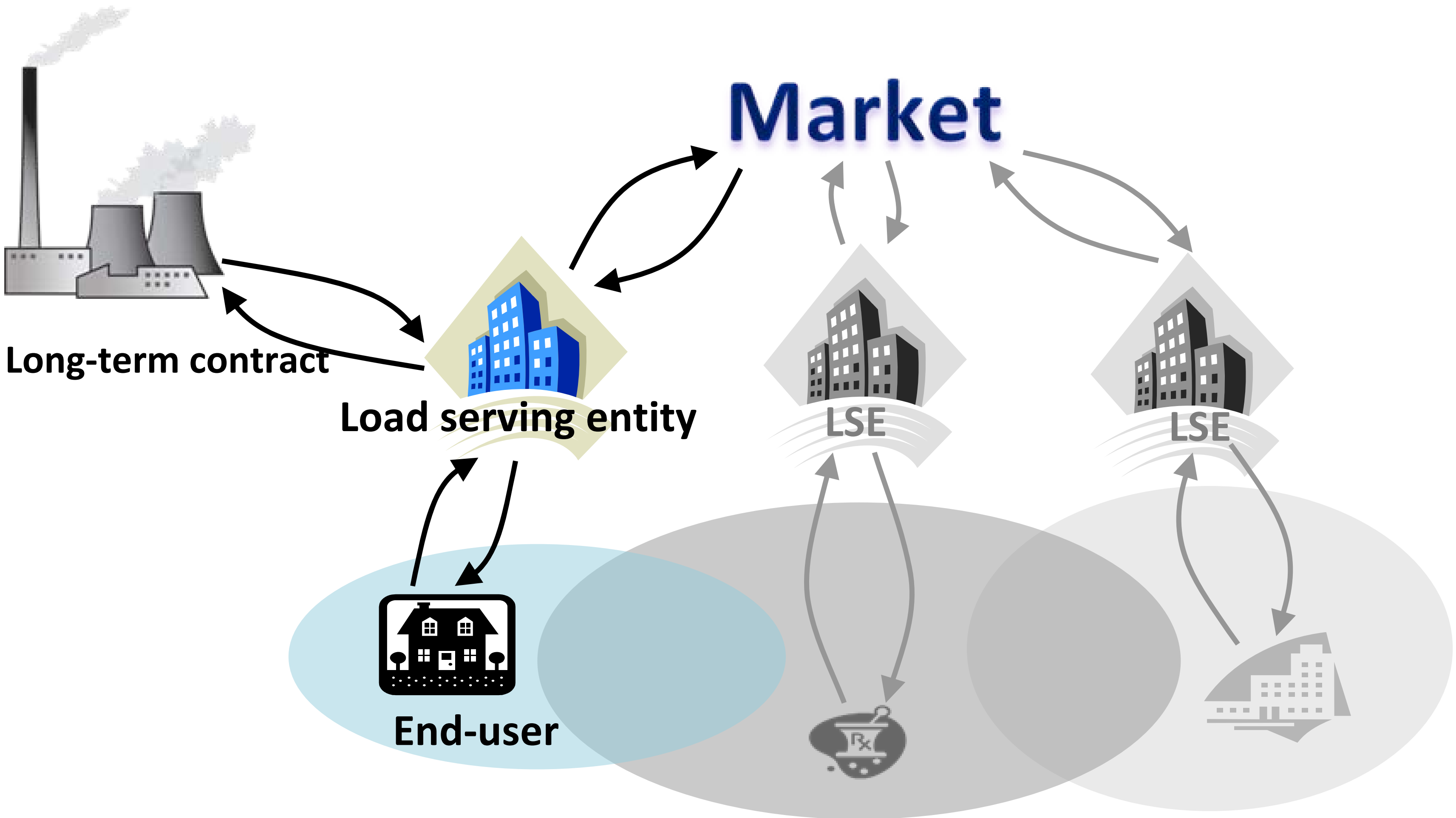
- Solution-3 has interrupting cost from disconnecting some private customers
- However, for solution-4, customers reduce their energy usage according to DR. Thus, there is no interrupting cost.
- The results from sol-3 and sol-4 are almost the same
  - Since we assume that public customers will be disconnected while private customers will reduce their energy usage for 20%
  - This DR assumption is similar to using reconfiguration to supply priority customers
  - May need to adjust the new percentage of energy usage for public and private customers
  - Then customers would still have energy to use although the amount of energy is less than energy that they expect.

Next algorithmic improvements

- Should be long term planning
  - Depend on the contract of reliability insurance
  - 5-10 years (Need to vary this parameter)
- Switch cost is capital cost -> discount rate
- Interrupting cost is considered as operating cost -> discount rate
- Improve the assumption of fault
  - Make it more realistic -> Need old reliability data of the system

Designing market rules to harvest hidden efficiencies

Key role of aggregators to account for the effects of DERs
in distributions systems on whole-sale markets Adaptive Load Management (ALM) [9-11]



Power plant drawing by Catherine Collier, Integration and Application Network, University of Maryland Center for Environmental Science (ian.umces.edu/imagelibrary/)

Concluding remarks

- Tradeoffs defined by the system users, not by the top-down hard constraints.
- DERs need to provide info about their willingness to participate in efficient markets (loss reduction, load factor increase, reserve reduction; SW maximization)
- Very careful definition of long-term economic efficiency for reliable service needed
- Potential for enhancing efficiency at differentiated reliability large given flexibility and distributed nature of DERs
- Key role of aggregators to enable harvesting distribution system level efficiency by the wholesale electricity markets
- IT-enabled infrastructure for enabling differentiated reliability of service at value possible; real opportunity [,6,7,8]

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