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Edward J. Bloustein School of Planning and Public Policy

Analyzing the Reliability and Resiliency of New Jersey's Urban Energy Systems in Response to Climate Change

DIMACS/CCICADA Workshop on Urban Planning for Climate Events
September 23-24, 2013

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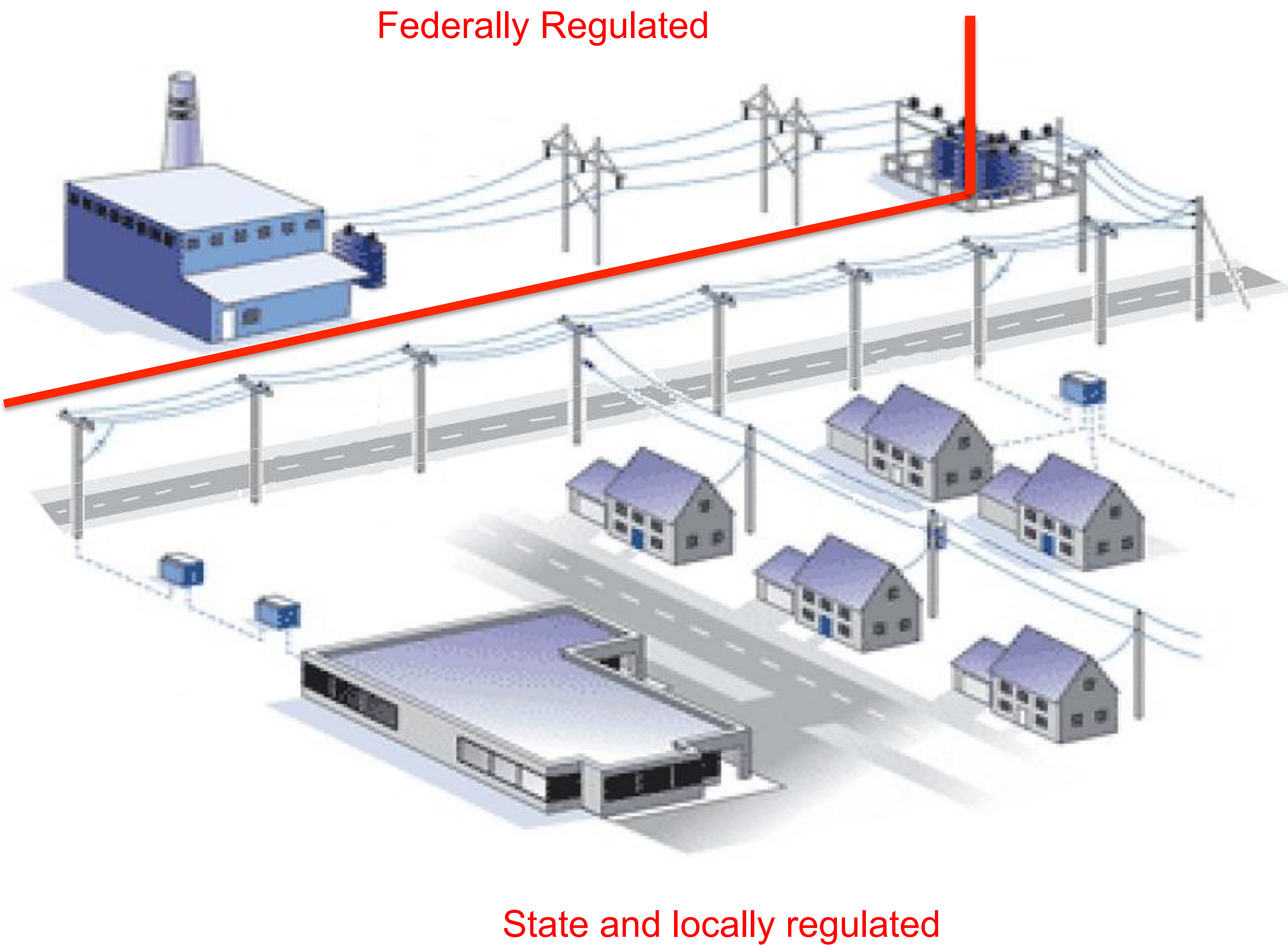
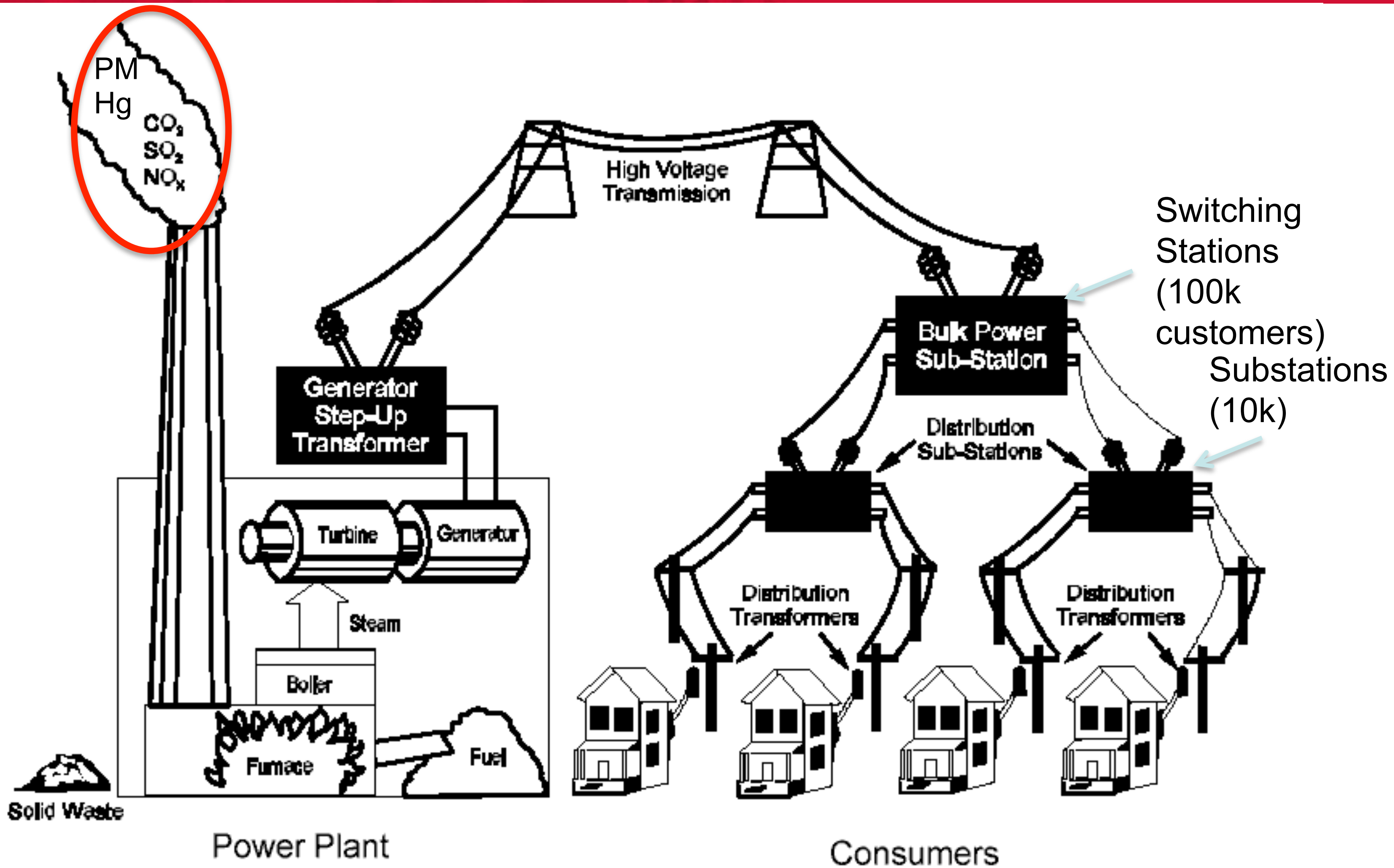
Rutgers, The State University of New Jersey


Lost.

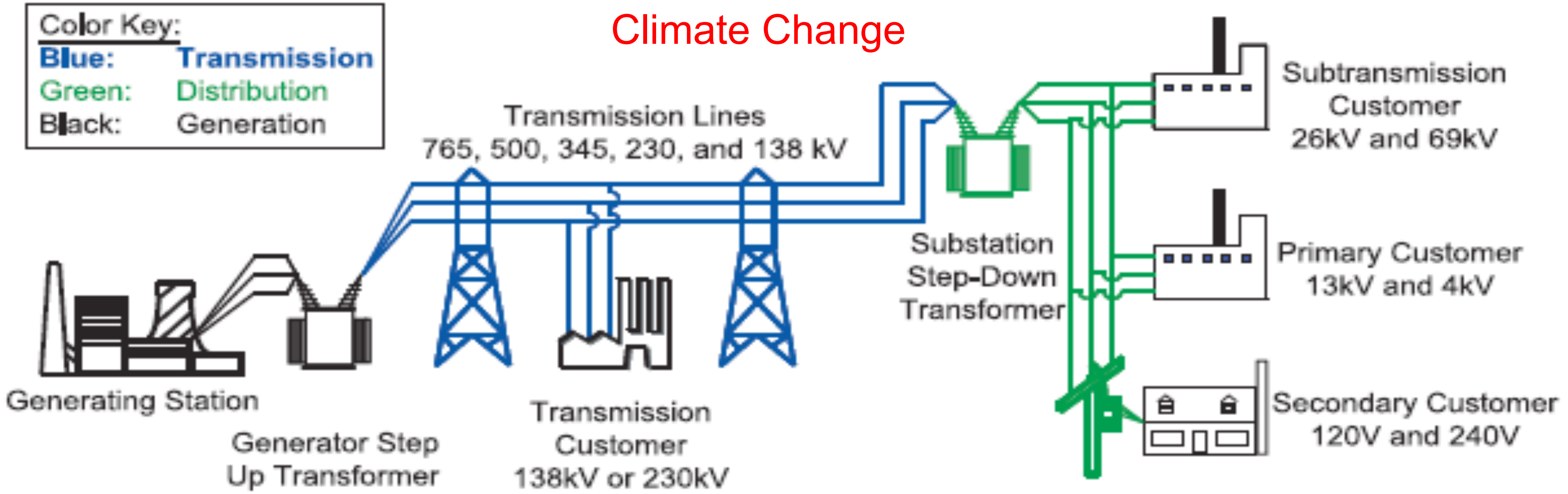

Federally Regulated
State and locally regulated


Distribution Transformers
Service lines



PM
Hg
CO_2
SO_2
NO_x
High Voltage Transmission
Switching Stations (100k customers)
Substations (10k)
Bulk Power Sub-Station
Generator Step-Up Transformer
Distribution Sub-Stations
Turbine
Generator
Steam
Boiler
Furnace
Fuel
Solid Waste
Distribution Transformers
Distribution Transformers
Power Plant
Consumers

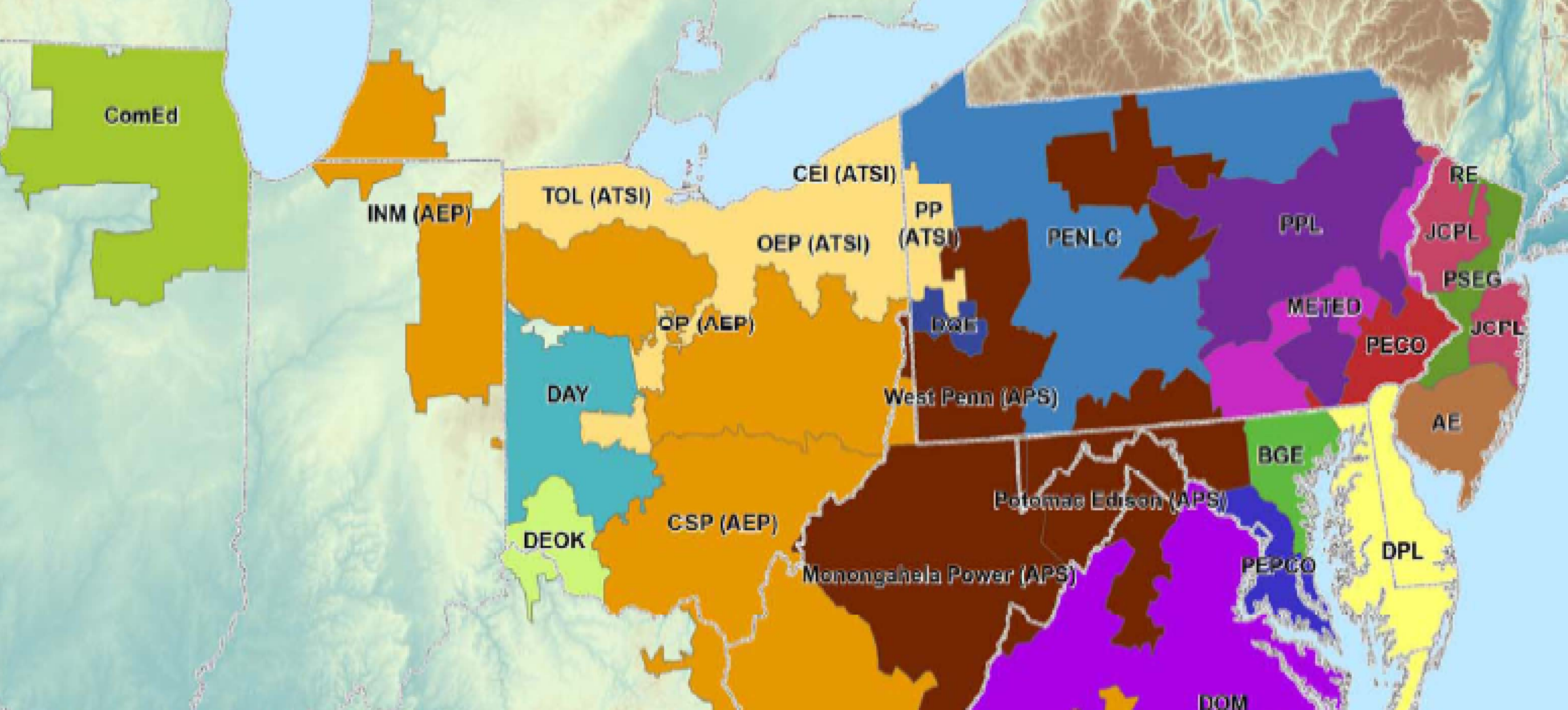
Climate Change



Increasing Temperatures

Increasing Storms and Rising Sea Levels

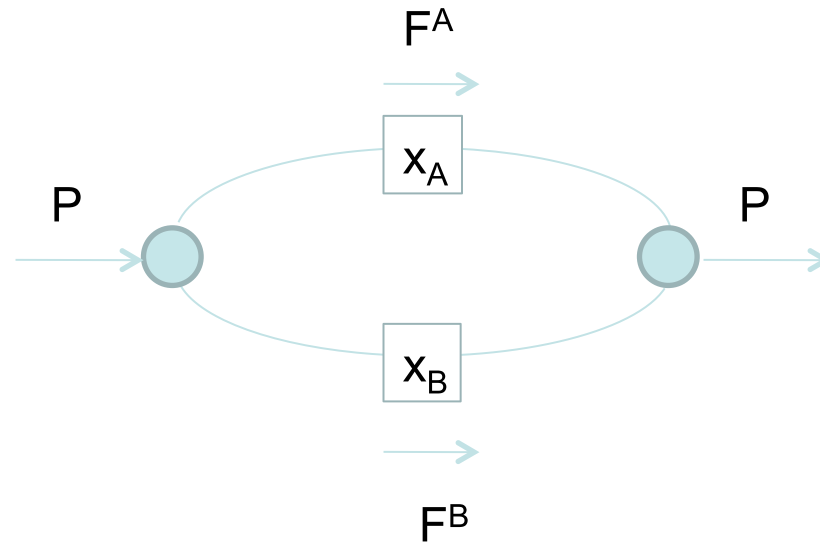
If the New Jersey economy continues to shift towards commercial and residential load, the peak load problem gets worse



PJM Interconnection (RTO/ISO)

- Regulated by the Federal Government
- Administers wholesale electricity markets
- Operates its portion of the grid
- Part of the Eastern Interconnection

- The power transfer distribution factors (PTDF) are determined by Kirchoff's Current and Voltage Laws (KCL & KVL)
- Ignoring reactive power and losses and assuming that resistance (r) << reactance (x):



$F^A = x_B/(x_A + x_B)*P$

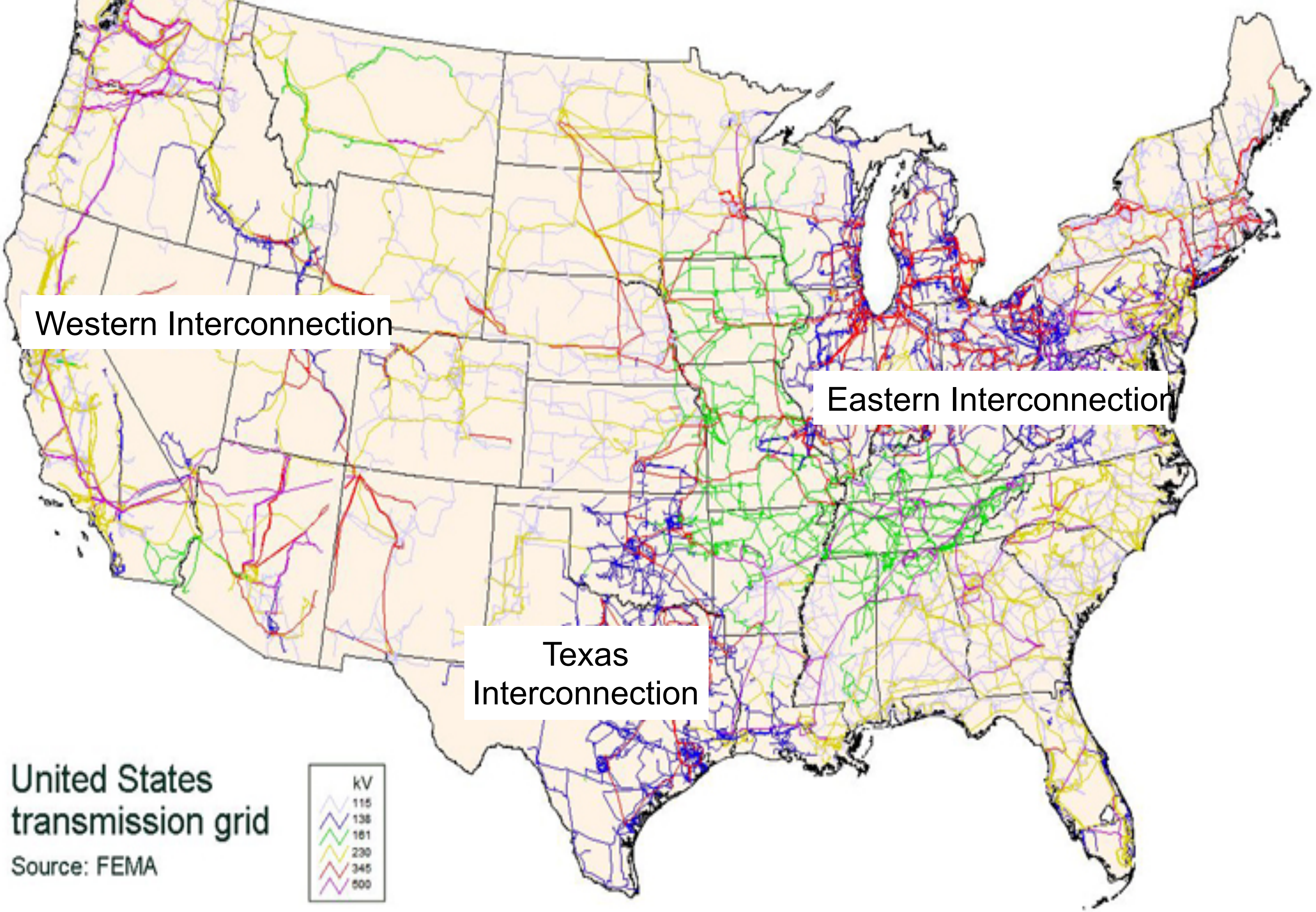
$F^B = x_A/(x_A + x_B)*P$

Z = r + jx, where Z is impedance, r is resistance and x is reactance

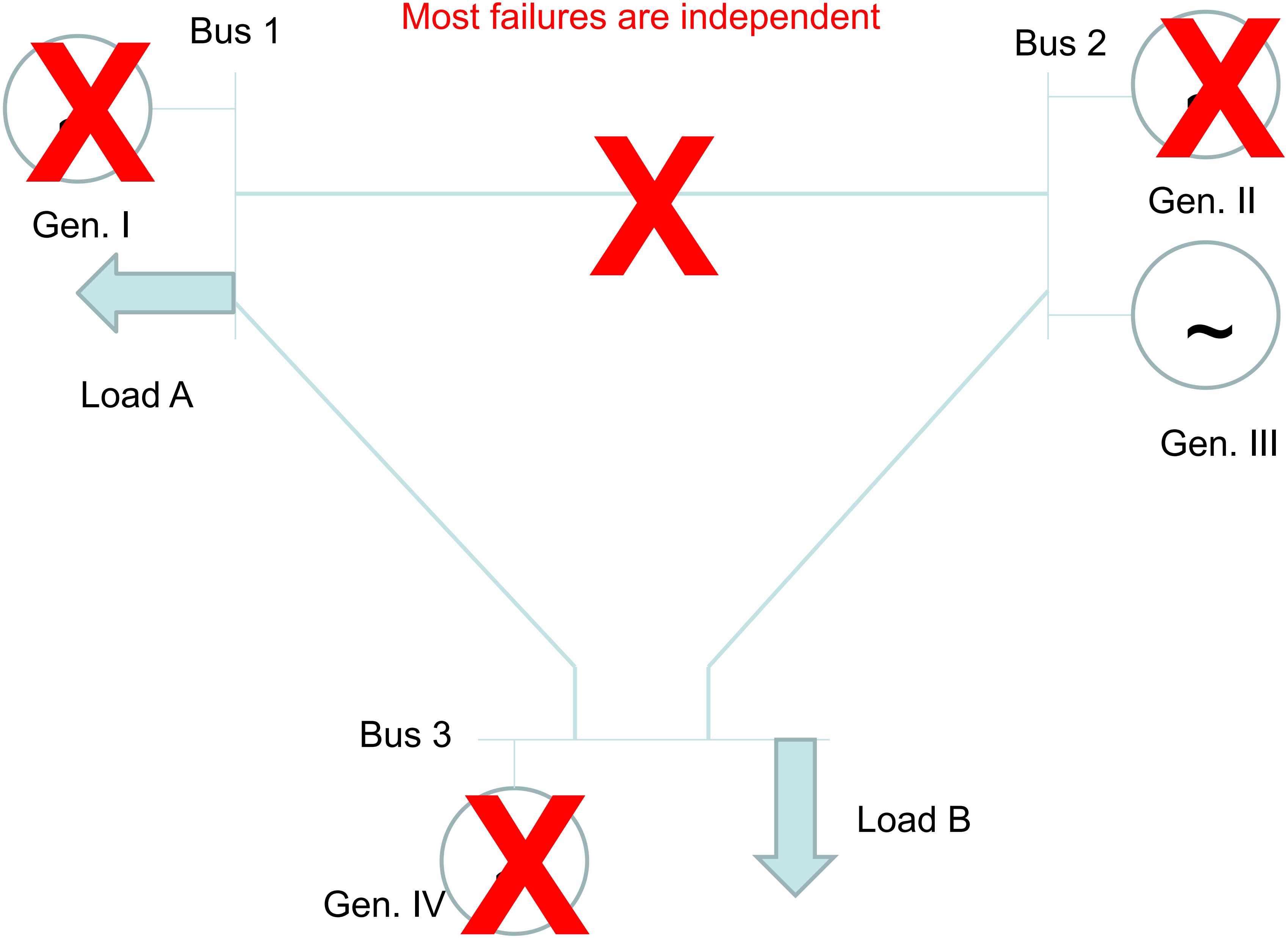
Currents in parallel paths divide themselves in inverse proportion of the impedance of each path

Electricity loop flows means that what happens in Vegas does NOT stay in Vegas

New Jersey is part of PJM, which is part of the Eastern Interconnection



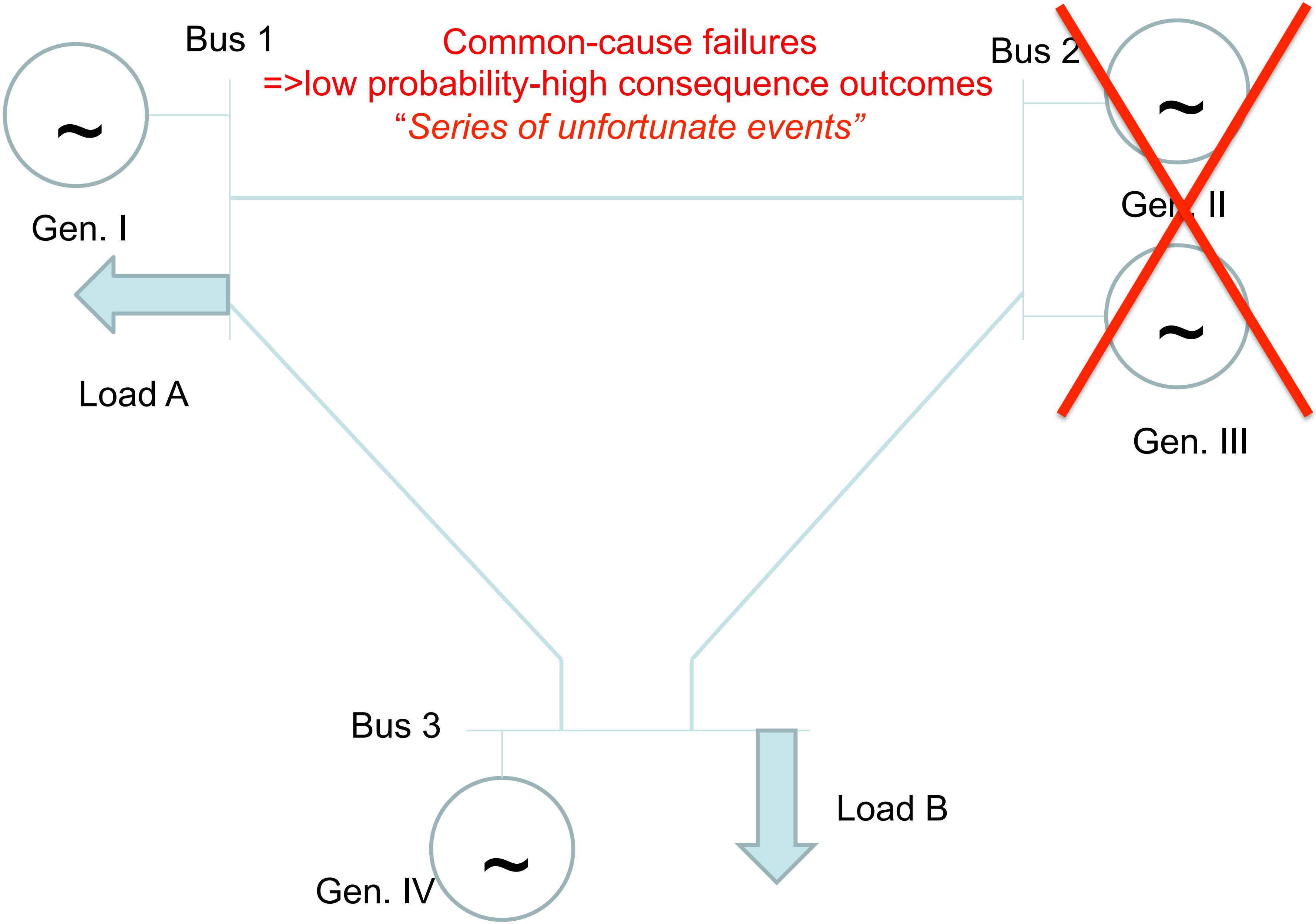
Most failures are independent



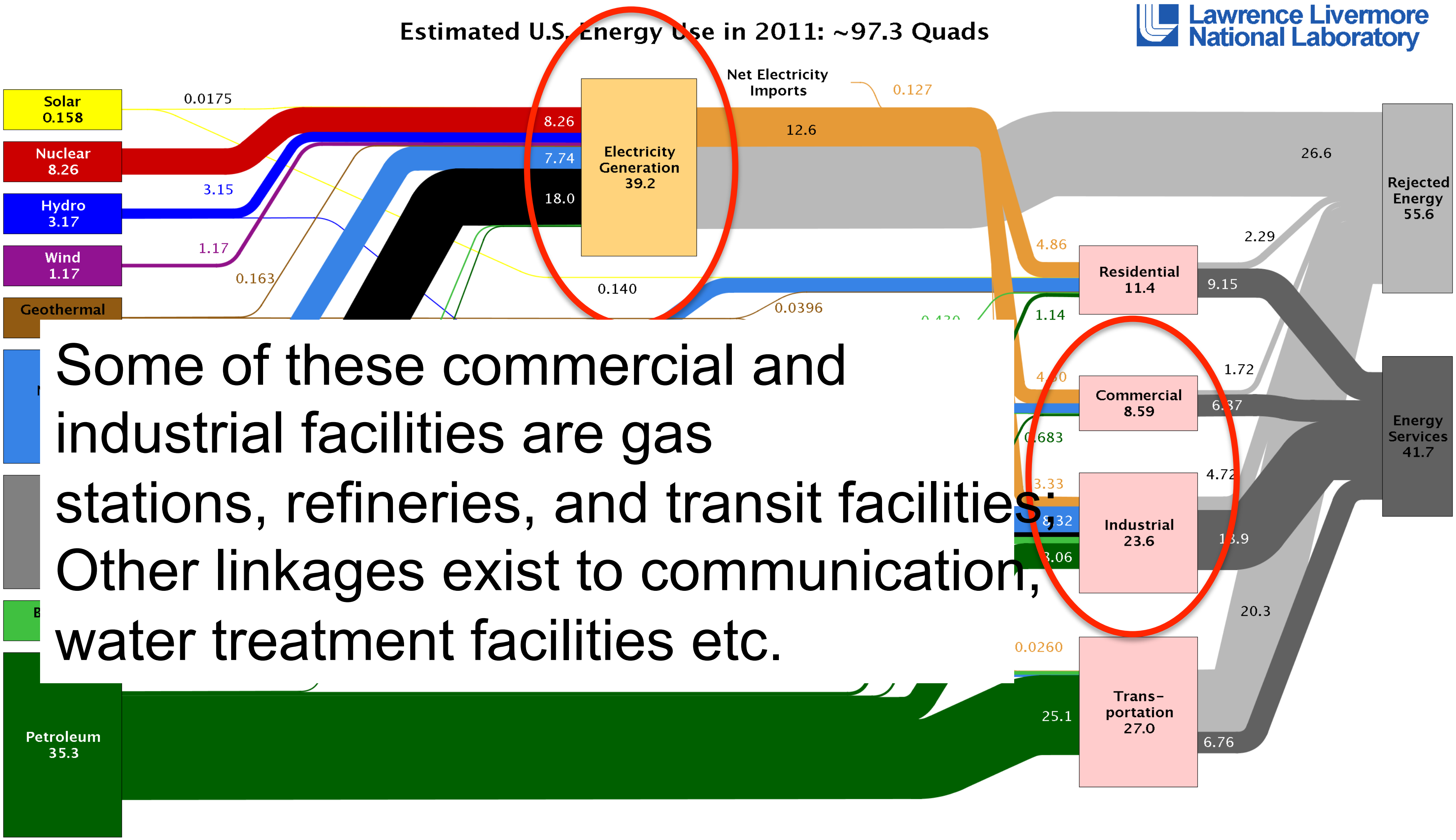
Common-cause failures

=>low probability-high consequence outcomes

"Series of unfortunate events"



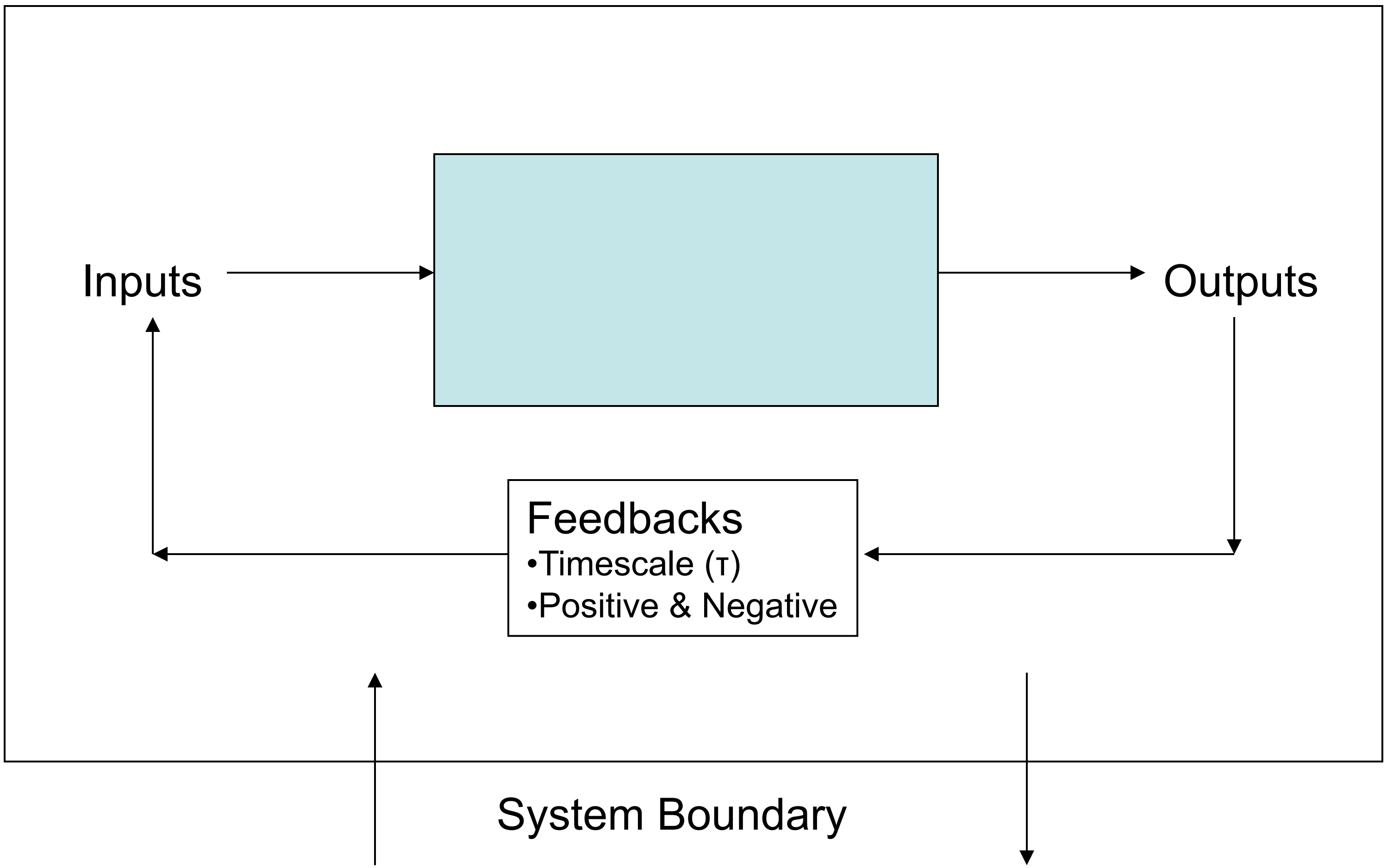
The electric power system is a subsystem to the energy system



Some of these commercial and industrial facilities are gas stations, refineries, and transit facilities; Other linkages exist to communication, water treatment facilities etc.

Source: LLNL 2012. Data is based on DOE/EIA-0384(2011), October, 2012. If this information or a reproduction of it is used, credit must be given to the Lawrence Livermore National Laboratory and the Department of Energy, under whose auspices the work was performed. Distributed electricity represents only retail electricity sales and does not include self-generation. EIA reports flows for non-thermal resources (i.e., hydro, wind and solar) in BTU-equivalent values by assuming a typical fossil fuel plant "heat rate." The efficiency of electricity production is calculated as the total retail electricity delivered divided by the primary energy input into electricity generation. End use efficiency is estimated as 80% for the residential, commercial and industrial sectors, and as 25% for the transportation sector. Totals may not equal sum of components due to independent rounding. LLNL-MI-410527

Even simple deterministic systems with feedbacks are hard to predict
Understanding system behavior is even more challenging for non-experts



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Social Norms, Customs, Values, Traditions
→ Movements, New Institutions and Institutional Reforms

Global, Multinational, National, Regional, State & Local Governance and Institutions

National, Regional, State & Local Laws and Regulations

Supply
(Gov't and Private)

Markets
(Organic and Constructed)
and
Economic Regulation of
Transmission and Distribution

Demand
(Households, Firms, Gov't)

Energy Flows: Primary Energy → Conversion → Energy Services

Energy Stocks and Reserves, Energy Consuming Assets, & Energy Technologies

Reliability

- Bulk Power System
  - Security
  - Adequacy
- Distribution system metrics

Resiliency

- System resiliency
- Resiliency of services

This is a hard problem

- Formally, it involves decision-making under uncertainty involving low probability, high consequence events
- Standard heuristics that we use do not apply and in fact can lead to poor decisions when applied to these types of decisions
- For New Jersey, data and models are for the most part not available off-the-shelf
- Understandably, there are public and political calls for immediate action – and much can be done right away – but analysis of the efficacy of options takes time

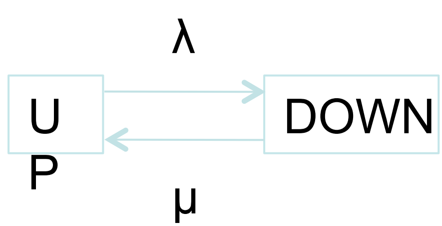
Optimal level of reliability is R*

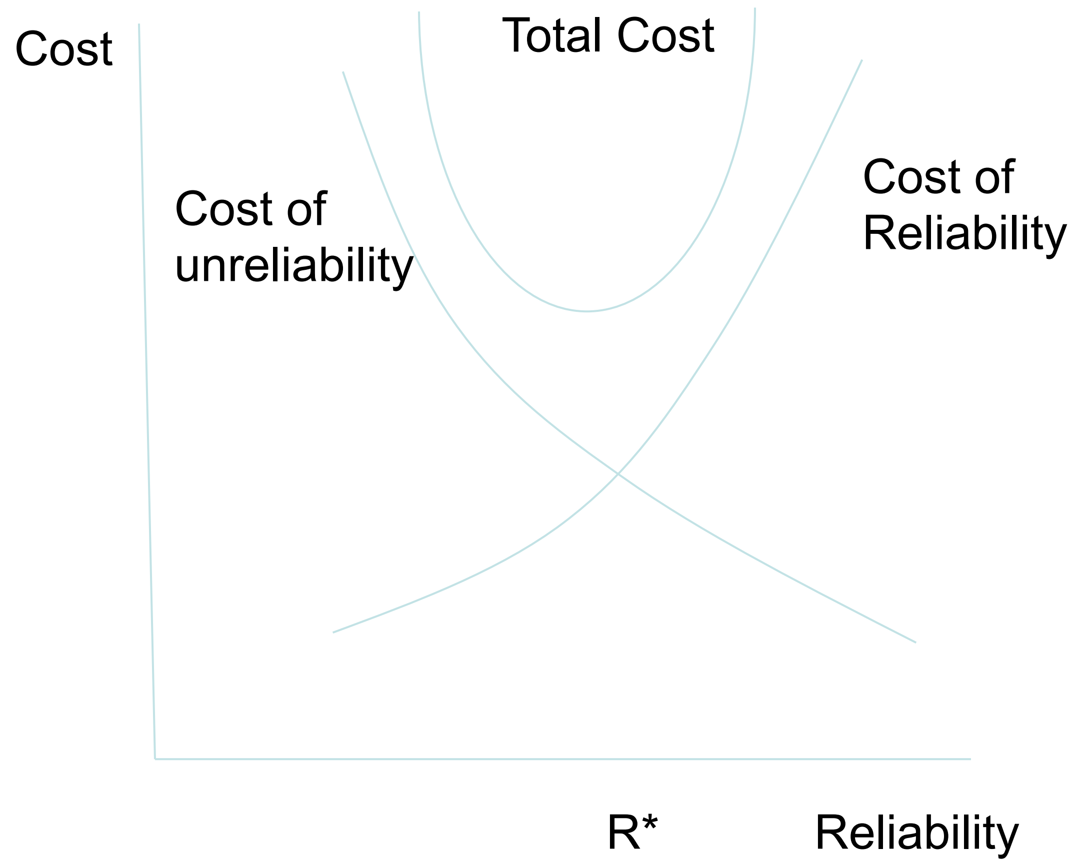
Individual components fail

λ is failure rate

μ is repair rate

Simple, two state model (other, more complicated ones exist):

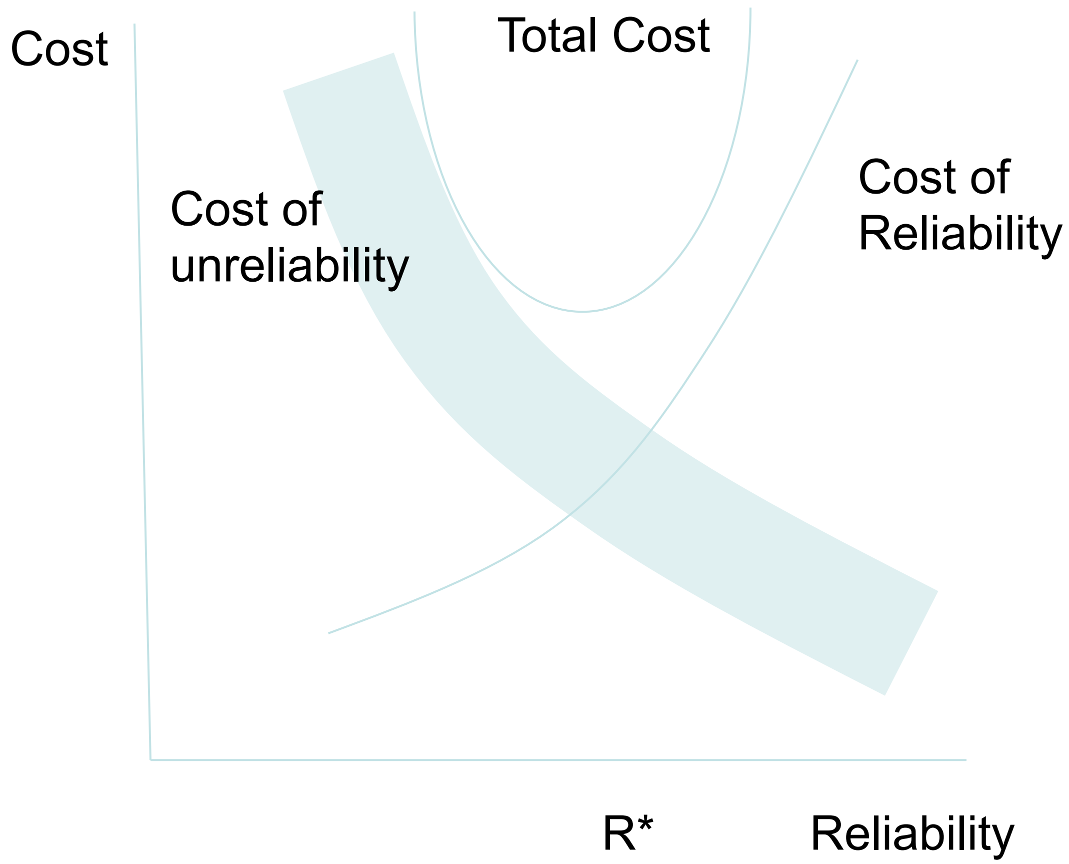




Availability = (MTTF)/(MTTF + MTTR)

- Estimates of the cost of unreliability, known as the value of loss of load (VOLL), vary approximately by a factor of 10

- Estimating VOLL has a long academic and industry history

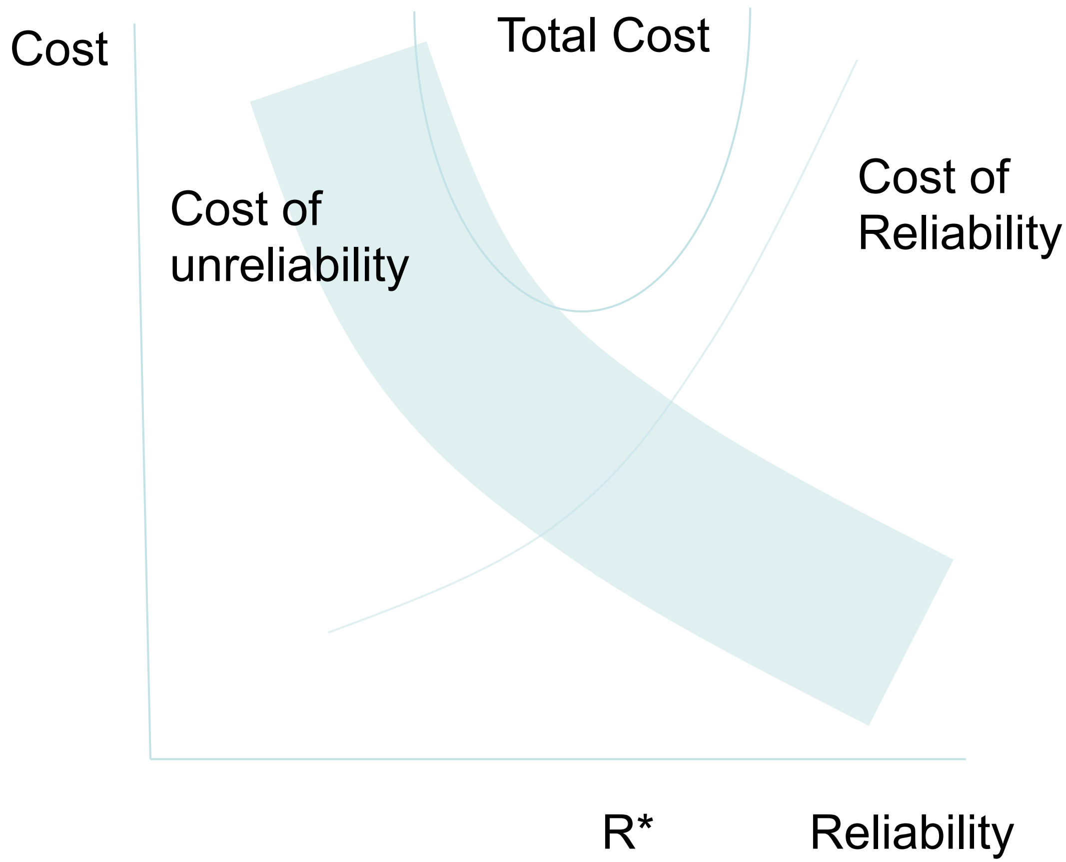


Availability = (MTTF)/(MTTF + MTTR)

The costs of unreliability and cost of reliability depend on the frequency and type of severe weather events

Severe weather events are infrequent, which introduces uncertainty in estimating their frequency

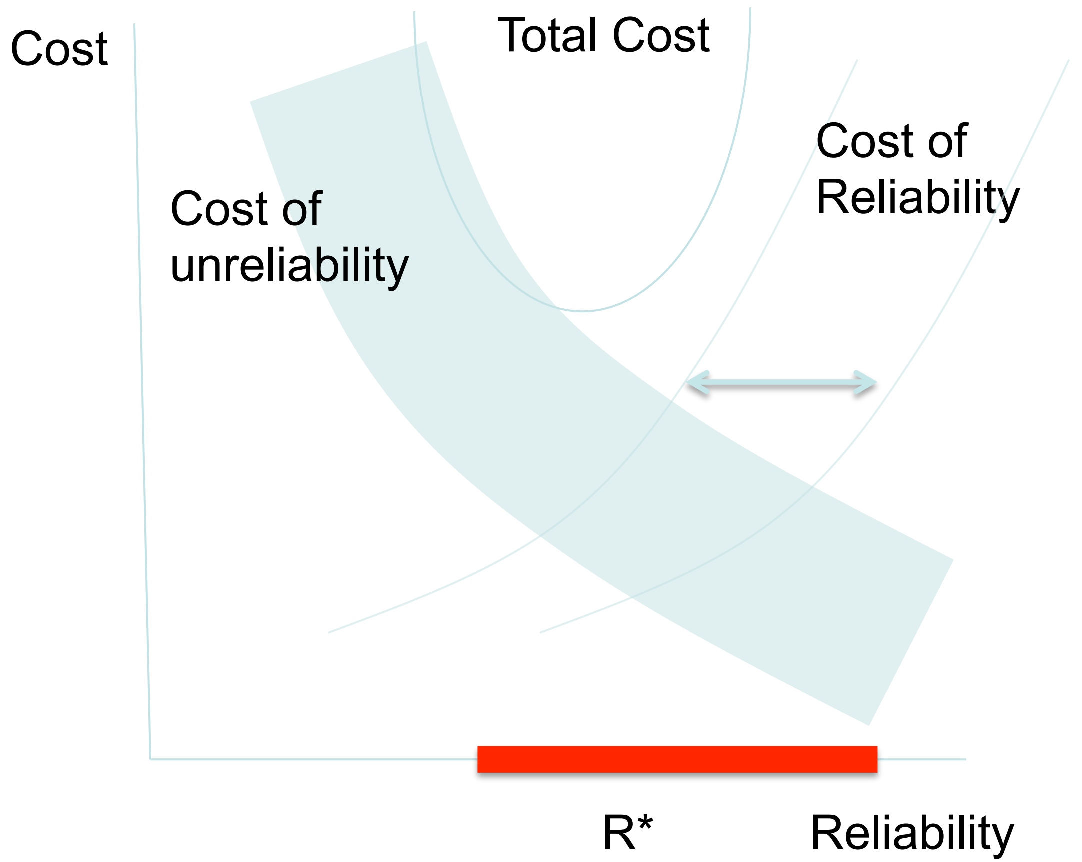
Long-term climate trends may be affecting the frequency and severity of severe weather events, introducing further uncertainty



Cost of unreliability = probability of severe event * VOLL * extent of outage * duration of the outage

Now, where is R* and what is its range of uncertainty?

- The costs of reliability as depends on other non-reliability benefits and costs of reliability measures
- Improving the reliability of the electric power system during severe weather may affect the reliability during other, more frequent, less severe events
- Reliability measures may have other costs and benefits (e.g., changes in emissions) that need to be considered



A Quantitative Risk Assessment Model is Needed

- The quantification of benefits of any proposed response requires determining the probability, magnitude, and duration of the electricity outages that were avoided due to that response
- Different responses will have different impacts on the probability, magnitude and duration of outages
- Responses may interact in complex and unforeseen ways

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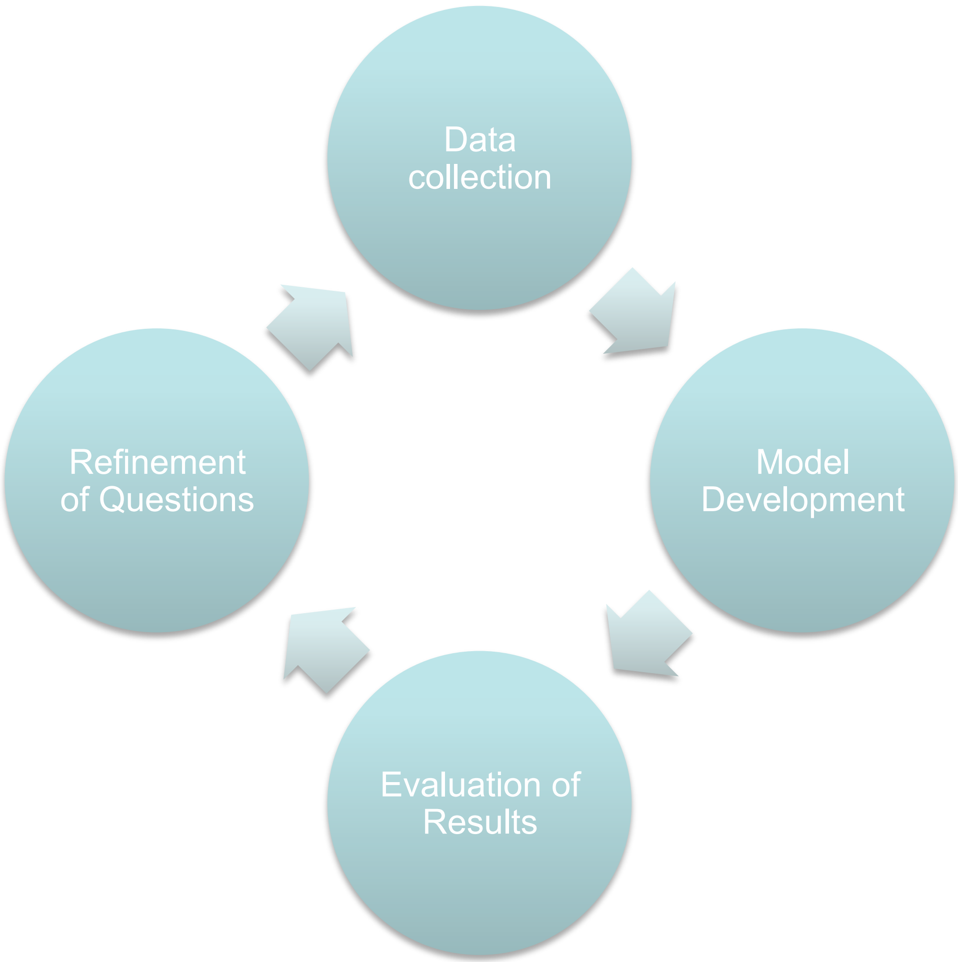
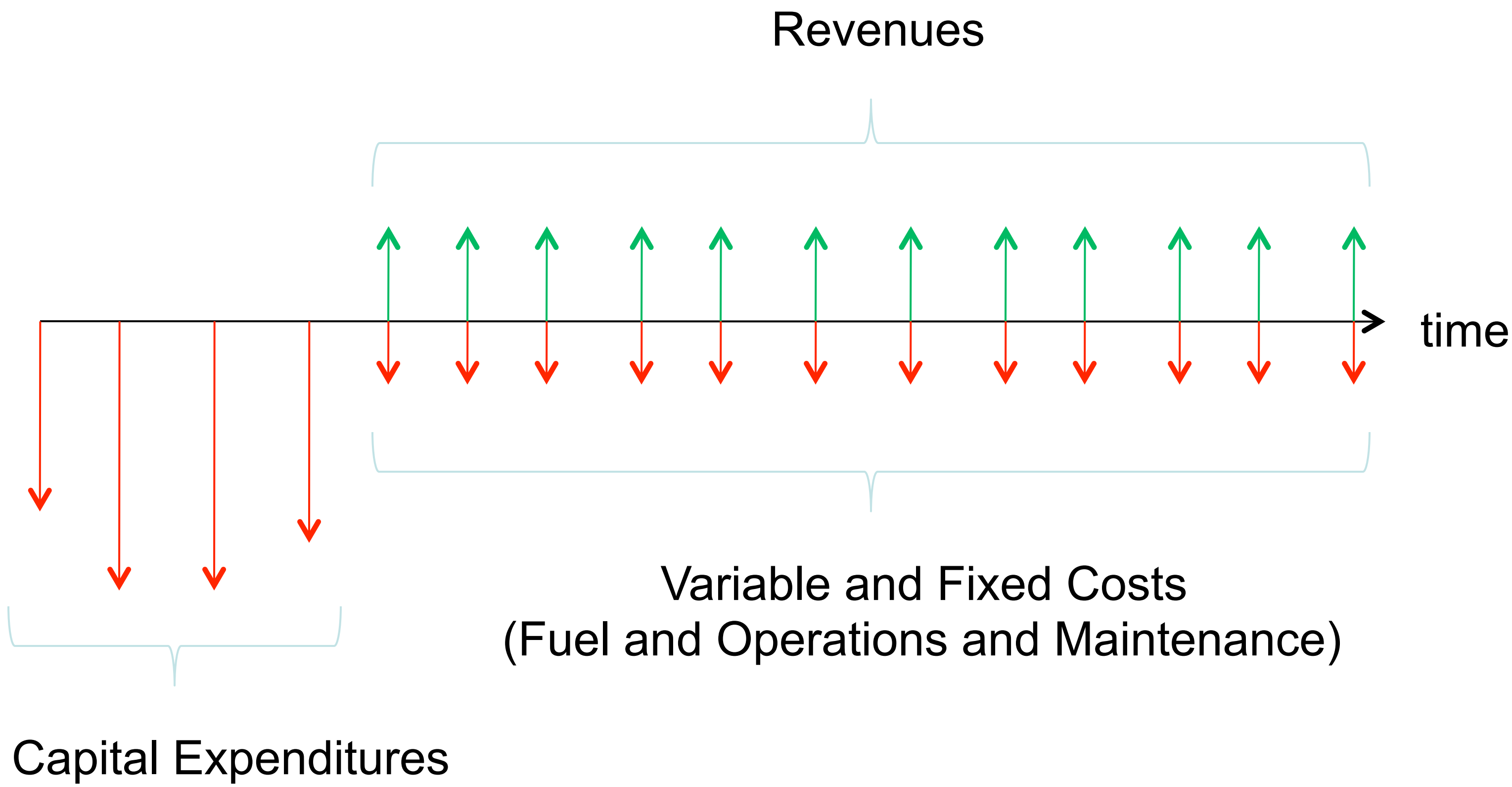
The Uncertainty Itself is Uncertain

- The probabilities, magnitudes and durations of the initiating events (i.e., severe weather) are themselves uncertain
- Overtime (many years), with more data collection, these uncertainties can be updated with new information

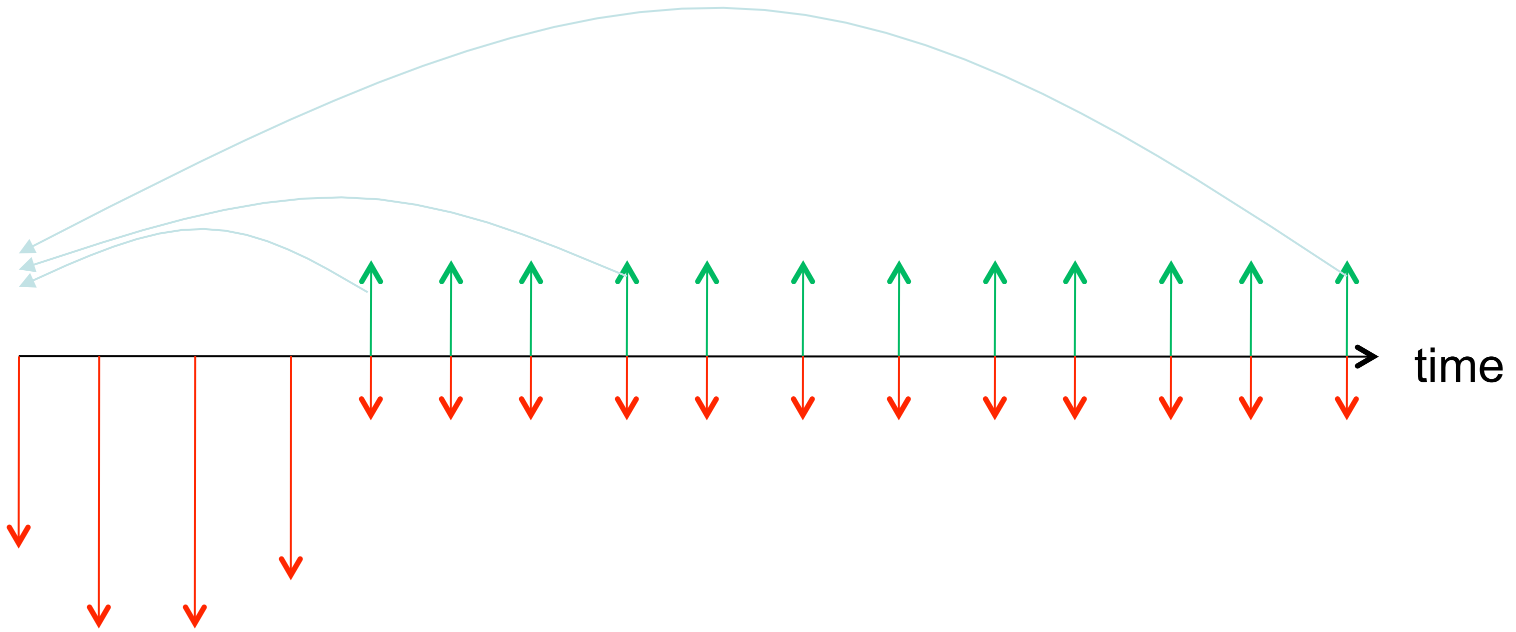
Analysis Requires an Iterative Process

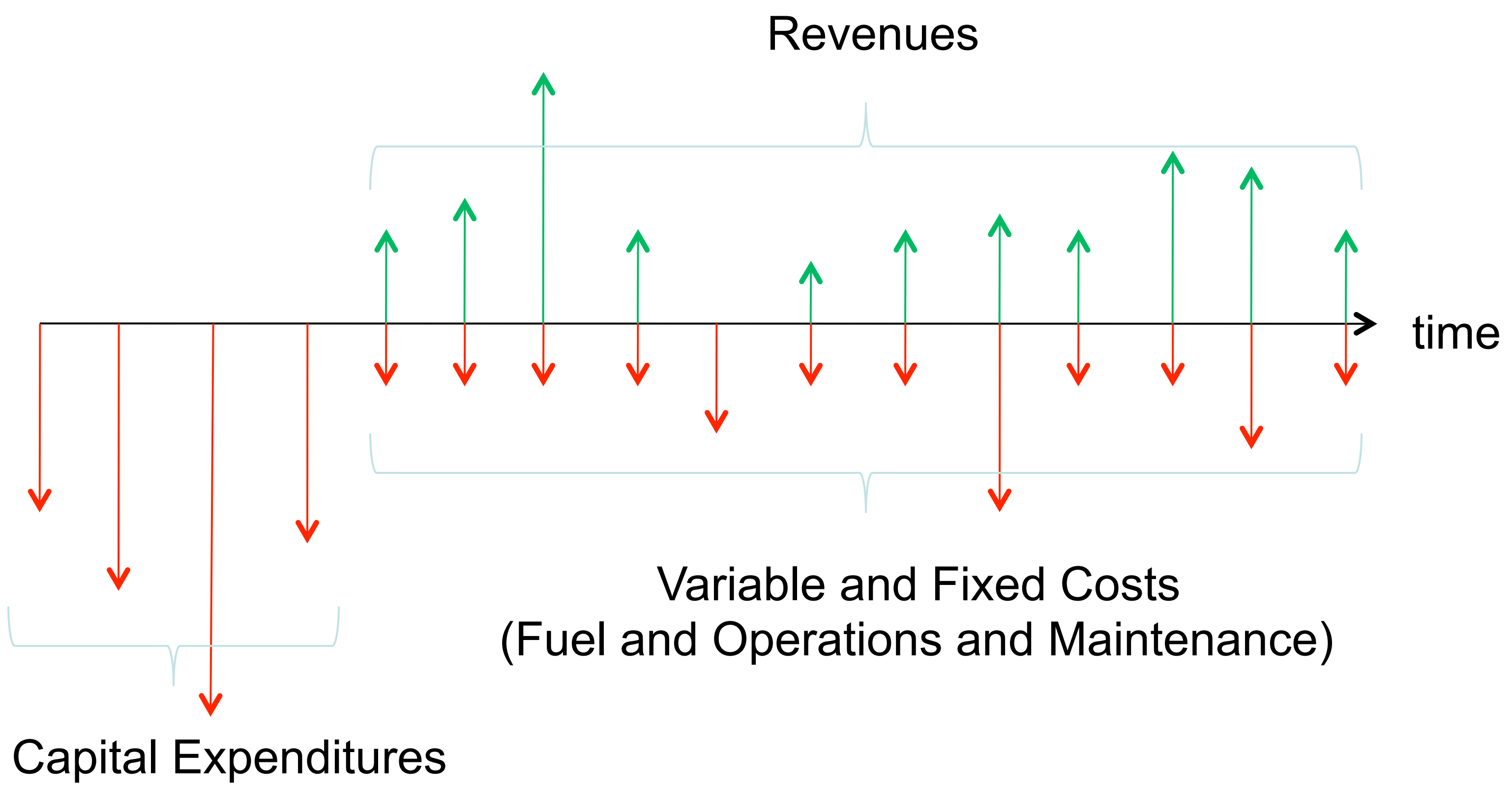


Modeled revenues and Costs over time from an infrastructure investment



Net Present Value (NPV) = ∑ (P_i) summed over all costs and revenues




Revenues
time
Variable and Fixed Costs
(Fuel and Operations and Maintenance)
Capital Expenditures

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Net Present Value Rule: If the NPV is $\geq$ 0, invest, otherwise do not

NPV Critique: Does not account for options that either are eliminated or created and these options may have substantial values that could reverse the outcome of the NPV rule (e.g., approx. +/- 10 to 30% of NPV)

Key intuition: flexibility has value and in many cases it is worth spending money now to preserve or create flexibility

Examples: buy land now, build later; investment in R&D; build a gas turbine for possible conversion to a combined cycle unit; build a coal gasification plant with possible addition of carbon capture and sequestration; building a power plant terminates the option of waiting, which has some value

Robert Pindyck; Richard de Neufville

Applications of engineering economics typically do not capture the key insight of economics, which is that incentives matter

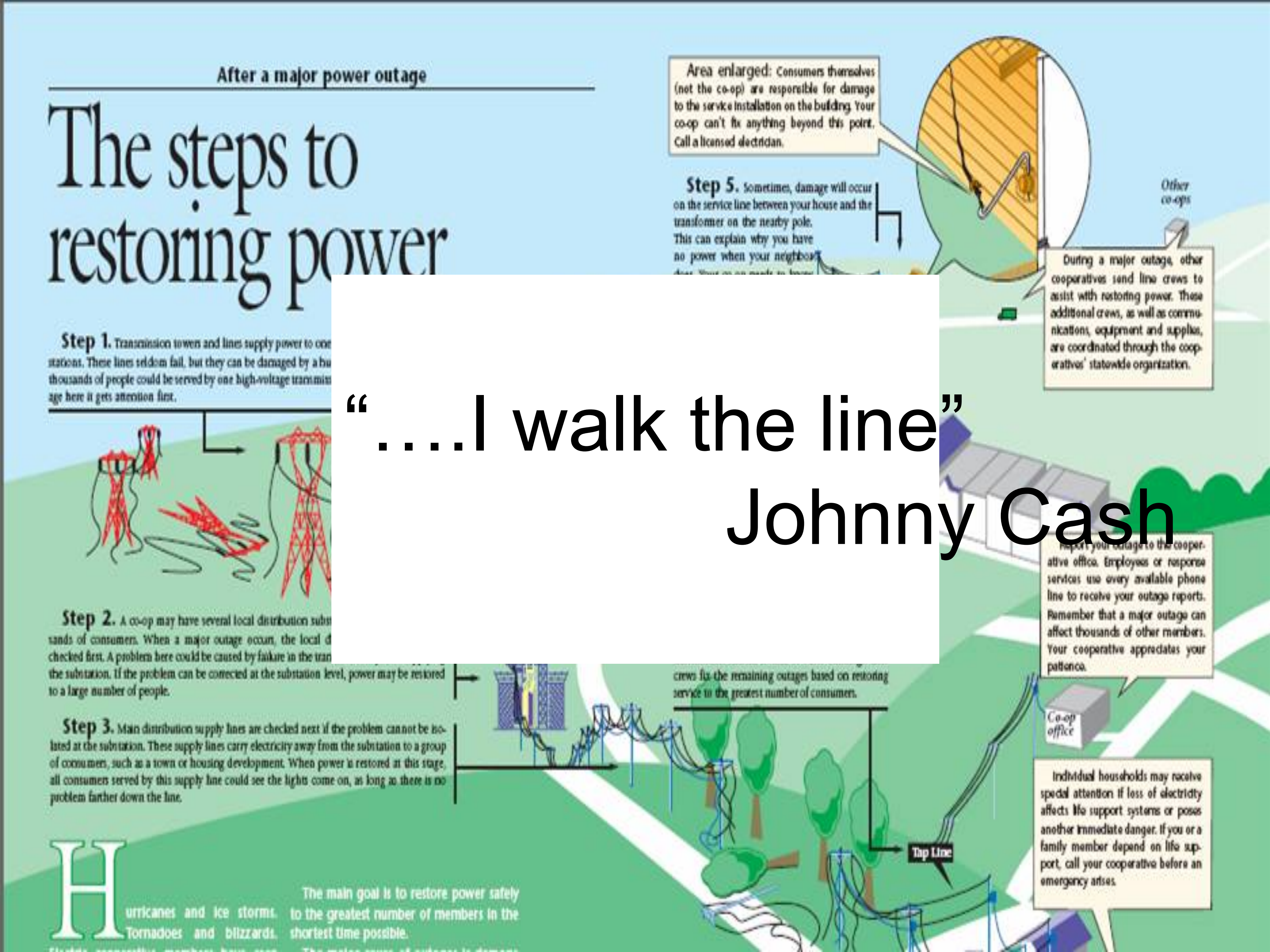
An important example of the importance of incentives, although not the only one, is given the large amounts of uncertainty over the life of investments, flexibility has value that needs to be incorporated into the analysis

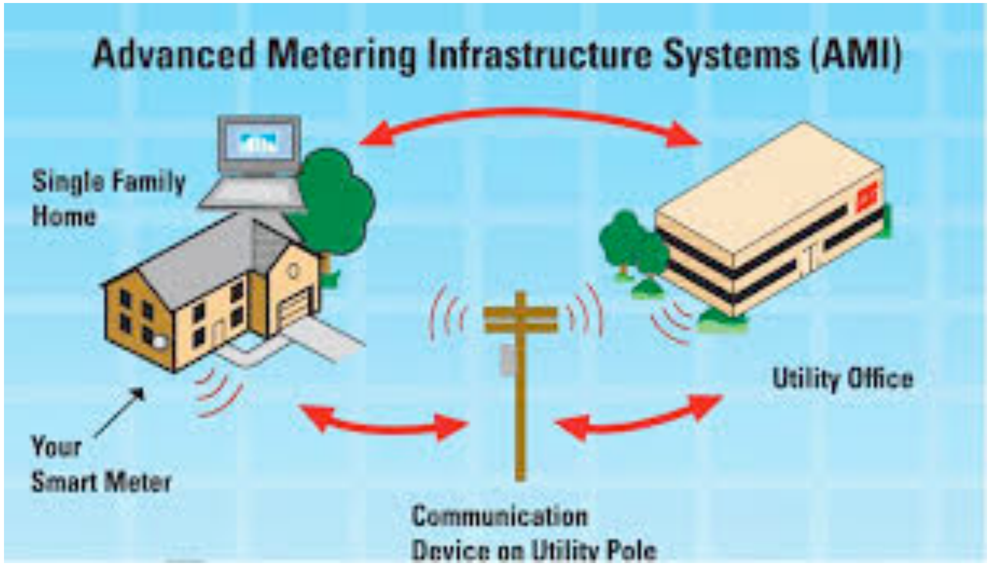
Another is that government or utility financing of infrastructure typically involves the transfer of risk to residents of that jurisdiction

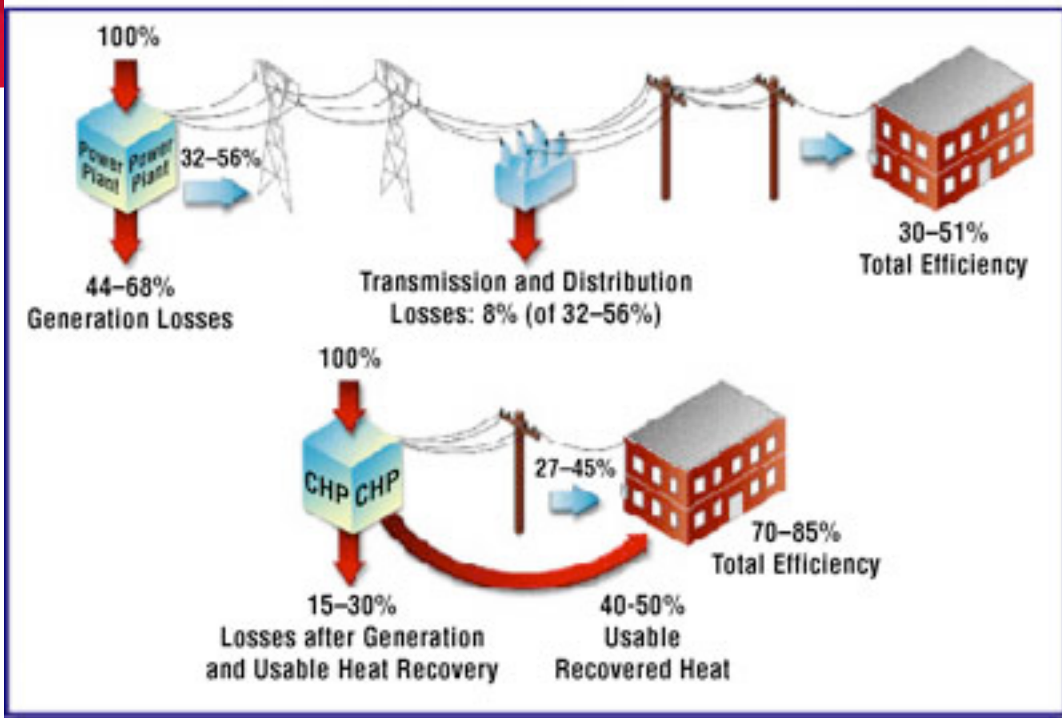
Different Solutions have Different Implications

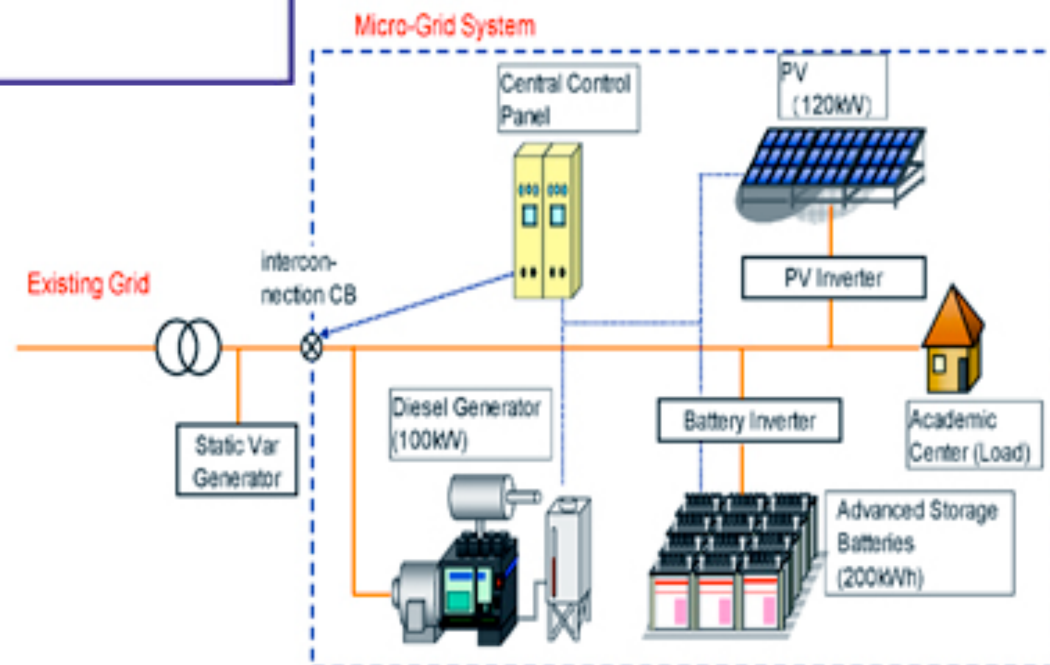
1. Vegetation management
2. Improved communications
3. Improved predictions of restoration times
4. Automatic switching
5. Hardening distribution facilities
6. Backup power/distributed generation
7. Moving substations/switching stations
8. Redundancy of key faculties
9. Undergrounding of distribution lines

“….I walk the line”
Johnny Cash




Advanced Metering Infrastructure Systems (AMI)
Single Family Home
Your Smart Meter
Communication Device on Utility Pole
Utility Office


100%
Power Plant
32–56%
44–68%
Generation Losses
Transmission and Distribution
Losses: 8% (of 32–56%)
30–51%
Total Efficiency
100%
CHP
27–45%
70–85%
Total Efficiency
15–30%
Losses after Generation
and Usable Heat Recovery
40-50%
Usable
Recovered Heat


Micro-Grid System
Central Control
Panel
PV
(120kW)
PV Inverter
Existing Grid
intercon-
nection CB
Static Var
Generator
Diesel Generator
(100kW)
Battery Inverter
Academic
Center (Load)
Advanced Storage
Batteries
(200kWh)

Analytical infrastructure

Communication infrastructure

Physical infrastructure

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Possible Ways of Moving Forward

- Start with simple spreadsheet models examining individual measures in isolation
- Back calculate the conditions under which each measure is cost-effective
- Connect various measures to try to understand system interactions
- Develop formal optimization models
- Revise as new data becomes available, perhaps as a result of analysis identifying key assumptions

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AGENDA

1. Explaining how the CHP Stylized Model works
2. Points for discussion
    1. Capacity Factor assumptions
    2. Quantification of T&D avoided cost benefits
    3. Reliability benefit calculation assumptions
3. Response to stakeholder comments received
4. Next Steps

We would like to thank the Rate Counsel, Gearoid Foley, Anne-Marie Peracchio (NJNG), TRC for their time and valuable inputs.

Note: References used and other reports by CEEEP can be found at http://policy.rutgers.edu/ceeep/chp

Principles of Cost-Benefit Analysis (recap from last WG meeting – June 19, 2013)

SOCIAL

COSTS

- ✓ CHP Incentives
- ✓ Gas T&D costs (for additional supply of gas to CHP)

BENEFITS

- ✓ Increased Reliability resulting in community benefits such as storm shelter etc.
- ✓ Avoided electric T&D costs
- ✓ Reduction in air emissions

PRIVATE

COSTS

- ✓ Capital Costs
- ✓ Fuel Costs
- ✓ O&M Costs

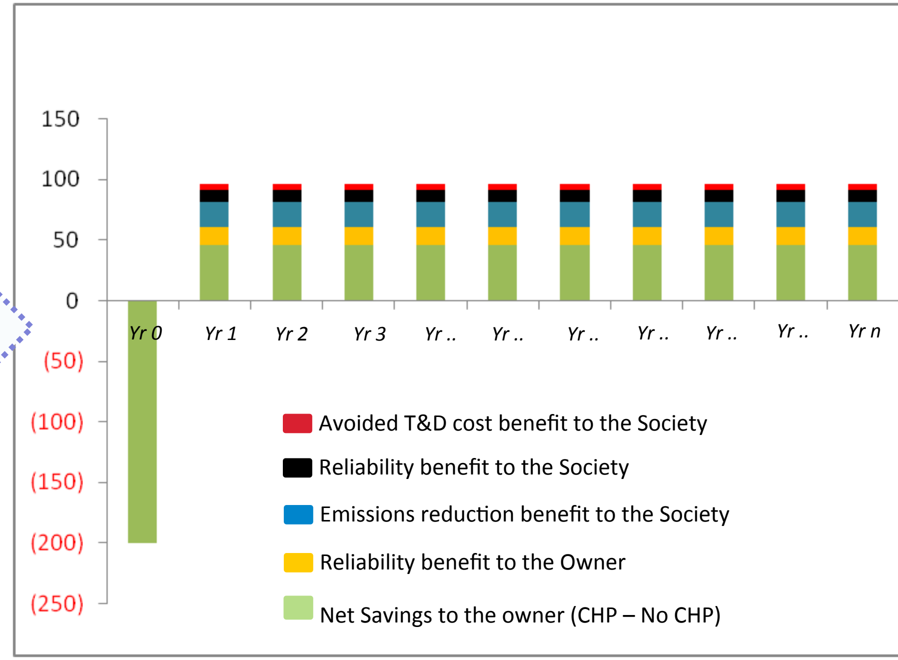
BENEFITS

- ✓ Increased Reliability
- ✓ Savings on electricity supply bills (after paying for standby charges)

There could be some macroeconomic effects (such as job growth) which could be positive or negative

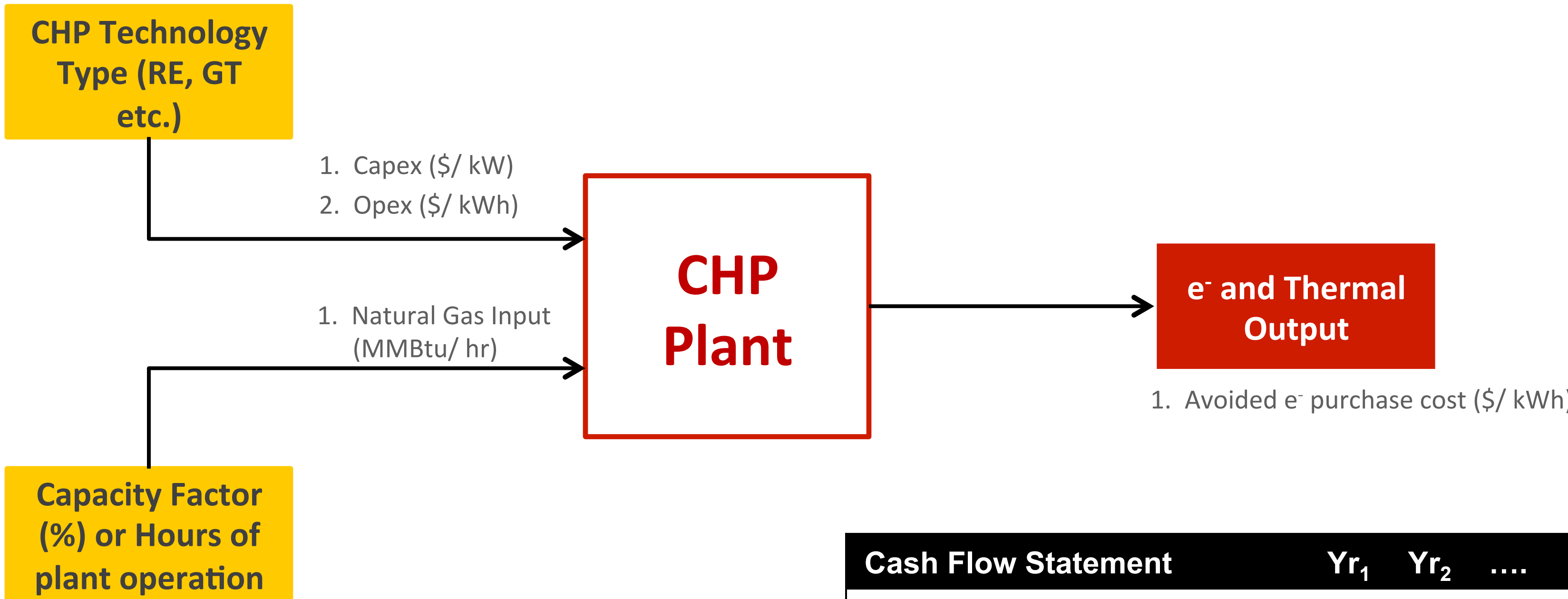
The above does not consider impact of SBC & SUT

Net Benefits to Society (Project developer + rest of the society)



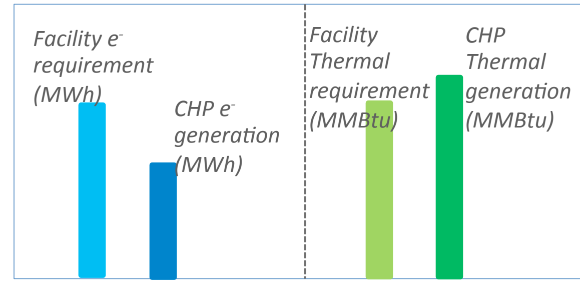
1. Installed Capital Cost would account for incentives, if any, received by the CHP Owner
2. Capital Cost assumption includes costs for Black Start & islanding capability
3. Reliability benefits in part would depend upon the Owner's (& Society's) ability to realize benefits in case of a grid outage

Structure of the Stylized Model (1/5)



Cash Flow Statement	Yr_1	Yr_2	....	Yr_n
Costs: 1. Capex 2. Opex 3. Fuel Cost				
Savings: 1. Avoided e- purchase costs				
Net Benefit = Savings - Costs				

Structure of the Stylized Model (2/5)



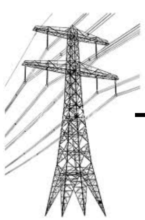
CHP Technology Type (RE, GT etc.)

- Capex ($/ kW)
- Opex ($/ kWh)

CHP Plant

- Natural Gas Input (MMBtu/ hr)

Capacity Factor (%) or Hours of plant operation



- Additional e⁻ purchase from grid ($/ kWh)

e- and Thermal Output

- Avoided e⁻ purchase cost ($/ kWh)

Cash Flow Statement	Yr_1	Yr_2	….	Yr_n
Costs: 1. Capex 2. Opex 3. Fuel Cost 4. Additional e- purchase costs				
Savings: 1. Avoided e- purchase costs				
Net Benefit = Savings - Costs				

Structure of the Stylized Model (3/5)

Reliability benefit depends upon two factors:

1. VOLL – which depends upon the user, and
2. Outage period – total number of days for which grid supply remains unavailable

CHP Technology Type (RE, GT etc.)

- Capex ($/ kW)
- Opex ($/ kWh)

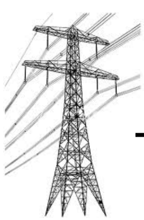
CHP Plant

e- and Thermal Output

- Avoided e⁻ purchase cost ($/ kWh)

- Natural Gas Input (MMBtu/ hr)

Capacity Factor (%) or Hours of plant operation



- Additional e⁻ purchase from grid ($/ kWh)

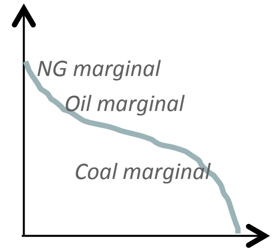
Black start & islanding capability

- Additional Capex ($/ kW)

Cash Flow Statement	Yr_1	Yr_2	….	Yr_n
Costs: 1. Capex (+ for B/S & islanding) 2. Opex 3. Fuel Cost 4. Additional e- purchase costs				
Savings: 1. Avoided e- purchase costs 2. VOLL benefit				
Net Benefit = Savings - Costs				

Structure of the Stylized Model (4/5)

Depending upon the number of hours of operation of a CHP plant, the model calculates which type of marginal plant (coal, gas or oil) would be displaced by the CHP.



CHP Technology Type (RE, GT etc.)

- Capex ($/ kW)
- Opex ($/ kWh)

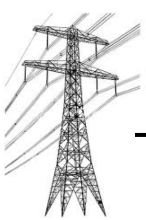
CHP Plant

- Natural Gas Input (MMBtu/ hr)

e- and Thermal Output

- Avoided e^- purchase cost ($/ kWh)

Capacity Factor (%) or Hours of plant operation



- Additional e^- purchase from grid ($/ kWh)

Black start & islanding capability

- Additional Capex ($/ kW)

Cash Flow Statement	Yr_1	Yr_2	….	Yr_n
Costs: 1. Capex (+ for B/S & islanding) 2. Opex 3. Fuel Cost 4. Additional e- purchase costs				
Savings: 1. Avoided e- purchase costs 2. VOLL benefit 3. Emissions reduction benefit				
Net Benefit = Savings - Costs				

Structure of the Stylized Model (5/5)

Standby charges are ratchet up – such that if the CHP is out for few days in a summer month, then it has to pay

1. Summer standby charges for that month, and
2. Normal standby charges, for rest of the months in that year

CHP Technology Type (RE, GT etc.)

- Capex ($/ kW)
- Opex ($/ kWh)

- Natural Gas Input (MMBtu/ hr)

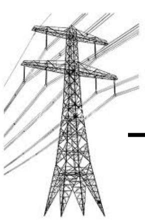
CHP Plant

e- and Thermal Output

- Avoided e^- purchase cost ($/ kWh)

Capacity Factor (%) or Hours of plant operation

CHP Plant Trips



- Additional e^- purchase from grid ($/ kWh) + **Extra purchases from grid**

Black start & islanding capability

- Additional Capex ($/ kW)

Cash Flow Statement	Yr_1	Yr_2	….	Yr_n
Costs: 1. Capex (+ for B/S & islanding) 2. Opex 3. Fuel Cost (+ to meet Thermal need) 4. Additional e- purchase costs 5. Standby Charges				
Savings: 1. Avoided e- purchase costs 2. VOLL benefit 3. Emissions reduction benefit				
Net Benefit = Savings - Costs				

Hypothetical examples - assumptions

Example 1: 1,150 MW Gas Turbine

Project Level Assumptions

1. System rated capacity = ISO Power Rating x 0.93
2. CHP Capacity Factor = 95%
3. CHP Capital Cost = 3,324 $/kW
4. Cost escalation = 2.20%
5. Debt: Equity ratio = 80:20
6. Weighted Avg. Cost of Capital = 8.00%
7. Federal Investment Tax Credit = 10.00%

Facility Level Assumptions

1. Annual Peak Demand = 2,300 kW
2. Load Factor = 60%
3. Boiler Efficiency = 80%

Tariff Assumptions

1. Electricity tariff (commodity + T&D + taxes) = 0.13 $/kWh
2. NG tariff (commodity + T&D + taxes) = 7.91 $/MMBtu
3. Tariff escalation → electricity @ 1.98% and NG @ 3.20%

Example 2: 1,000 MW Reciprocating Engine

Project Level Assumptions

1. System rated capacity = Continuous Power Rating x 0.96
2. CHP Capacity Factor = 94%
3. CHP Capital Cost = 1,600 $/kW
4. Cost escalation = 2.20%
5. Debt: Equity ratio = 80:20
6. Weighted Avg. Cost of Capital = 8.00%
7. Federal Investment Tax Credit = 10.00%

Facility Level Assumptions

1. Annual Peak Demand = 2,000 kW
2. Load Factor = 60%
3. Boiler Efficiency = 80%

Tariff Assumptions

1. Electricity tariff (commodity + T&D + taxes) = 0.13 $/kWh
2. NG tariff (commodity + T&D + taxes) = 7.91 $/MMBtu
3. Tariff escalation → electricity @ 1.98% and NG @ 3.20%

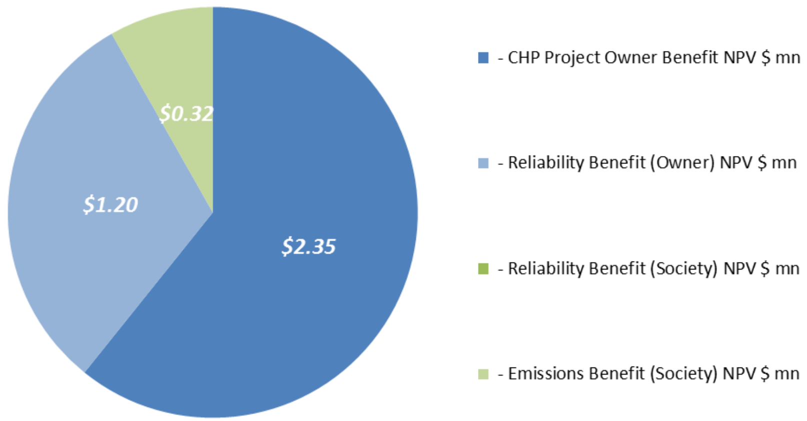
Hypothetical examples - results

Example 1: 1,150 MW Gas Turbine

To the Project Developer (excluding reliability benefits)

1. CHP Project Efficiency = 70%
2. Project NPV = $ 2.35
3. Project IRR = 17%
4. B/C Ratio = 1.78

To the Society (including Project Developer)



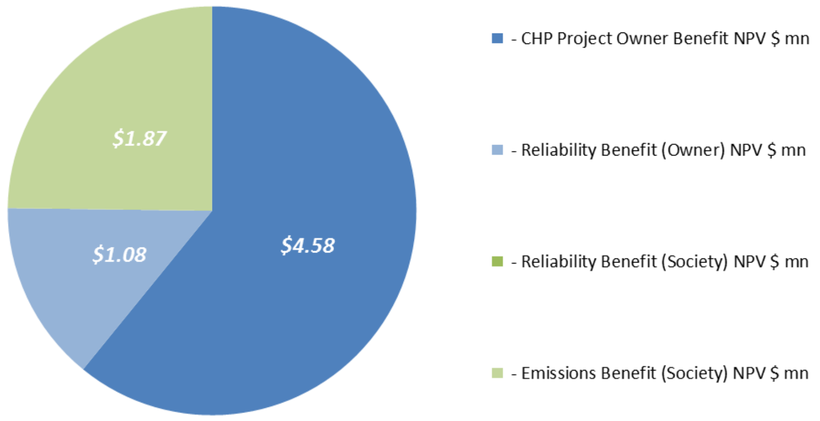
1. CO2 savings in Yr 1 = 4,723,419 lbs
2. NPV of emissions benefit (after accounting for CHP Incentive cost and Federal investment tax credit) = $ 0.32

Example 2: 1,000 MW Reciprocating Engine

To the Project Developer (excluding reliability benefits)

1. CHP Project Efficiency = 82%
2. Project NPV = $ 4.58
3. Project IRR = 51%
4. B/C Ratio = 3.79

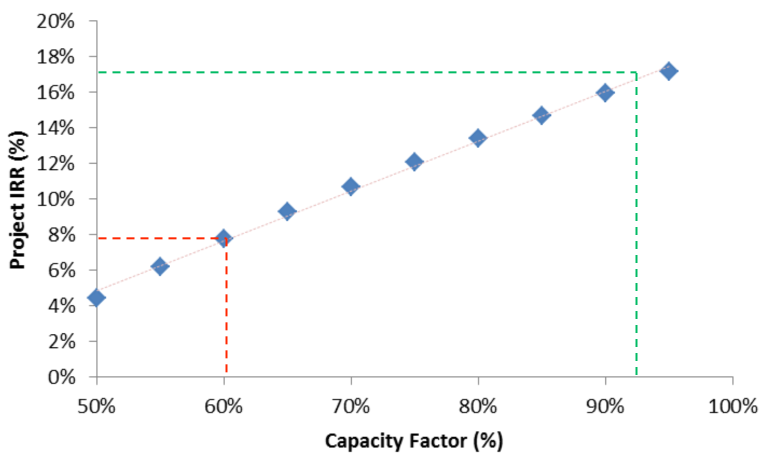
To the Society (including Project Developer)



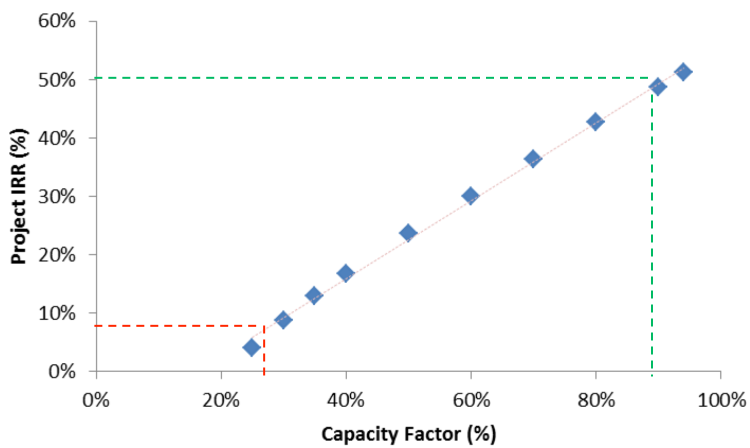
1. CO2 savings in Yr 1 = 9,969,617 lbs
2. NPV of emissions benefit (after accounting for CHP Incentive cost and Federal investment tax credit) = $ 1.87

Hypothetical examples – observations related to plant CF

Example 1: 1,150 MW Gas Turbine



Example 2: 1,000 MW Reciprocating Engine



1. Capacity Factor plays an important role in determining a project's IRR
2. CHP projects breakeven (Zero NPV) at low capacity factors,
    1. Breakeven CF for GT example = ~ 60%
    2. Breakeven CF for RE example = ~ 30%
3. It is important to note that if a plant is running at low capacity factor → which means the 'number of hours of operation' are less → it shall also have an effect on the emissions reduction benefit.
    1. GT example: reduction of CF from 95% to 60% results in reduction of net CO2 emissions benefit by 66%
        1. Net CO2 emissions under 95% CF = 4,723,419 lbs
        2. Net CO2 emissions under 60% CF = 1,588,812 lbs
    2. RE example: reduction of CF from 94% to 30% results in reduction of net CO2 emissions benefit by 88%
        1. Net CO2 emissions under 94% CF = 9,969,617 lbs
        2. Net CO2 emissions under 30% CF = 1,225, 382 lbs

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4. Next Steps

We would like to thank the Rate Counsel, Gearoid Foley, Anne-Marie Peracchio (NJNG), TRC for their time and valuable inputs.

Note: References used and other reports by CEEEP can be found at http://policy.rutgers.edu/ceeep/chp

Based on publicly available sources, CEEEP has put together a database of CHP plants in NJ with capacity > 1 MW

Source of information:

- **eGRID Data files** for years 2009, 2007, 2005 & 2004
- **EIA (Survey Form 923)** for years 2011, 2010, 2008, 2006, 2003 & 2002

Database captures info for 48 CHP plants in NJ with installed capacity > 1 MW*

Type of Prime Mover	No. of plants
CT (Combined Cycle Combustion Turbine)	20
GT (Combustion Gas Turbine)	11
IC (Internal Combustion Engine)	8
ST (Steam Turbine)	9

Type of Facility	No. of plants (2011)
Chemicals	8
Refining	3
University	2
Printing/ Publishing	2
Food Processing	1
Office Building	-
Solid Waste Facilities	-
Instruments	1
Justice/ Public Order	1
Pulp & Paper	-
Wastewater Treatment	1
Others	3

Complete database can be found at http://policy.rutgers.edu/ceeep/chp

* Data not available for all plants for all 10 years

It is observed that on an average the CHP plants have been operating at an average CF of ~ 48% for last 10 years

	2011	2010	2009	2008	2007*	2006	2005	2004	2003	2002
Total Number of Plants #	**22**	**24**	**35**	**23**	**31**	**28**	**37**	**39**	**28**	**36**
Total Capacity of Plants (MW) #	**2,604**	**2,621**	**5,070**	**2,982**	**3,568**	**3,159**	**3,772**	**3,840**	**3,501**	**3,651**
Min CF	6%	1%	1%	4%	1%	3%	1%	1%	3%	5%
Avg. CF	45%	42%	42%	48%	51%	47%	47%	46%	51%	56%
Std. Dev.	26%	26%	28%	28%	30%	29%	27%	29%	26%	27%
Max CF	91%	87%	90%	88%	120%	98%	88%	94%	88%	95%

Data not available for all plants for all 10 years; some plants might have closed and some started operation later

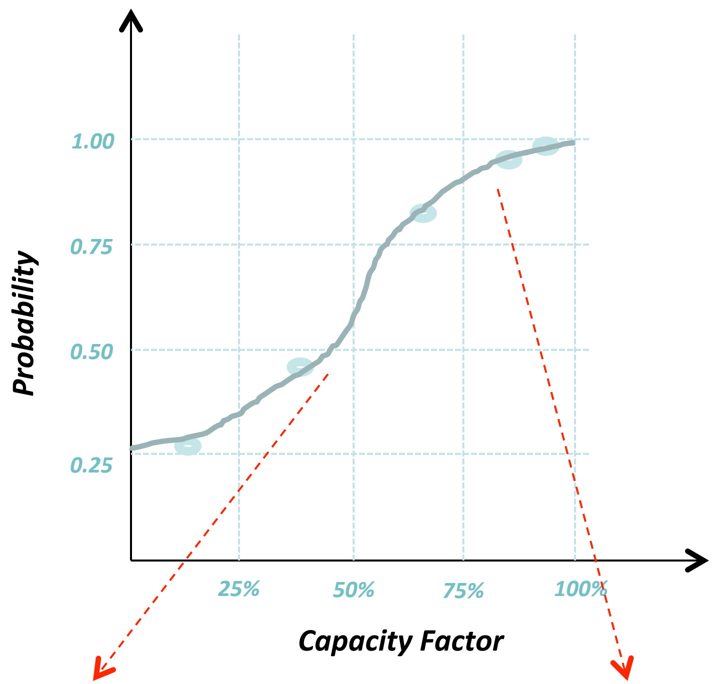
* Calculation of Avg. CF (2007) takes into account the max data point of value 120%

Ocean County Landfill 4.8 MW IC engine CHP; CF % as reported in the eGRID data files 2007

Probability of a CHP plant consistently running at very high CF is found to be "low"

Segregating data points	No. of data points	Probability of operation
Data points with CF > 90%	8	3%
Data points with 75% < CF < 90%	49	16%
Data points with 50% < CF < 75%	105	35%
Data points with 25% < CF < 50%	59	19%
Data points with 0% < CF < 25%	82	27%
TOTAL Data Points	303*	

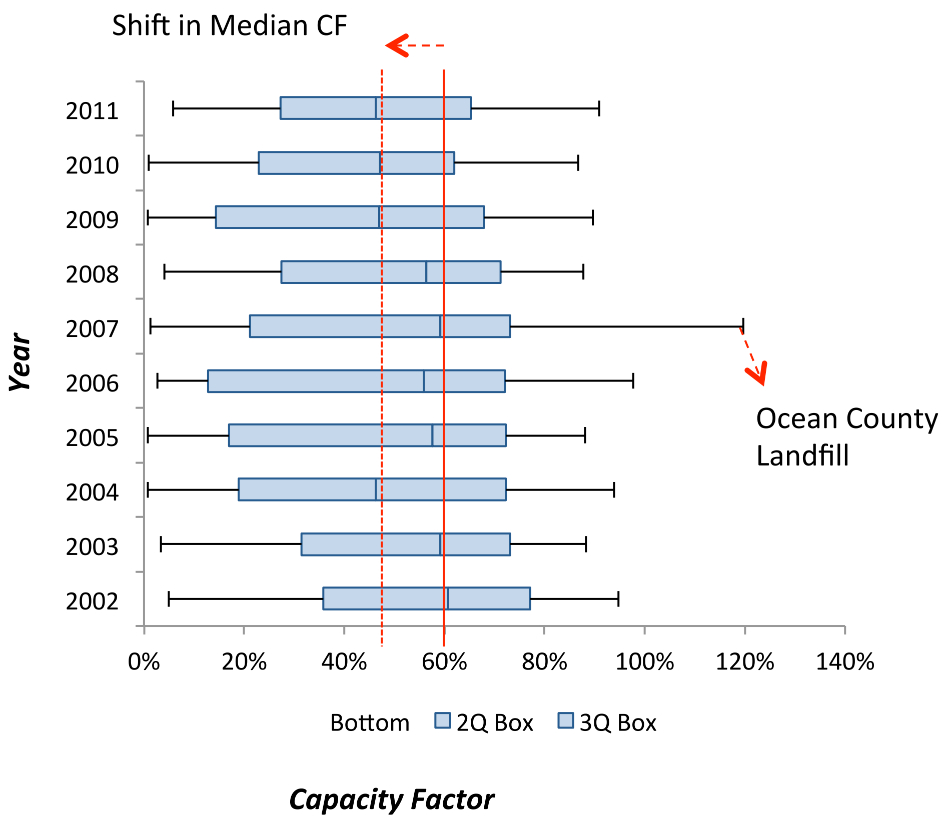
* Total number of CF data points (together for all plants in all years) in the database



Probability of plant operating **below 50% CF is ~ 50%**

Probability of plant operating **above 75% CF is ~ 20%**

Yearly Capacity Factor distribution for NJ CHP plants



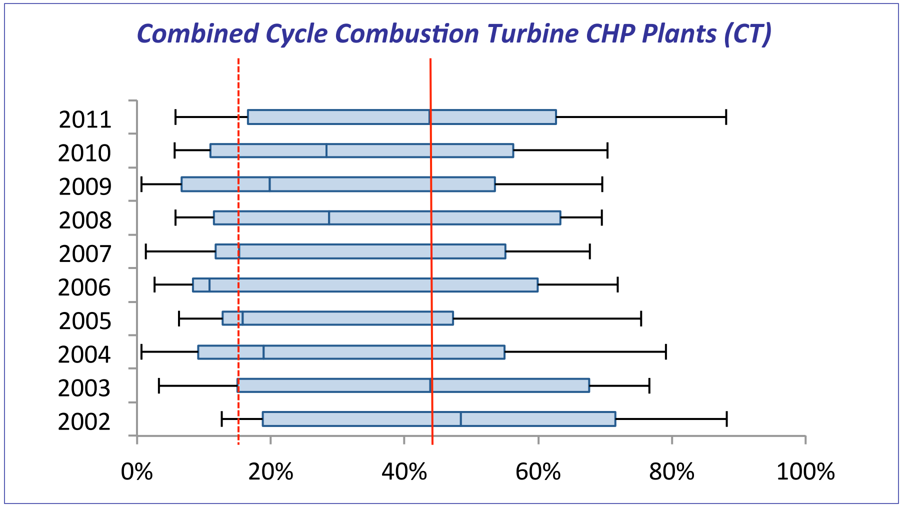
1. Yearly Median CF has been between 50% to 60%
2. Median CF in the last 3 years (2011, 2010 & 2009) has been lower than that for earlier years
3. Generally in each of the year, only about 25% of plants (Q4 – 4th quartile in the box and whisker diagram) are able to operate at CFs greater than around 70%
4. And another 25% of plants (Q1) operate at CFs of just between 0% to 30%
5. CF for all plants at an average for last ten years has been 48%

Capacity Factor distribution according to Technology Type

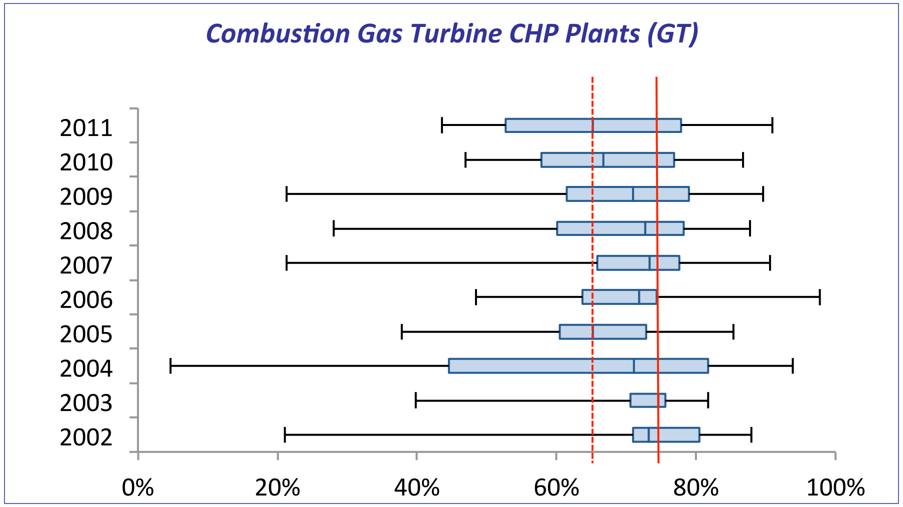
48 No. of plants
Capacity > 1 MW

Type of Prime Mover	No. of plants
CT (Combined Cycle Combustion Turbine)	**20**
GT (Combustion Gas Turbine)	**11**
IC (Internal Combustion Engine)	8
ST (Steam Turbine)	9

Type of Prime Mover	CT
Min CF	1%
Avg. CF	35%
Max CF	88%
Median Range	11% - 48%



Type of Prime Mover	GT
Min CF	5%
Avg. CF	67%
Max CF	98%
Median Range	65% - 73%



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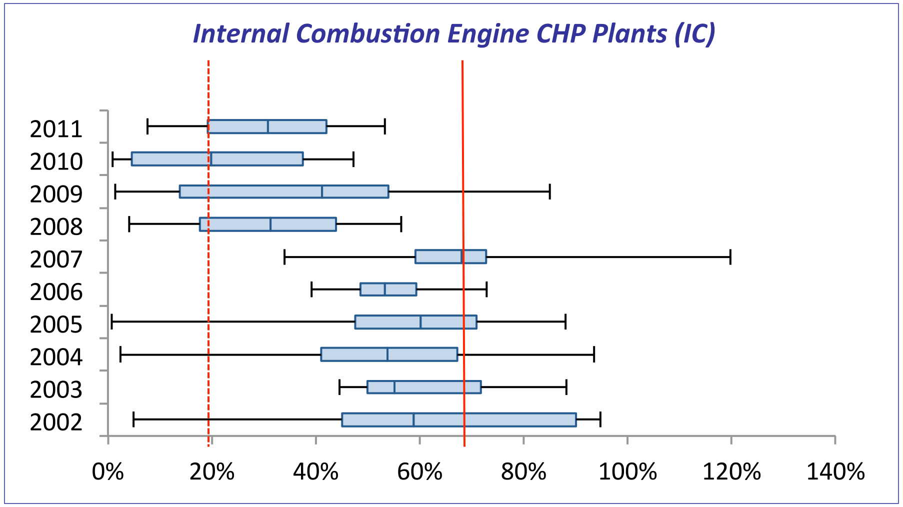
Capacity Factor distribution according to Technology Type

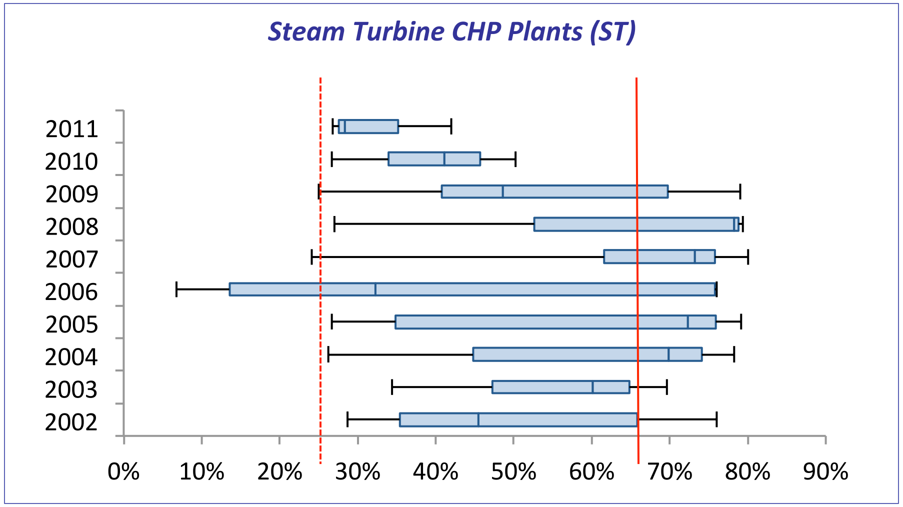
48 No. of plants
Capacity > 1 MW

Type of Prime Mover	No. of plants
CT (Combined Cycle Combustion Turbine)	20
GT (Combustion Gas Turbine)	11
IC (Internal Combustion Engine)	**8**
ST (Steam Turbine)	**9**

Type of Prime Mover	IC
Min CF	1%
Avg. CF	48%
Max CF	94%
Median Range	20% - 68%



Type of Prime Mover	ST
Min CF	7%
Avg. CF	51%
Max CF	80%
Median Range	28% - 78%



Capacity Factor distribution based on type of facility

Type of Facility $	No. of plants #	Capacity (MW) #	Min CF	Avg. CF	Max CF
Chemicals	11	1,213	8%	54%	94%
Refining	4	1,306	3%	46%	88%
University	3	16	21%	63%	98%
Printing/ Publishing	3	6	31%	45%	60%
Food Processing	2	23	53%	60%	88%
Office Building @	2	80	50%	69%	76%
Solid Waste Facilities	2	75	76%	91% *	120%
Instruments	1	140	1%	6%	11%
Justice/ Public Order	1	4	74%	80%	86%
Pulp & Paper	1	157	6%	13%	16%
Wastewater Treatment	1	156	3%	14%	39%
Others	17	2,480	1%	33%	90%

* Calculation of Avg. CF takes into account the max data point of value 120%

By taking all data points = CF of all plants in all years, as available

e.g. Ocean County Landfill (4.8 MW), American Ref-Fuel of Essex (70 MW)

Hunterdon Cogen Facility 4.1 MW

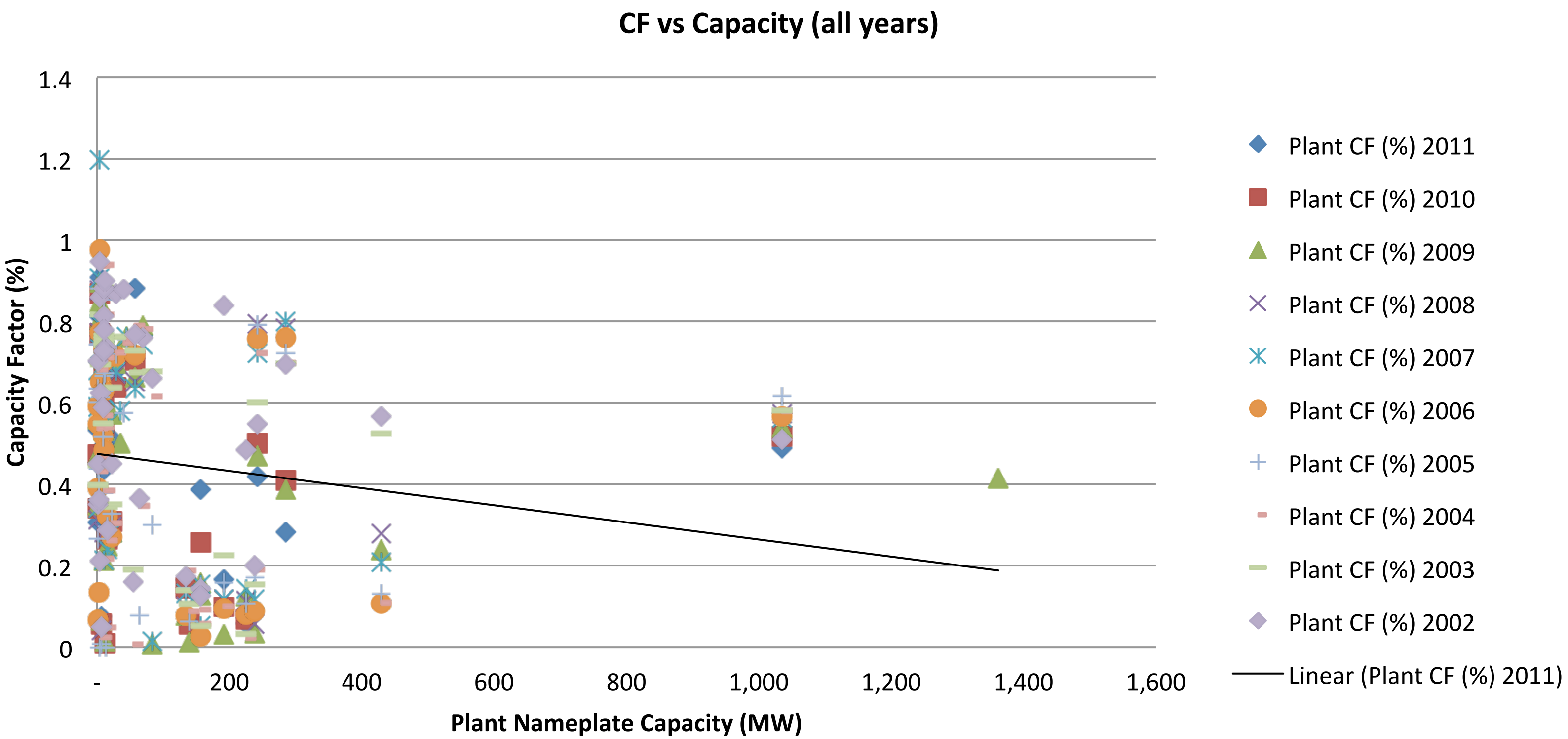
Includes Eagle Point Cogen, Lakewood Cogen, NAEA Lakewood, Prime Energy LP, RPL Holdings, Newark Power Plant etc.

$ Type of Facility has been identified using the ICF database for DOE - http://www.eea-inc.com/chpdata/

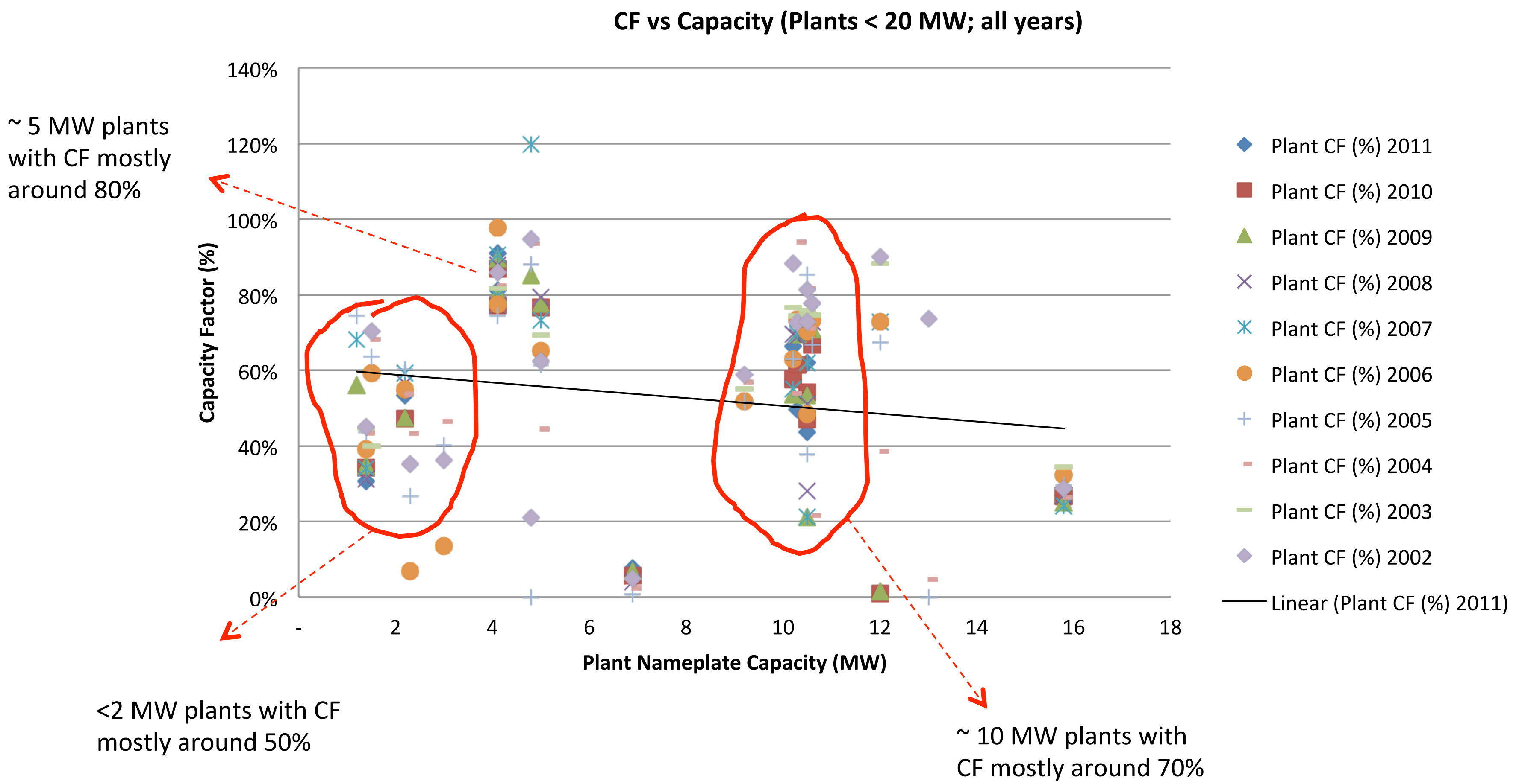
In case where a particular plant was not available in ICF database, the facility type has been either assumed (on the basis of its name) or has been clubbed under the type 'Others'.

@ It appears that ICF classifies 'type' depending upon the end-use of generated power. For e.g. it classifies 'Camden Resource Recovery Facility' as an 'Office Building' – when in fact the CHP plant is been developed as part of a solid waste treatment facility.

Capacity Factor distribution based on Plant nameplate capacity and year of operation (all plants in NJ database)



Capacity Factor distribution based on Plant nameplate capacity and year of operation (plants < 20 MW)



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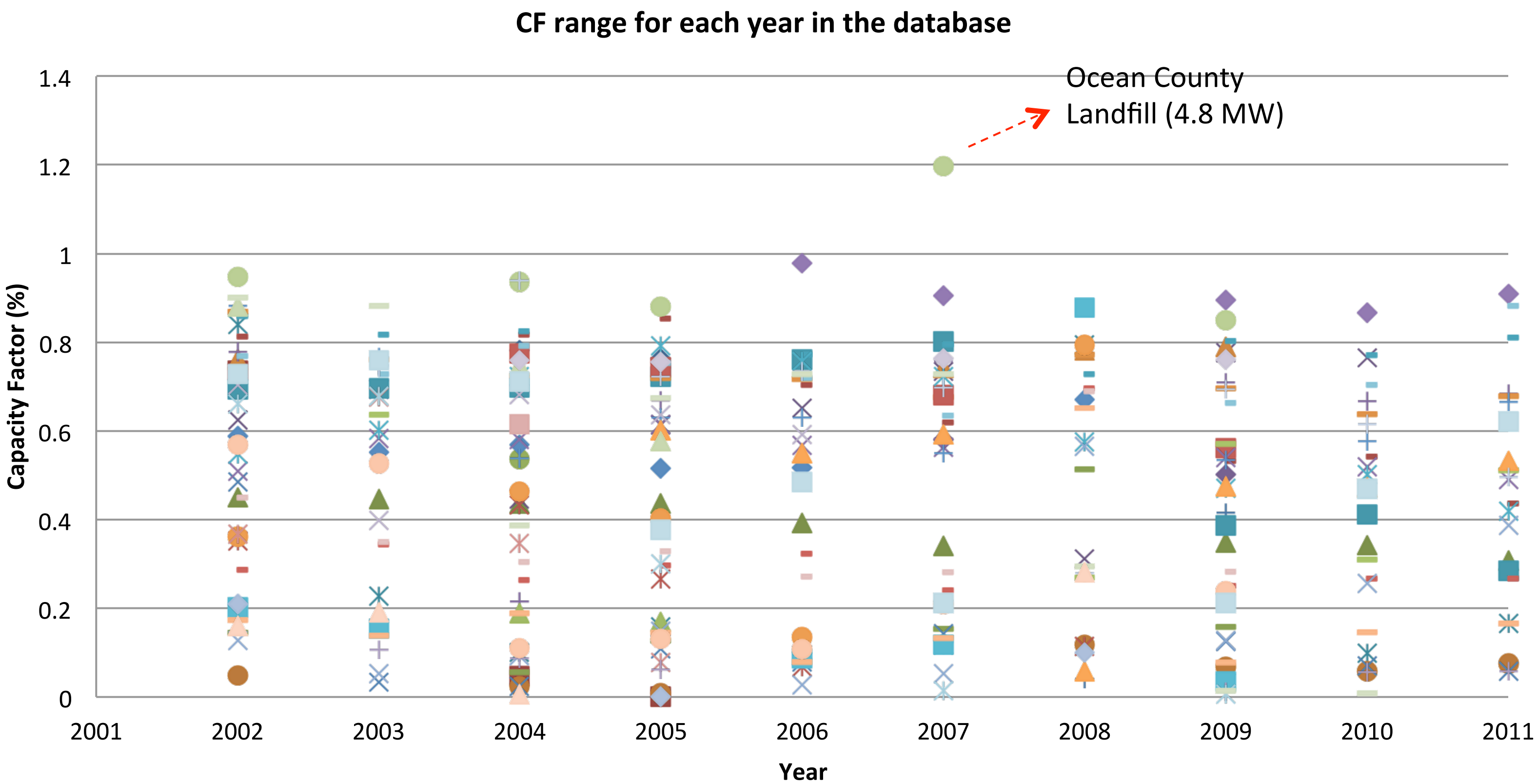
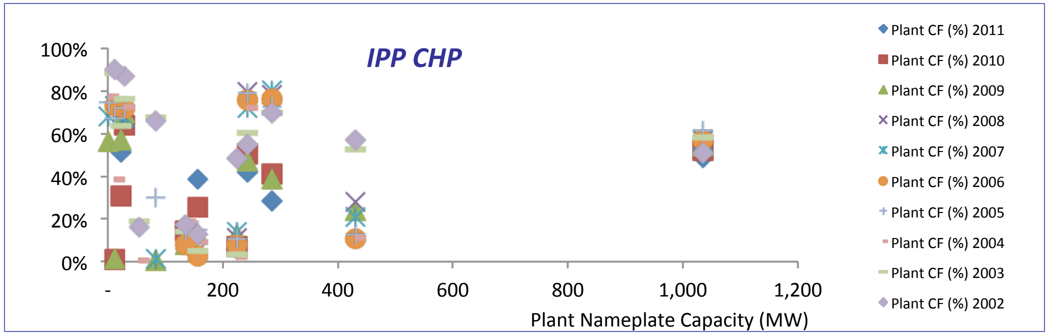
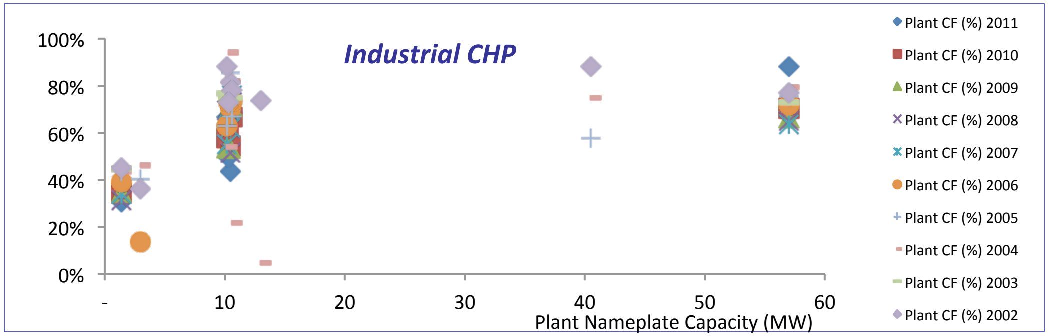
Range of Capacity Factor distribution for each year in the database

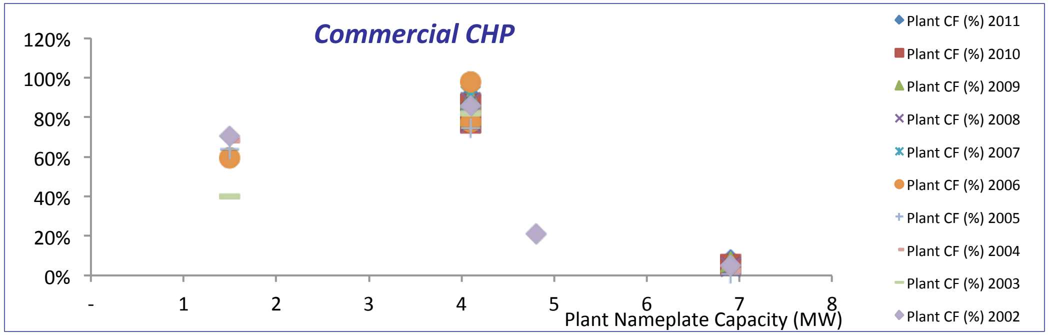


* Symbols in chart represent different units

Capacity Factor distribution based on facility category







IPP CHP: Number of plants = 13

Avg CF = 42% and Median CF = 32%

Industrial CHP: Number of plants = 9

Avg CF = 61% and Median CF = 50%

Commercial CHP: Number of plants = 5

Avg CF = 60% and Median CF = 49%

- Facility category is reported in EIA Form 860, which states: *IPP CHP – plants whose primary purpose is to produce electricity for public sale; Commercial & Industrial CHP – where the CHP facility is usually intended to provide electricity and steam to the host facility, such as a factory.*
- Information was available for 27 plants out of the list of 48 plants in NJ.

We have looked at some previous public studies to understand the CF distribution for CHP plants – based on a) type of technology b) time of year

1) Studies reporting CFs of CHPs in the state of California
    - Navigant : CHP Performance Investigation – for California Self-Generation Incentive Program, April 2010
    - ITRON - CPUC Self-Generation Incentive Program Ninth-year Impact Evaluation, June 2010
2) Studies reporting CFs of CHPs in the state of Massachusetts
    - KEMA - Massachusetts CHP Evaluation Methodology and Analysis Memo, Jan 2012

Navigant reports Capacity Factor distribution for CHPs based on technology type in the state of California

Table 10. Average capacity factor, as a percent of rated capacity, by technology type and year of installation

PA		Install Year[1] 2002	2003	2004	2005	2006	2007	2008	*All Years*
Fuel Cell	average capacity factor	86%			72%	72%	82%	91%	76%
	number of sites	1	0	0	2	7	1	1	12
Internal Combustion Engine	average capacity factor	22%	34%	29%	38%	30%	33%	29%	31%
	number of sites	16	43	34	21	8	6	1	131
Microturbine	average capacity factor	33%	30%	40%	49%	70%	39%		41%
	number of sites	10	19	7	16	6	4	0	62
Gas Turbine	average capacity factor			71%	85%	76%			77%
	number of sites	0	0	1	1	1	0	0	3
All Types	average capacity factor	28%	33%	32%	45%	56%	40%	60%	37%
	number of sites	27	62	42	40	22	11	2	208

Blue bars show the relative magnitude of values by PA and Install Year.

Red bars show the relative magnitude of values by PA, for all Install Years.

Green bars show the relative magnitude of values by Install Year, for all PAs.

[1]Counts and capacities reported for each install year are not cumulative.

SOURCE: Navigant : CHP Performance Investigation – for California Self-Generation Incentive Program, April 2010

ITRON provides Capacity Factor distribution data based on technology type in the state of California

Table 5-5: Annual Capacity Factors by CHP Technology and Fuel

2009 Technology	Annual Capacity Factor* (kWyear/kWyear)	
	Natural Gas	Renewable Fuel
FC	0.629	0.514 †
GT	0.863	NA
IC Engine	0.243 †	0.276 †
MT	0.429	0.223 †

* [a] indicates accuracy is less than 70/30.
† indicates accuracy is better than 70/30.
No symbol indicates accuracy is better than 90/10.

FC = Fuel Cell

GT = Gas Turbine

MT = Micro Turbine

SOURCE: ITRON - CPUC Self-Generation Incentive Program Ninth-year Impact Evaluation, June 2010

KEMA compares CF distribution for projects in MA & CA based on operation season (time of year)

Figure 1-1: Comparison of Daily Capacity Factor Profiles for IC Engines (MASS vs. SGIP by Season)

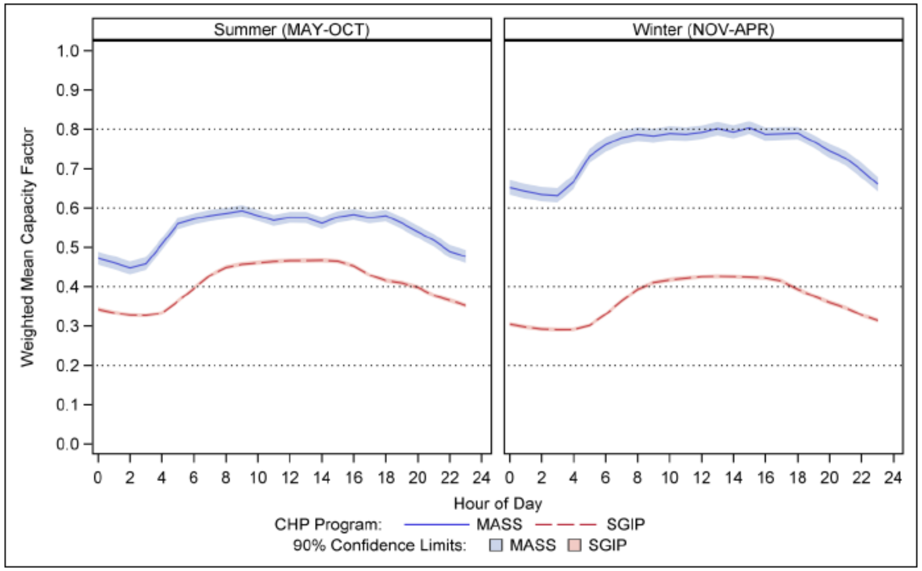
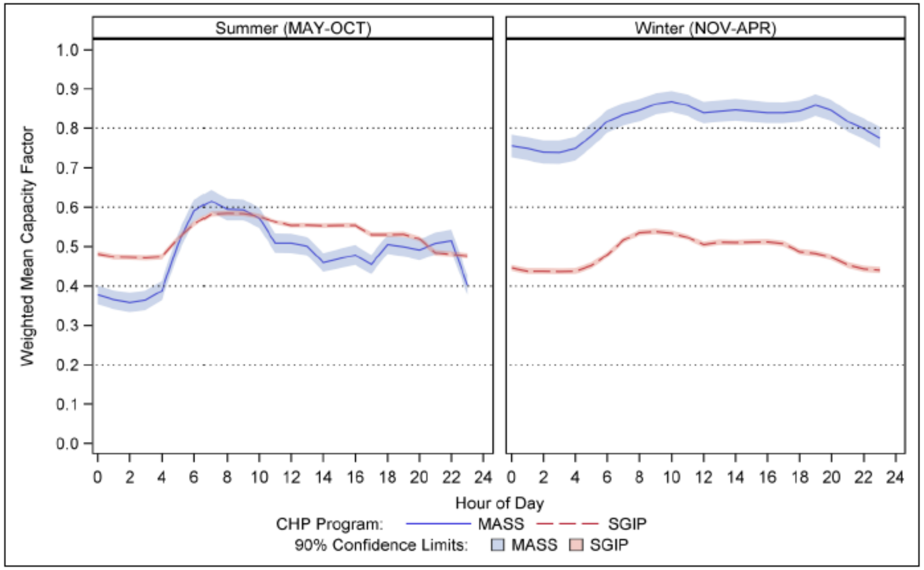


Figure 1-3: Comparison of Daily Capacity Factor Profiles for Microturbines (MASS vs. SGIP by Season)



SOURCE: KEMA - Massachusetts CHP Evaluation Methodology and Analysis Memo, Jan 2012

SGIP (Self-Generation Incentive Program)

MASS (Massachusetts CHP Program)

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Quantifying 'avoided T&D' benefit

'Avoided T&D' investment ben
range from 0% - 100% - depen
stakeholder logic/ argument

Not to write in argument for any party. Just explain two cases 0% and 100% benefits.

Utility's argument:

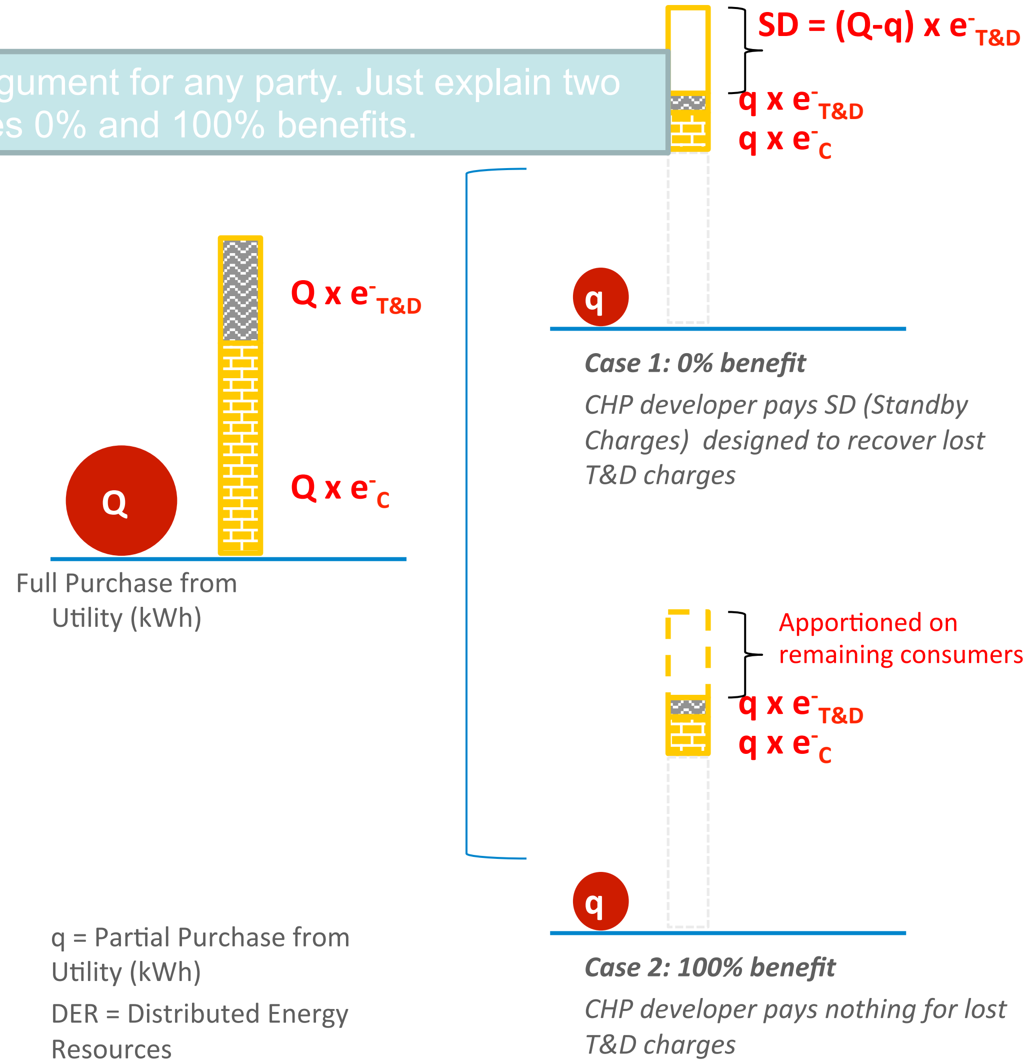
- No T&D avoidance
- Utility has to plan for meeting full load during CHP outage period
- Network investment since already incurred, needs to be recovered (assuming a flat load growth y-o-y and therefore 'lost' recovery cannot be made from new connected load)

CHP developer's argument:

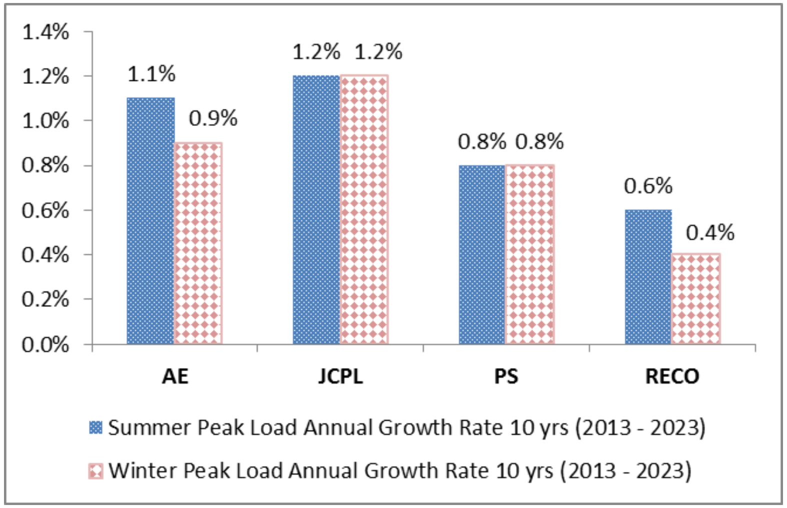
- Demand during CHP outage can be met with the same network ---> as not all customer outages will coincide in time

Other Ratepayer's argument:

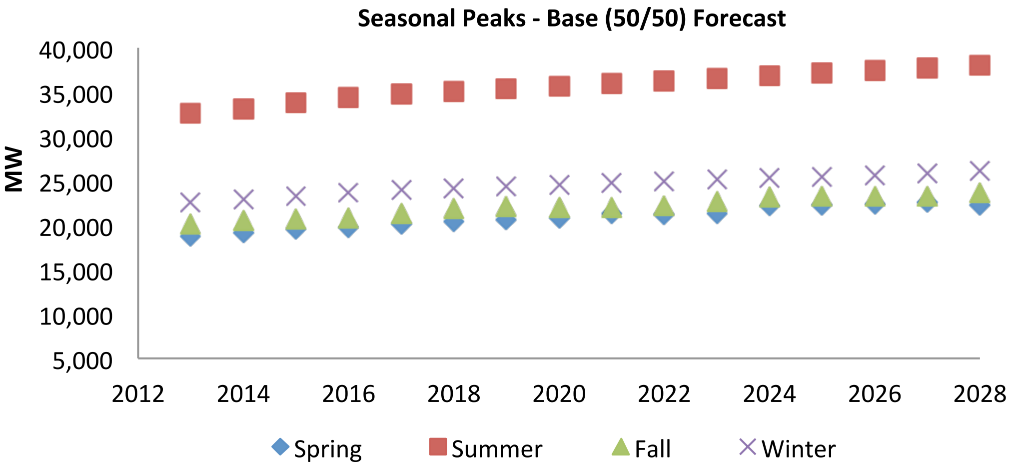
- Tariff increase (due to cost apportionment on remaining customers) leads to a vicious cycle of more DER & further tariff increases

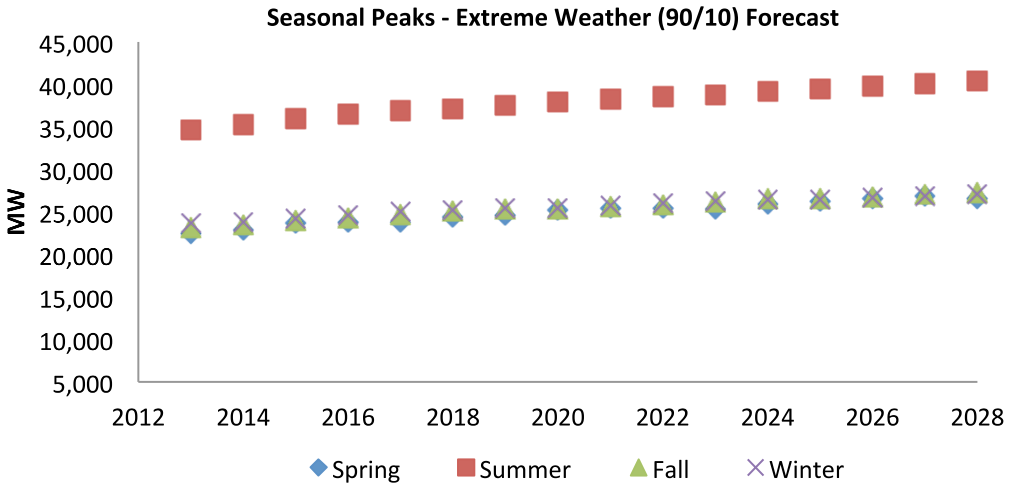


Load growth in NJ over the next ten years is expected to be slow – even under extreme weather conditions



Source: PJM Load Forecast Report - Jan 2013





AE Atlantic Electric zone (part of Pepco Holdings, Inc.)
JCPL Jersey Central Power & Light zone
PS Public Service Electric & Gas zone
RECO Rockland Electric (East) zone (incorporated 3/1/2002)

Source: PJM Load Forecast Report - Jan 2013

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‘Probability’ and ‘Period’ of outage are difficult to project

‘Value of Loss Load’ is facility dependent

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Response to stakeholder comments received

S.No.	Comment Received	CEEEP Response
1.	RC: Key Assumptions – Financial Assumptions "CEEEP should consult with various stakeholders such as CHP project developers, lenders, and investors to learn NJ-specific financial data, including the debt/ equity ratio, equity rates, loan rates, loan repayment, depreciation schedule, and construction period. "	Information obtained from past & current applications filed under the Large Scale CHP-Fuel Cells Program provides actual assumptions of developers in NJ and therefore is a good starting point for financial assumptions.
2.	RC: Key Assumptions – Standby Rates "CEEEP is planning to meet with utility staff to receive input on utility standby rates. Rate Counsel supports this approach as a way to develop standby rate assumptions for CEEEP's CBA model, but also suggests that CEEEP consult with Rate Counsel before finalizing standby rate assumptions."	Current study SOW involves making use of current utility standby rates for calculation purpose. Arriving at a methodology for standby charges is not within this study's scope of work.
3.	RC: Key Assumptions – Monthly Gas and Electric Peak and Usage "For monthly gas and electric usage data for large nonutility power producers, including CHP, Rate Counsel suggests CEEEP investigate U.S. EIA's 923 data, as this database is publicly available and contains data on CHP facilities in New Jersey. …. Rate Counsel does not have any data source for monthly peak usage data, but notes that monthly peak data as well as time of use and seasonal usage data (e.g., winter off-peak and peak, summer peak and off-peak) would be useful to estimate more accurate avoided costs and emissions for certain applications calling for a higher level of granularity."	CEEEP has investigated EIA Forms 923 and other public databases which provide historic operation information of large CHP plants. Analysis based on such investigation is included in this presentation. Pl note that the current version of CHP CBA is developed as a high-level stylized model and therefore does not take into account monthly and seasonal differences in electric & gas consumption. The key idea of this stylized model is to calculate costs & benefits at a conceptual level though it compromises on granularity.

Response to stakeholder comments received

S.No.	Comment Received	CEEEP Response
4.	RC: Key Assumptions - Capital Cost of Black Start Equipment “The U.S. EPA has compiled data on capital costs of equipment for black start capability. A summary of equipment cost from this database is provided below…..“	Since no particular back-up control level type has been identified while in calculations for the stylized model; therefore an assumption has been used which falls between the range of capital costs as confirmed from various sources. Users can change this assumption based on the type of B/S capability they propose to use.
5.	RC: Key Assumptions – Value of Loss Load “Loss of load value varies widely by type of customer. …. Accordingly, Rate Counsel does not recommend that CEEEP use a single value for the value of loss of load in its analysis. An analysis similar to PG&E’s should be performed based on New Jersey data. CEEEP should recognize the variation in this value based on type of business or sector within its CBA, which could then be extrapolated to a state-wide basis based on CHP market potential by SIC code.”	As Rate Counsel has rightly suggested that the VOLL is extremely customer-specific. Further the current study does not involve calculating VOLL for different types of customers in NJ. Therefore a hypothetical VOLL assumption has been used and again which the user can change according to his/her business/ usage.
6.	RC: Comments on additional issues – CBA Perspective “The current proposal misses the utility/ratepayer perspective, which means that the model cannot calculate the economics of CHP as a utility investment of ratepayer funds. …. To assess what level of incentives provides the best return on utility/ratepayer investments, the utility perspective is necessary in the CBA model.”	Model is being modified from rate payers perspective.

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Response to stakeholder comments received

S.No.	Comment Received	CEEEP Response
7.	RC: Comments on additional issues – Standby Charge "However, to the extent that standby charges represent true costs to the utility, <u>they should be counted as costs from the societal perspective, which will essentially reduce the amount of avoided transmission and distribution costs</u>. This is a complex issue. Thus, we encourage CEEEP and CEP staff to have discussions with utility staff and consult with Rate Counsel on this subject."	Standby charges have been considered as a cost to the CHP project developer who is part of the society.
8.	RC: Comments on additional issues – Avoided Emissions " … Rate Counsel is concerned with this method as it may not accurately estimate avoided emissions, and potentially over-estimates avoided emissions, because <u>it assumes that CHP can displace all of marginal coal generation</u>. … <u>Emission rates within the PJM territory</u> should be readily available. In general, CEEEP should use or develop temporally and geographically differentiated avoided emission data. "	The stylized model takes into account PJM actual marginal rum power plant data for 2012. Depending upon the number of hours of operation of a CHP plant, the model calculates which type of marginal plant (coal, gas or oil) would be displaced by the CHP.
9.	RC: <u>Additional resources</u> – KEMA 2008 Market potential of Combined Heat and Power in Massachusetts and EPRI 2008, Creating Incentives for Electricity Providers to Integrate Distributed Energy Resources	

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Response to stakeholder comments received

S.No.	Comment Received	CEEEP Response
10.	NJ Clean Energy Ventures : Provided their project cost ($/KW and $/kWh) as a reference point	The stylized model is built as such that the user can change/ modify the input assumption for CHP Capital Cost and Operating Cost as per his/ her understanding.
11.	Capstone Turbine: "On slide 5, one of the social benefits missing for CHP is increased efficient use of fuel, which allows more value to be derived from this natural resource."	We recognize 'increased efficient use of fuel' as a benefit offered by CHP and it gets captured in the stylized model.
12.	Capstone Turbine: "In the technology emissions tables, it would provide broader representation of CHP technologies if a 1 MW microturbine system was used instead of a 1 MW recip. Capstone publishes tech specifications for microturbines at ww.capstoneturbine.com<http://www.capstoneturbine.com/> in the Document Library."	Table is for illustration purpose only.
13.	Capstone Turbine: "On slide 7, for a 1 MW CHP microturbine system operating at 70% efficiency, the emissions rate for CO2 is 625 lbs/MWh. It is not clear at what level of efficiency the other systems are operating."	Slide 7 does not depict any data for a microturbine system.
14.	Capstone Turbine: "On slide 8, a 1 MW CHP microturbine system has a NOx emissions rate of 0.19 lbs/MWh."	Slide 8 does not depict any data for a microturbine system.

Response to stakeholder comments received

S.No.	Comment Received	CEEEP Response
15.	Capstone Turbine: "On slide 9, a reference is made to the need to include particulate emissions. For a 1 MW CHP microturbine system, the emissions rate for VOC expressed as methane (THC) is 0.047 lbs/MWh or for a low emissions system, 0.018 lbs/MWh."	Noted.
16.	Capstone Turbine: On CHP Database – "1. ICF is currently updating its CHP technology comparisons for DOE. 2. LHV is a more typical efficiency reference (vs HHV) for the CHP industry unless fuel input is being considered."	Noted. Fuel input is being considered as part of the stylized model.
17.	Veolia Energy North America : "Our principal comment is that we believe your assumed capital costs and O&M costs for Combined Heat and Power are significantly below what we have been facing in the real world markets of the Northeast and particularly in the urban environment that characterizes much of New Jersey. Our operating assumptions for CHP Projects of the size that we typically seek out, approximately 5-15 MW, are typically in the range of from $2,000/kW for a basic greenfield project to $4,000/kW or more for a more complicated project (which most projects are). With respect to CHP O&M costs, these broadly speaking can range anywhere from around 2 to 4 cents per kWh – depending on the type of prime mover, prime mover size, level of warranty, staffing requirements vs. remote monitored, etc."	The stylized model is built as such that the user can change/ modify the input assumption for CHP Capital Cost and Operating Cost as per his/ her understanding.

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Response to stakeholder comments received

S.No.	Comment Received	CEEEP Response
18.	Veolia Energy North America : "Our second comment concerns the CEEEP's draft Avoided Cost Assumptions, July 2013. We particularly question the assumed $30/kW-year for Avoided Electric Transmission and Distribution (T&D). The New York State Energy Research and Development Authority (NYSERDA) published a study in 2011, "Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies", which found that avoided Distribution Capacity costs could range as high as $110/kW-yr. Pace University's Energy Project reportedly believes that a better estimate would be almost double, i.e., NYC avoided distribution costs on average are now believed to be $200/kW-year. One of the major benefits of CHP, as you know, is the avoidance of T&D costs that CHP enables by siting CHP generation close to load. Getting this component of your study correct is an important element of the CBA."	
19.	Veolia Energy North America : "Finally, Veolia has a major concern that your study may not be giving enough weight to the societal benefits of CHP. You are well aware of the significant job creation, economic growth, greenhouse gas emission reductions, national security and enhanced grid reliability and storm proofing that CHP delivers. Please ensure that these societal benefits are fully accounted for in your CBA. While quantifying these positive externalities may not be easy, they are nevertheless critically important to a full and fair analysis. "	The stylized model takes into account society costs and benefits.

AGENDA

1. Explaining how the CHP Stylized Model works
2. Points for discussion
   1. Capacity Factor assumptions
   2. Quantification of T&D avoided cost benefits
   3. Reliability benefit calculation assumptions
3. Response to stakeholder comments received
4. Next Steps

We would like to thank the Rate Counsel, Gearoid Foley, Anne-Marie Peracchio (NJNG), TRC for their time and valuable inputs.

Note: References used and other reports by CEEEP can be found at http://policy.rutgers.edu/ceeep/chp

Next Steps

1. Incentive applicability in case of changed scenarios of CF?
2. T&D benefit calculation?
3. VOLL assumptions?

Thank You