RUTGERS

Edward J. Bloustein School
of Planning and Public Policy

Combined Heat and Power Cost-Benefit Analysis and Discussions on Quantification of Uncertainties

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Draft v.1

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AGENDA

1. Key Inputs into the CHP Cost-Benefit Analysis Model
2. Major Assumptions and Quantifying Uncertainties
3. Response to stakeholder comments received
4. Next Steps

This presentation and the CHP Cost-Benefit Analysis "Stylized Model" was prepared by CEEEP in the course of performing work contracted for and sponsored by the NJ Board of Public Utilities.

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

References used and other reports by CEEEP can be found at http://ceeep.rutgers.edu/combined-heat-and-power-cost-benefit-analysis-materials/

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

SOCIETY

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

OWNER

COSTS

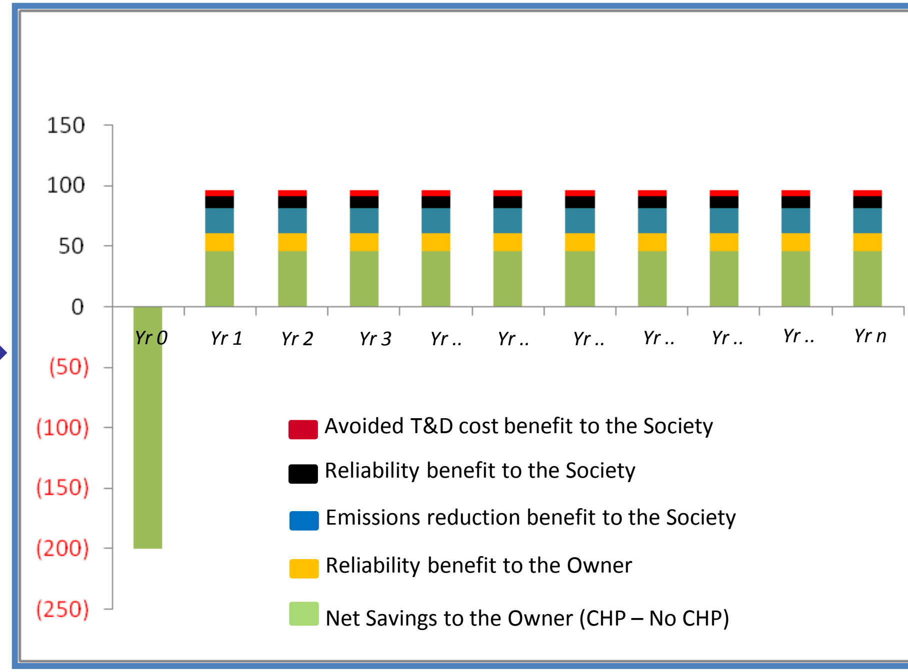
- ✓ Capital Costs
- ✓ Fuel Costs
- ✓ O&M Costs

BENEFITS

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

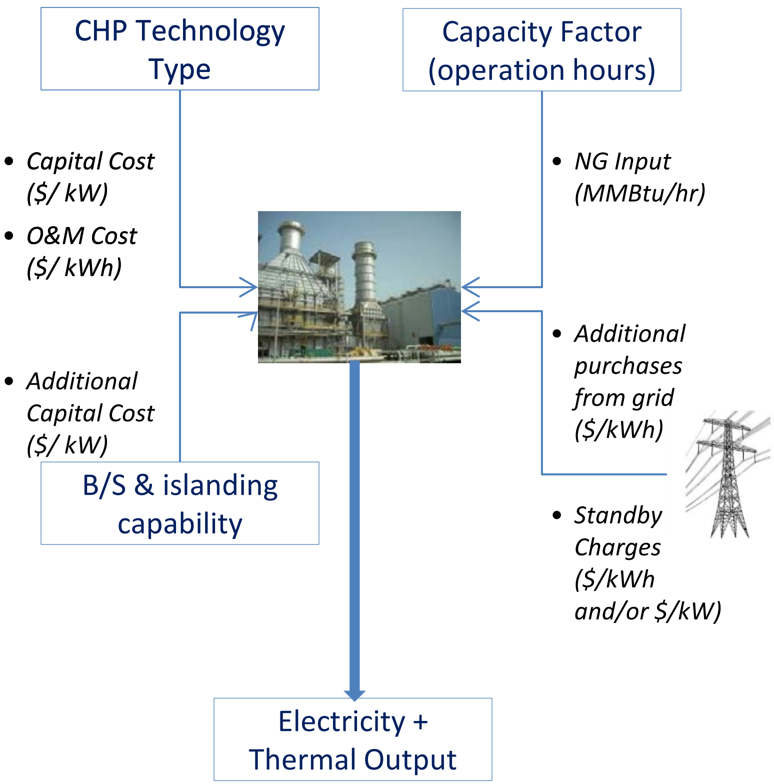
There could be some macroeconomic effects (such as job growth) which could be positive or negative

Net Benefits to Society (Quantifying Costs & Benefits)



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

Identifying key inputs into the CBA Model



- *Avoided electricity and NG purchase ($/kWh and $/MMBtu)*
- *Reliability Benefits ($/kWh)*
- *Emissions reduction Benefits ($/kWh)*

Cash Flow Statement	**Yr_1**	**Yr_2**	**….**	**Yr_n**
Costs:				
1 • Capital Costs (+ for B/S & islanding)				
• Operating & Maintenance Costs				
2 • Fuel Cost (dependent upon CF & price)				
• Additional e- purchase costs				
3 • Standby Charges				
Savings:				
• Avoided electric & NG purchase costs				
4 • Reliability benefit (Value of Loss Load)				
• Emissions reduction benefit				
Net Benefit = Savings - Costs				

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1 Project complexity and location does have an effect on the installed capital costs

Applicant Name (Source: BPU Order dated Dec 19, 2013 and Jan 23, 2013)	**Installed Capacity (MW)**	**Prime Mover Type**	**Application quoted – Capital Cost ($/kW)**	**Comparable Tech Size**	**National Average Capital Cost ($/kW) ***	**Source**	**Factor** (times the national average costs)
AtlantiCare Regional Medical	1.10	RE	3,182	1 MW	1,671	SENTECH, 2010	1.9
Monmouth Medical Center	3.00	RE	2,222	3 MW	1,515	ICF, 2012	1.5
New CMC	3.00	RE	2,305	3 MW	1,515	ICF, 2012	1.5
Bristol Meyer's Squibb	4.11	RE	2,263	5 MW	1,515	ICF, 2012	1.5
UMM Energy Partners	5.67	CT	4,680	5.67 MW	1,336	SENTECH, 2010	3.5
Nestle Inc.	7.96	CT	1,905	10 MW	1,588	ICF, 2012	1.2

** $2012 adjusted @2.2% GDP Deflator*

1. Industry experts advise caution while using **'plain vanilla' costs** in widely quoted reference studies, such as the EPA Catalog and others as mentioned in the table above.
2. EPA Catalog notes that " ….. It should be noted that **installed costs can vary significantly** depending upon on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirements, prevailing labor rates, whether the system is a new or retrofit application, and whether or not the site is a green field or is located at an established industrial site with existing roads, water, fuel, electric etc."

2 Historical information of CHP plant performance has been collated using various sources (1/6)

S.No.	Data / Information	eGRID	EIA	ICF
1.	Name of the CHP Plant	✔	✔	✔
2.	Location of the CHP Plant (State, County)	✔	✔	✔
3.	Name of the CHP Plant Operator	✔	✔	✔
4.	Plant Nameplate Capacity	✔		✔
5.	Prime Mover Technology of CHP		✔	✔
6.	Capacity Factor	✔		
7.	Primary Fuel used	✔		✔
8. a	Net Generation - Annual	✔	✔	
8. b	Net Generation - Monthly (for each generator/ unit)		✔	
9. a	Heat Input - Annual	✔	✔	
9. b	Heat Input - Monthly (for each boiler/ unit)		✔	
10.	NAICS Code		✔	✔
11.	Application/ Usage			✔

CHP Database
(plants with installed capacity > 1 MW)

Source of information:

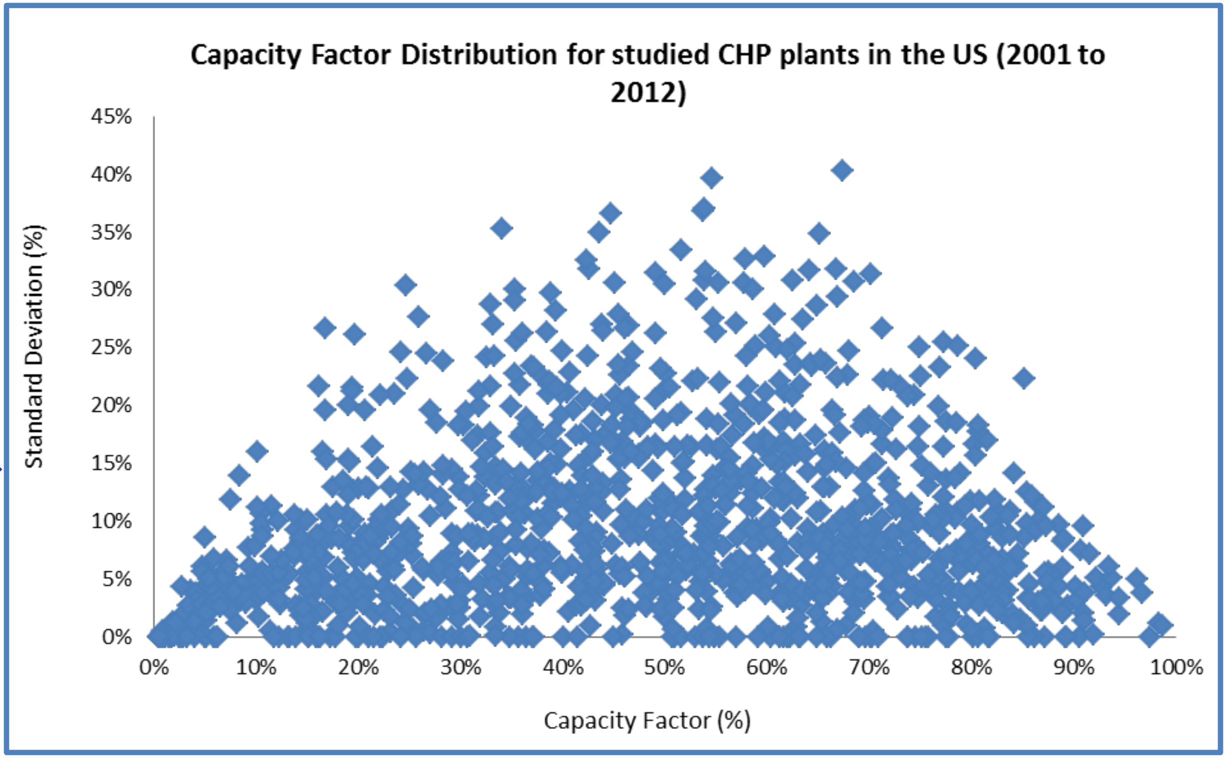
- **eGRID Data files** for years 2009, 2007, 2005 & 2004
- **EIA (Survey Form 923)** for years 2012, 2011, 2010, 2008, 2006, 2003, 2002 & 2001
- **ICF CHP database** http://www.eea-inc.com/chpdata/

Actual capacity factor of CHP plants is lower than normally expected and exhibit large standard deviation (2/6)

CHP Database
(plants with installed capacity > 1 MW)

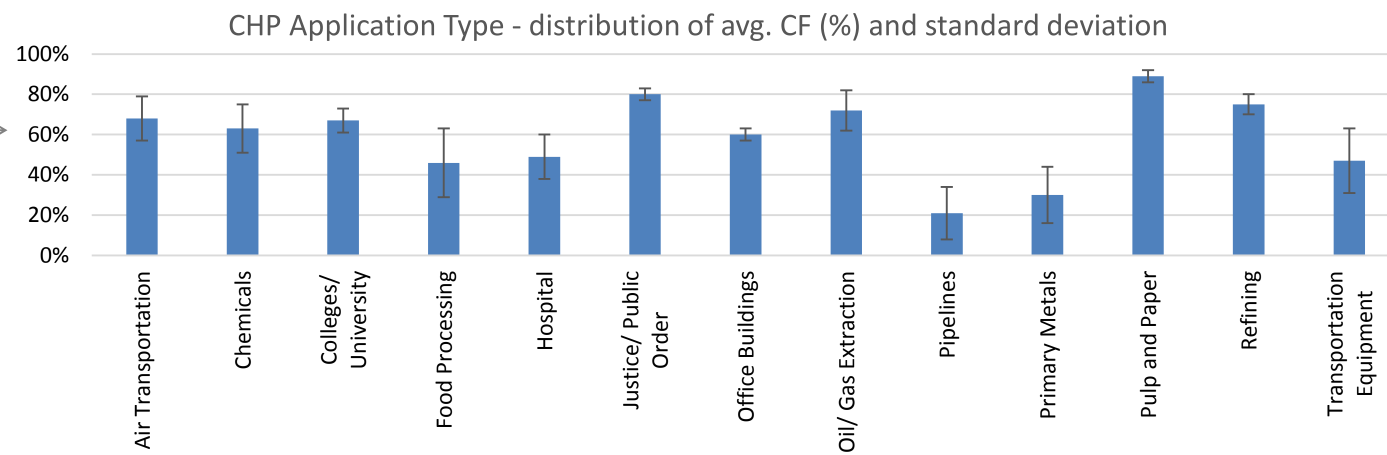
Capacity Factor calculation: for a particular year, for a particular plant

$$\text{CF} = \frac{Actual\ Generation\ (kWh)}{Plant\ Capacity\ (KW) * 8760}$$



Data segmentation does not lead to any specific correlation results (3/6)

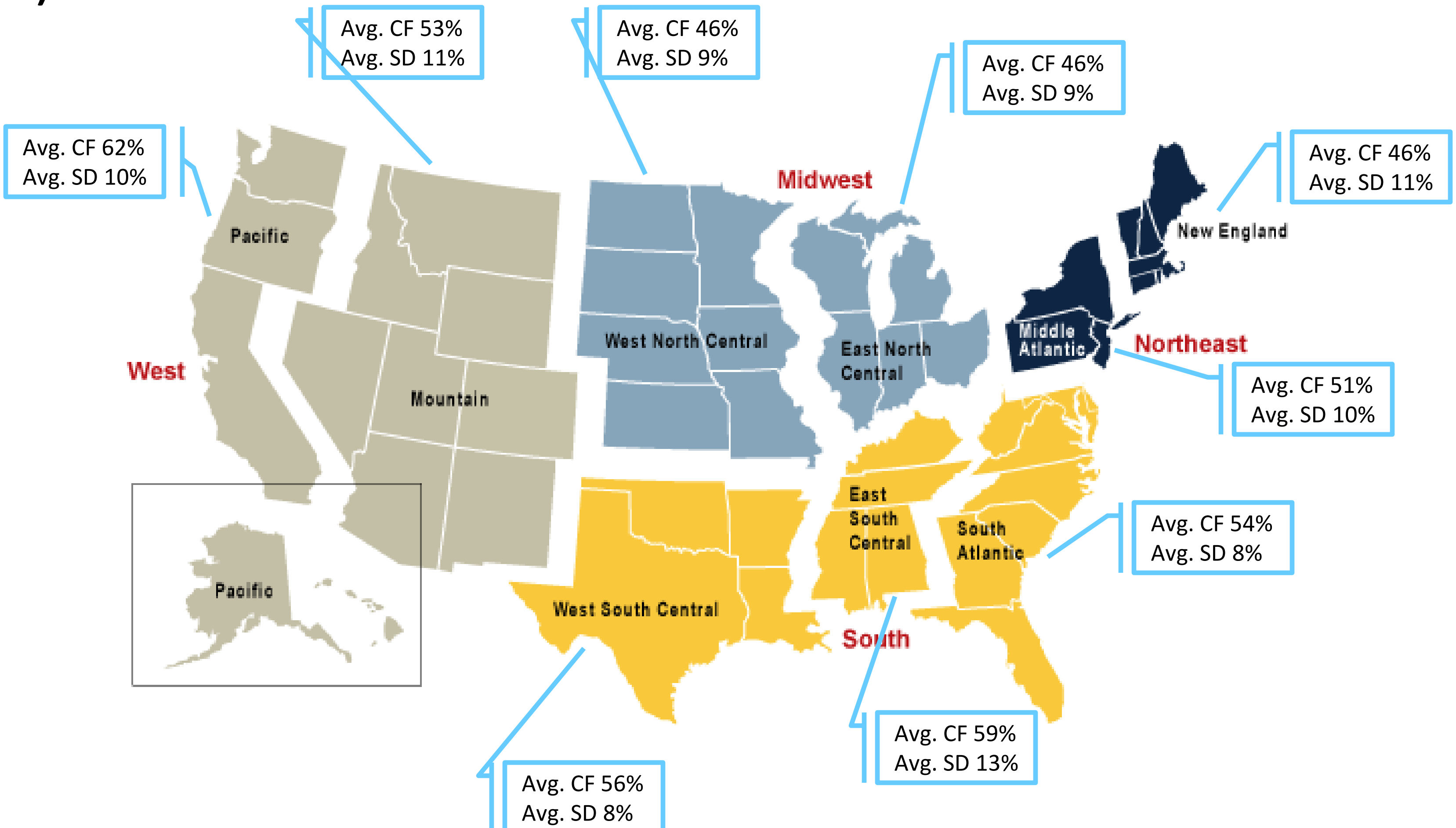
S. N.	Data Segmentation	No. of Plants	Avg. of avg. CF	CF Std. Dev. Avg.	CV*	Comments
A	All plants	1251	47%	9%	19%	Complete Data Set
B	A. Post excluding data for 1st year	1152	47%	9%	19%	To account for the fact that a plant need not have necessarily started operations on 1st of January
C	Out of B only those with complete 12 years data	330	55%	10%	18%	To account for absence of information for certain plants
D	Out of C only those with capacity < 30 MW	106	52%	9%	17%	To exclude probable PURPA plants which might have been installed for different reasons
E	Out of D only those having one single Prime Mover type across all units	87	56%	9%	16%	To exclude for any differences due to the prime mover type
F	Out of E only those using NG as fuel	56	59%	10%	16%	To bring further homogeneity to the group
G	Out of F only those with CT or GT as Prime Mover	42	62%	10%	16%	To bring further homogeneity to the group



* Coefficient of Variation
= Std. Deviation / Mean

$$\mathrm{cv} = \frac{\sigma}{\mu}$$

Regional distribution of historical CHP plant* performance (4/6)

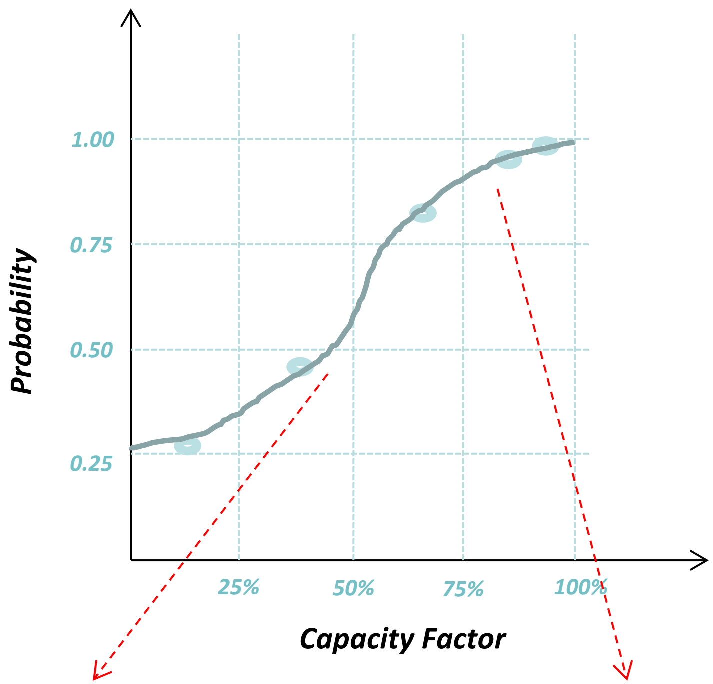


* for plants with all 12 years data (Row C in Table on slide 9)

Data suggests that probability of running a plant at very high capacity factor is rather low (5/6)

Segregating data points – FOR NEW JERSEY ONLY	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 – for NJ



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

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

2 Some state-specific studies in the past have reported low capacity factors for CHPs (6/6)

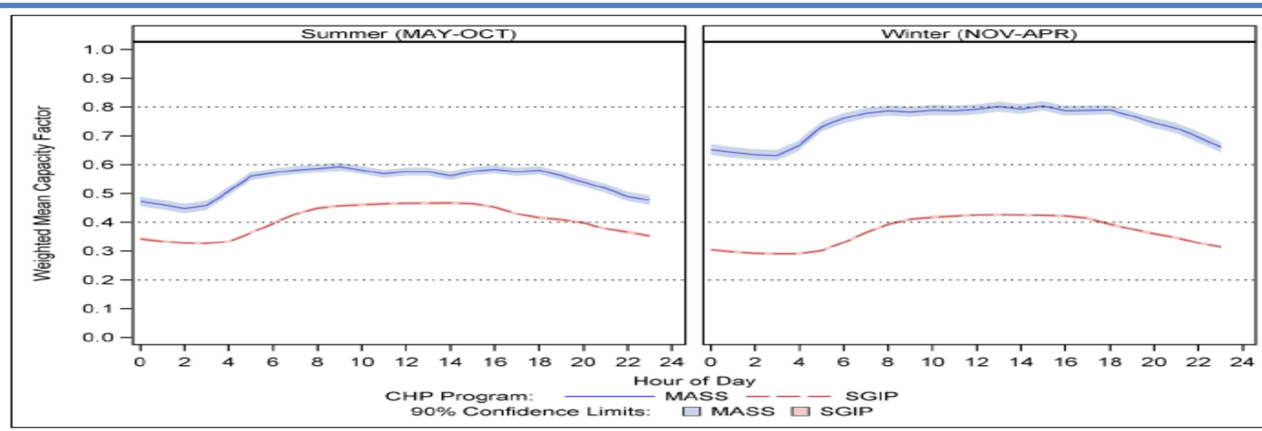
Navigant, 2010

CHP Performance Investigation – for California Self-Generation Incentive Program

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

KEMA, 2012

Massachusetts CHP Evaluation Methodology and Analysis Memo



3 Getting avoided T&D right is necessary to avoid cost shifting (1/3)

CHP Pays T&D Charges

Avoided T&D	**YES**	**NO**
YES	**Costs shifted** to CHP from other ratepayers	No Cost shifting
NO	No Cost shifting	**Costs shifted** to other ratepayers from CHP

T&D investments are typically lumpy, have economies of scale, and costs are primarily determined by capacity not through put.

3 Studies show an extremely wide range of avoided T&D costs (2/3)

Avoided Energy Supply Costs in New England: 2013 Report by Synapse Energy Economics, Inc.

Company	Year $	Transmission $kW-year	Distribution $kW-year	Methodology
CL&P	2013	$1.30	$30.94	ICF Tool
WMECO	2011	$22.27	$76.08	ICF Tool
NSTAR	2011	$21.00	$68.79	ICF Tool
National Grid MA	2013	$88.64	$111.37	ICF Tool
National Grid RI	2013	$20.62	$20.62	ICF Tool
PSNH	2013	$16.70	$53.35	ICF Tool
United Illuminating	2013	$2.64	$47.82	B&V Report
United MA	2013	NA	$171.15	ICF Tool
United NH	2013	$73.03	$29.26	ICF Tool
Vermont (statewide)	2012	$48.00	$102.00	Historical
Burlington Electric Deptt.	2012	$48.00	-	Historical

- *ICF Tool = ICF workbook developed in 2005*
- *B&V Report = United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009*

1. For the 2013 study report, Synapse surveyed the sponsoring electric utilities (table ref)
2. ICF Tool / workbook was developed by ICF for the 2005 Avoided Energy Supply Costs study
3. The tool was an Excel workbook, which allows participants to calculate their marginal costs
4. Participants need to provide:
   1. T&D investments – 15 historical years and 10 forecast years (e.g. $100 historical, $50 forecast)
   2. Specify the share of total investment which is related to load growth (default entry 50%)
   3. Estimates for carrying charges – which include insurance, taxes, depreciation, interest and O&M (e.g. 20%)
   4. Peak load growth – 15 historical years and 10 forecast years (e.g. incremental growth historical 10 KW, and incremental growth forecast 5 KW)
   5. Marginal cost historical = (100 *50% * 20%)/10 = 1
   6. Marginal cost forecast = (50 *50% * 20%)/ 5 = 0.5
   7. Avoided capacity cost = 1.5 $kW-year

3 PSE&G structure of standby charges recovers T&D costs during shutdown of CHP plant (3/3)

Assumptions	
CHP Capacity - kW	100
Generation Obligation	125.21
Transmission Obligation	108.75
No. of CHP outages (1 day per each summer month)	4
CHP Lost Outage kWh	9,600
CHP Outage Duration (hours- each day)	24

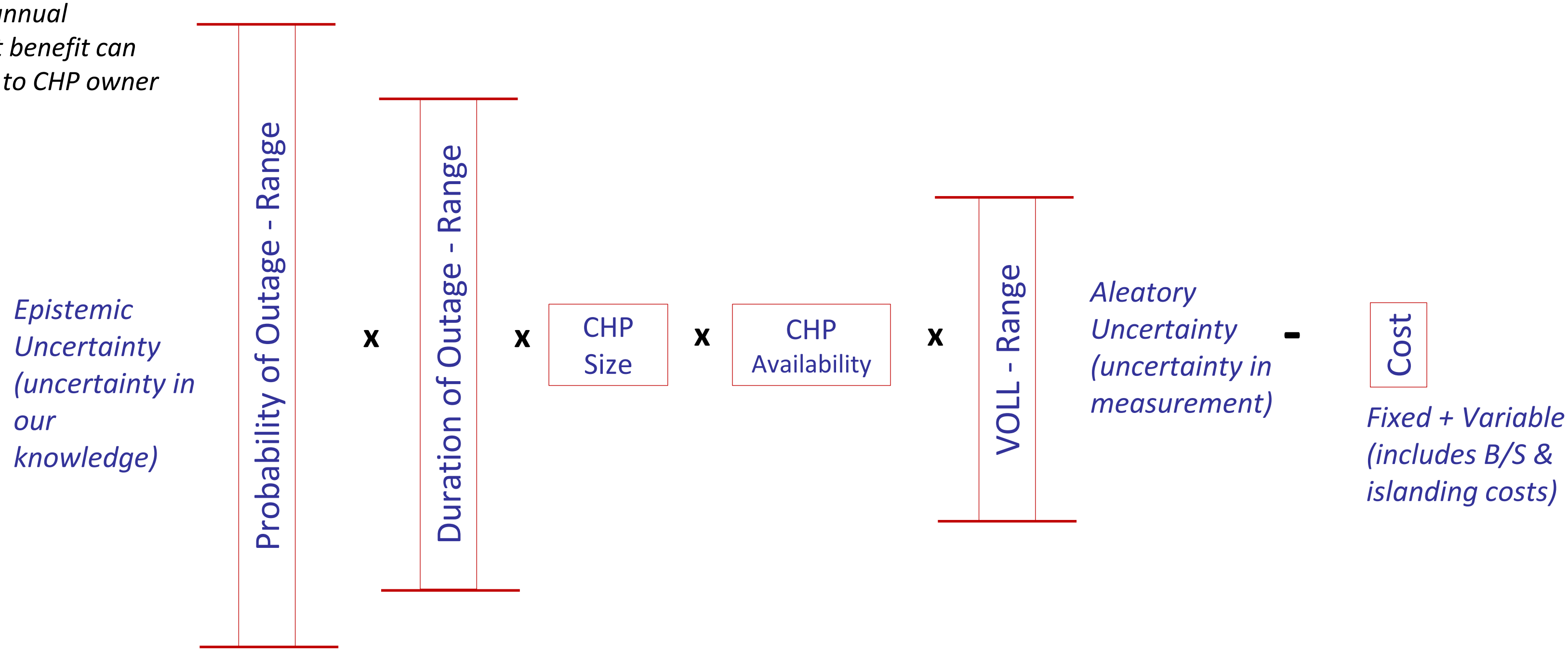
Example and calculations based on – PSE&G Copy of Rate Modeling Criteria Response 2013986 100 kW – submitted to the Standby Working Group

Calculations – Costs to be borne by the CHP Owner	**CHP Outage – Not during PS Monthly System Peak**	**CHP Outage – during PS Monthly System Peak**
Delivery Charges		
Service Charge ($374.49)	374.49	374.49
Annual Demand Charge (3.54 $/kW)	4,253.28	4,253.28
Summer Demand Charge (8.43 $/kW)	-	3,372.84
Distribution Charge (0.001129 $/kWh)	10.84	10.84
Other Charges (including SBC, NGC, STC-TBC, STC-MTC-Tax, Solar Pilot Recovery Charge, RGGI Recovery Charge $/kWh)	278.82	278.82
Supply Charges		
Generation Capacity Obl (8.7703 $/kW)	-	4,392.50
Transmission Capacity Obl (3.9821 $/kW)	-	1,732.22
Ancillary (0.006879 $/kWh)	66.04	66.04
LMP Energy Price (0.0429 $/kWh)	411.84	411.84
Total Cost to the CHP – Total ($)	**5,395.31**	**14,892.86**
Total Cost to the CHP – Total ($/kWh)	**0.56**	**1.55**

Several parameters determine the extent of reliability benefits achieved by B/S & islanding capable CHP (1/6)

Annual Expected Net Benefits of B/S and Islanding Capability **=** Benefits [• *Annual Probability of Outage* **x** • *Duration of Outage (hrs)* **x** • *CHP System Size (MW)* **x** • *VOLL ($/MWh)*] **-** Costs [• *Annual Cost of Black Start & islanding ($/MW)* • *Annual Variable Costs (Fuel + O&M) ($/MWh)*]

NPV of this annual expected net benefit can be allocated to CHP owner and society



4 Probability and duration of outages are difficult to predict (2/6)

Source of information:

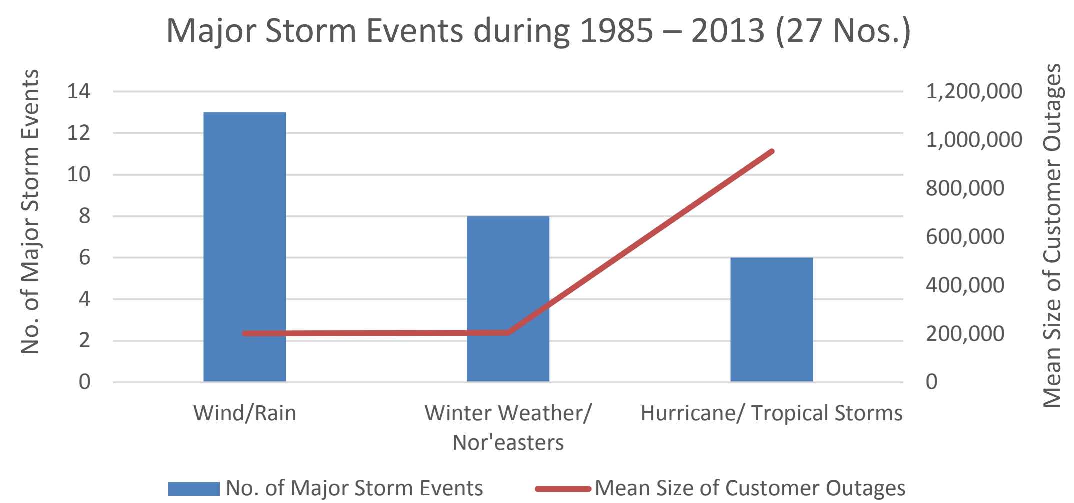
- **NOAA Storm Events Database** used as starting point for fields of data to be collected
- **Bayshore Regional Watershed Council** mainly lists hurricanes and tropical storms to effect NJ

Storm Events Database (1985-2013)

- Sustained outages (lasting > 5 mins)
- Events with >1,000 outages/event
- "Major events" >100,000 outages/ event

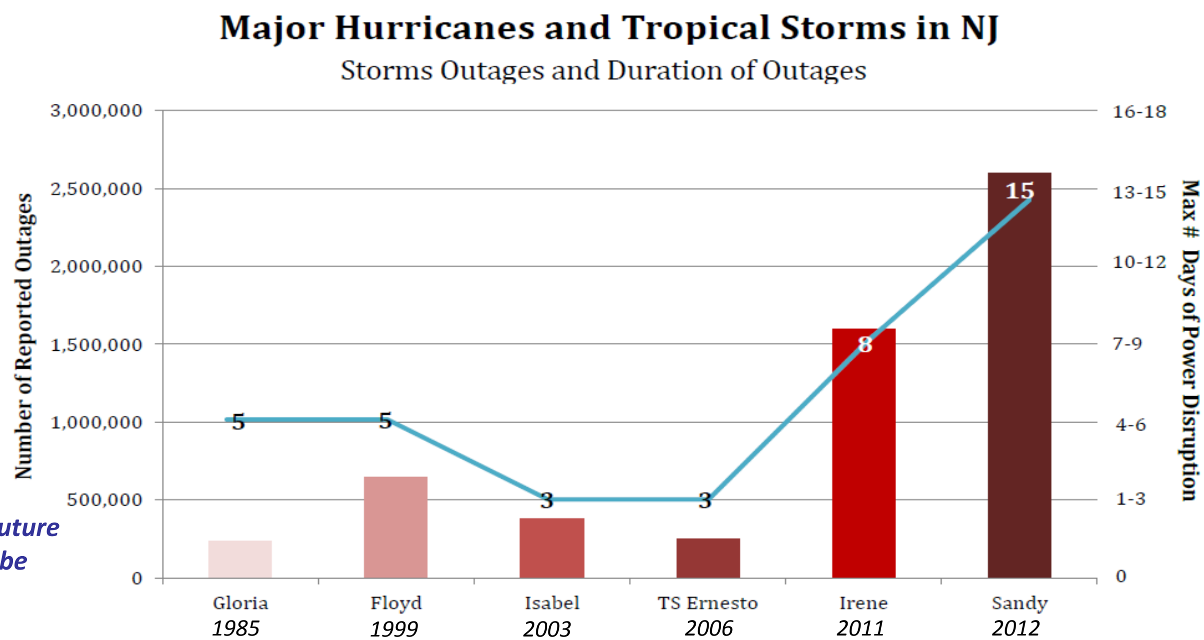
Outages refer to outage for a meter and not for a consumer

Events with >1000 outages per event during 1985-2013	# of Total Events	# of Cumulative Affected Customers	% of reported events	Mean size of customer outages
Wind/Rain	96	4,430,900	67.1	46,155
Winter Weather/Nor'easters	22	2,018,200	15.4	91,736
Ice Storm	5	95,500	3.5	19,100
Tornado	2	121,000	1.4	60,500
Lightning	9	175,800	6.3	19,533
Hurricane/Tropical Storm	9	5,768,500	6.3	640,944
Total	143	12,609,900		



4 Major Hurricanes/ Tropical Storms have occurred at a rate of 0.21 per year in NJ over the last 28 year period (3/6)

- 36 hurricanes and tropical storms have affected New Jersey in various capacities – as remnants of the storm to high levels of precipitation and winds – (since 1985 to 2013), an **average of 1.3 hurricanes or tropical storms per year** over that span of time.
- While some of these 36 hurricanes/tropical storms reported minor electricity distribution impact - including little to no major power loss to customers - our database compilation included 9 total with reported power outages at 1000 or more, and classified **6 as "major" with over 100,000 outages** (many of the 6 exceeding this number) – which means an **average of 0.21 major hurricanes per year**.



Frequency and intensity of future severe weather events may be different than historical

4 VOLL depends upon various factors notably the type of facility (4/6)

Factors affecting VOLL

Location densely populated areas and areas with a high concentration of industry are most affected

Duration longer outages are more disruptive overall, but also have a lower per unit cost

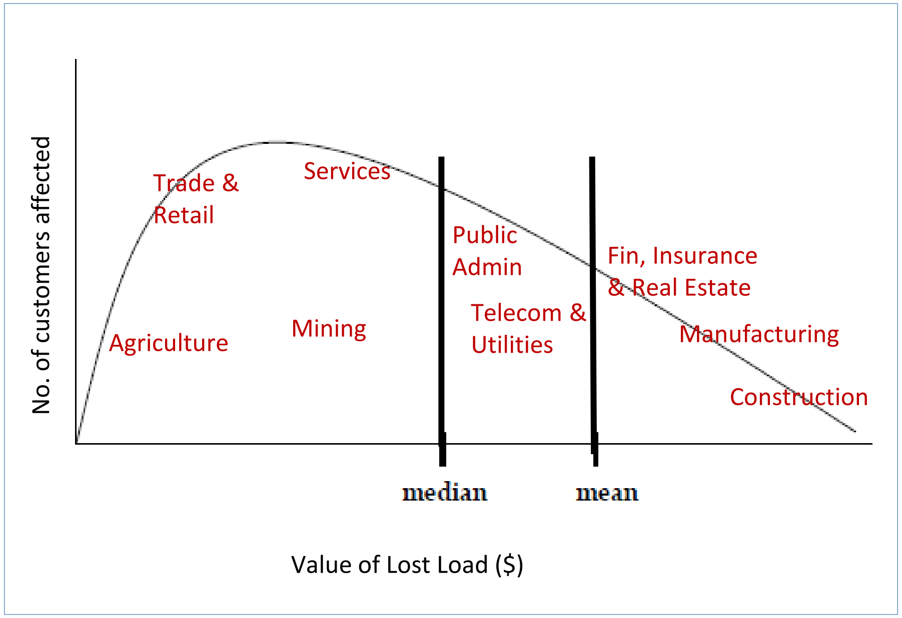
Customer Type residential, commercial or industrial

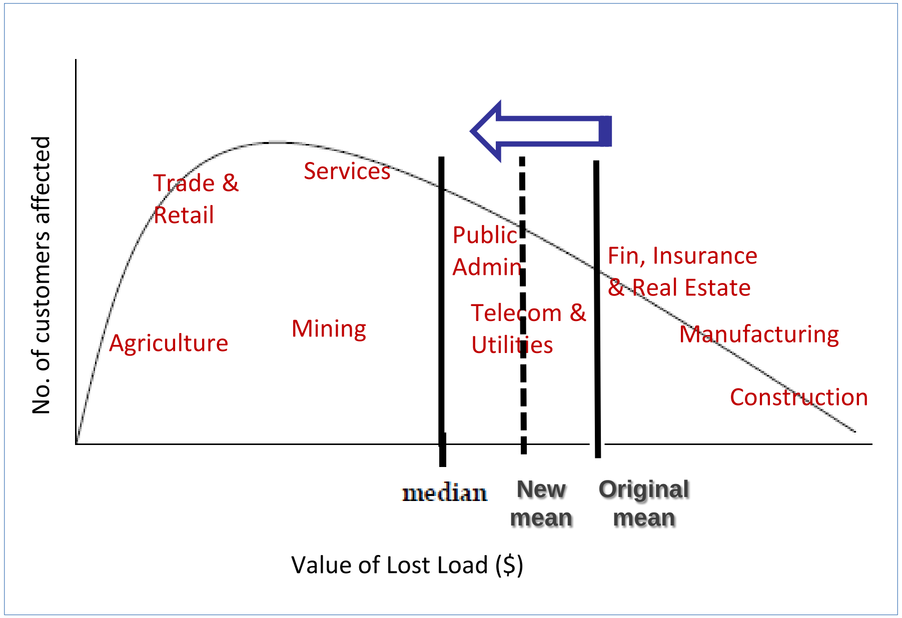
Amount of Notification loss can be lowered by advance notice

Season some industries may face greater loss from outages during certain seasons

Time of Week & Time of Day weekday outages are most costly for firms; for residential weekend outages are more costly; Afternoon interruptions are more costly for firms; morning outages are more costly for residents

VOLL also depends upon whether any existing backup arrangements are present (5/6)





Source:

- *Estimated Value of Service Reliability for Electric Utility Customers in the United States, Lawrence Berkeley National Laboratory, 2009*
- *Estimating the Value of Lost Load, London Economics, 2013*

Possibly customers with high VOLL shall have some back up arrangements; thereby shifting the mean towards left

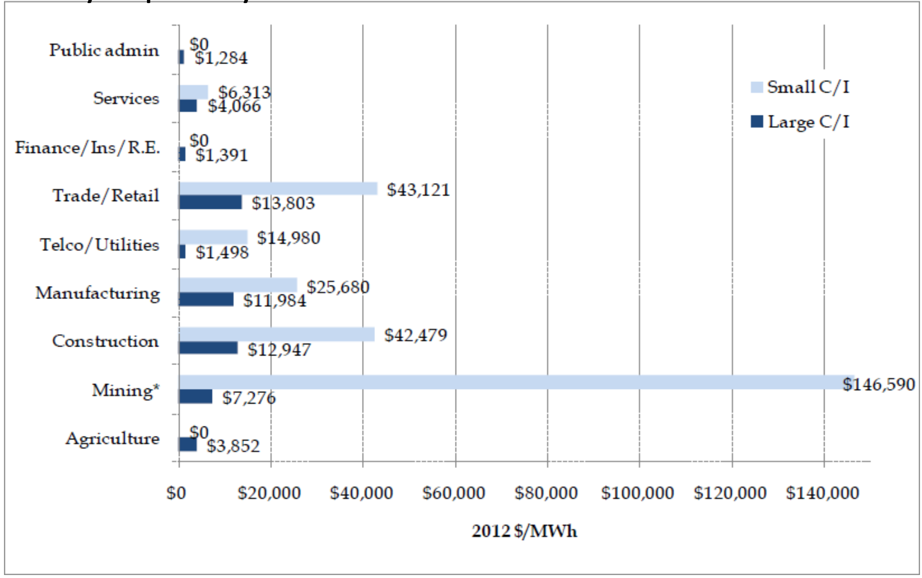
Some estimates of VOLL from previous national and regional studies (6/6)

Costs per Avg. kWhr of a 1 hour interruption for Medium & Large C&I (2008$)	
Interruption Characteristics	**Mean (Ratio)**
__Season__	
Winter	$13.8
Summer	$22.8
__Day__	
Weekend	$30.6
Weekday	$21.4
__Region__	
Midwest	$19.8
Northwest	$19.9
Southeast	$18.2
Southwest	$37.0
West	$28.5

Costs per Avg. kWhr of a 1 hour interruption for Medium & Large C&I (2008$)		**Costs per event – 1 hour interruption duration Medium & Large C&I (Summer Weekday Afternoon) (2008$)**
Interruption Characteristics	**Mean (Ratio)**	
__Industry__		
Agriculture	$43.6	$8,049
Mining	$7.6	$16,366
Construction	$62.9	$46,733
Manufacturing	$22.0	$37,238
Telco. & Utilities	$19.0	$20,015
Trade & Retail	$34.2	$13,025
Fin., Ins. & RE	$32.7	$30,834
Services	$18.7	$14,793
Public Admin	$14.8	$16,601

Source: Estimated Value of Service Reliability for Electric Utility Customers in the United States, Lawrence Berkeley National Laboratory (LBNL), 2009

Estimated VOLLs by sector (median value, $/MWh) – based on the LBNL 2009 study – reported by London Economics



Source: Estimating the Value of Lost Load, London Economics, 2013

Caveats:

- *LBNL does __not__ report median VOLL*
- *LBNL does __not__ report NJ specific or Northeast specific VOLL*
- *London Economics does not study NJ specific or Northeast specific VOLL*
- *London Economics quotes a 2003 Northeast specific study by ICF ("The Economic Cost of the Blackout" which uses an assumed VOLL (as a multiple of retail electricity price) to calculate total economic cost of outage*

Working example of quantifying costs and benefits using the stylized CHP CBA Model (1/3)

CHP Project Level Assumptions	Units	
CHP Technology Type		Gas Turbine
CHP System rated Electric Capacity	kW	1,150
CHP Electric Capacity	kW	1,070
CHP System Availability	%	95%
CHP Hours of Operation	Hrs	8,322
CHP Capacity Factor	%	95%
CHP Economic Life	yrs	20
Project Construction Period	mths	12
CHP Electric Heat Rate	Btu/ kWh	16,047
CHP Thermal Energy Output	MMBtu/ hr	8.31
CHP Capital Cost	$/kW	3,324
CHP O&M Costs	$/kWh	0.01
CHP O&M Cost escalation per year	% per yr	2.20%
CHP Incentive	$/kW	550

Capital Structure, Tax Treatment & Returns		
Equity Usage	%	20%
Cost of Equity	%	16%
Debt Usage	%	80%
Cost of Debt	%	10%
Corporate Tax Rate (Marginal)	%	45%
WACC	%	8%
Federal Investment Tax Credit	%	10%

Electric & Natural Gas Usage - NO CHP		
Facility Annual Peak Demand	kW	2,300
Facility Load Factor	%	60%
Annual Electricity Consumption	MWh/ yr	12,089
Annual Thermal Energy Output from Boiler	MMBtu/ yr	62,240
Boiler Efficiency (No-CHP)	%	80%
Annual Thermal Energy Input (in the Boiler)	MMBtu/ yr	77,800
Electricity Tariff (Commodity + T&D)	$/ kWh	0.13
Natural Gas Tariff (Commodity + T&D)	$/ MMBtu	7.91
Natural Gas Tariff (Commodity + T&D) - to CHP (no SUT charged)	$/ MMBtu	7.39
Electric Tariff escalation (Commodity + T&D)	% per yr	1.98%
NG Tariff escalation (Commodity + T&D)	% per yr	3.20%

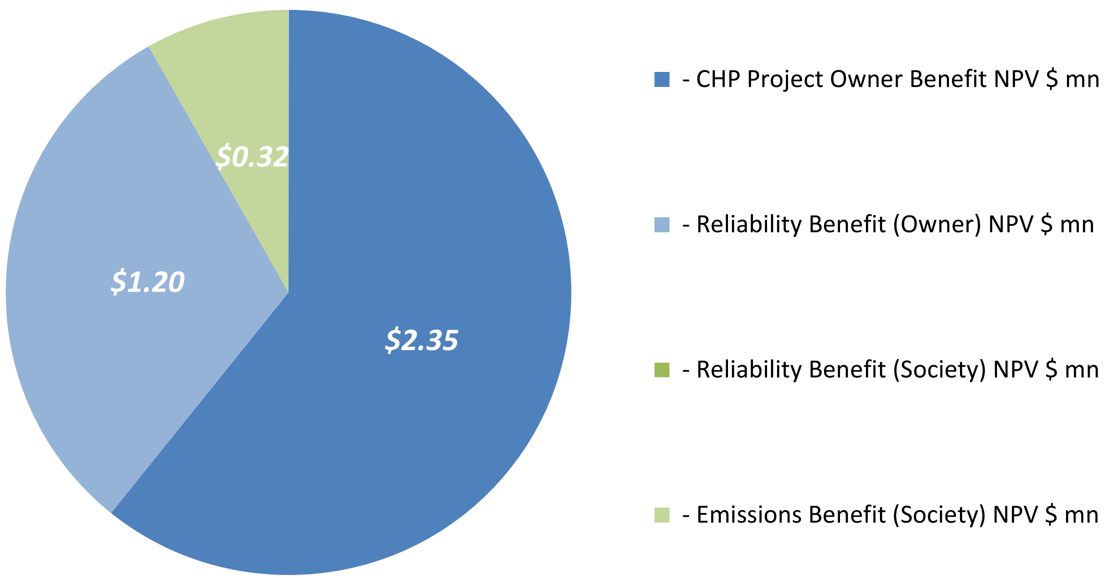
Utility Standby Charges		
Electric Standby Charge (all months)	$/ kW/ mth	3.52
Electric Standby Charge (summer months)	$/ kW/ mth	8.38
CHP Outage (in summer month in a year)	days/ yr	1

Working example of quantifying costs and benefits using the stylized CHP CBA Model (2/3)

Cash Flows

		INSTL.	OPERATING YEAR			
Cash Flows (No-CHP)		*Yr 0*	*Yr 1*	*Yr 2*	*Yr 3*	*Yr n*
Electricity Bill (Commodity + T&D)	$ mn	(1.57)	(1.60)	(1.63)	(1.67)	
Gas Bill (Commodity + T&D)	$ mn	(0.62)	(0.64)	(0.66)	(0.68)	
Total	$ mn	(2.19)	(2.24)	(2.29)	(2.34)	
Cash Flows (CHP)						
Installed Capital Cost without Incentive	$ mn	(3.82)				
CHP Incentive	$ mn	0.59				
Installed Capital Cost with Incentive	$ mn	(3.23)				
Electricity Bill (for purchase from grid) (Commodity + T&D)	$ mn	(1.57)	(0.42)	(0.43)	(0.44)	
Gas Bill (Commodity + T&D)	$ mn	(0.62)	(1.09)	(1.12)	(1.16)	
CHP O&M Expenses	$ mn	0.00	(0.10)	(0.10)	(0.11)	
Electric Standby Charges	$ mn	0.00	(0.11)	(0.11)	(0.11)	
Total	$ mn	(5.42)	(1.72)	(1.77)	(1.82)	
Federal Investment Tax Credit	$ mn	0.32				
Net Savings (due to CHP) to the Owner	$ mn	**(3.23)**	**0.68**	**0.68**	**0.52**	
Reliability Benefits						
Capital Costs	$,000	138.00				
Outage Period	Days	1	1	1	1	
Loss of Load	MWh	25.67	25.67	25.67	25.67	
Value of Loss Load	$,000	128.34	128.34	128.34	128.34	
Net Benefit: Black Start Equip + islanding	$,000	(9.66)	128.34	128.34	128.34	
Emissions Reduction Benefits						
Avoided Electricity Purchase (at Generation level)	MWh	-	9,632	9,632	9,632	
Avoided Electric Emissions – CO_2	Lbs	-	17,878,568	17,878,568	17,878,568	
Avoided Thermal Emissions – CO_2 (Boiler)	Lbs	-	3,550,862	3,550,862	3,550,862	
CHP Emissions – CO_2	Lbs	-	16,706,011	16,706,011	16,706,011	
Net Emissions Benefit – due to CHP (reduced CO_2)	$ mn	-	0.09	0.09	0.10	

Working example of quantifying costs and benefits using the stylized CHP CBA Model (3/3)



Total Societal Benefit	$ mn	**$3.86**	
- CHP Project Owner Benefit NPV	$ mn	**$2.35**	**61%**
- Reliability Benefit (Owner) NPV	$ mn	**$1.20**	**31%**
- Reliability Benefit (Society) NPV	$ mn	**0**	**0%**
- Emissions Benefit (Society) NPV	$ mn	**$0.32**	**8%**

AGENDA

1. Key Inputs into the CHP Cost-Benefit Analysis Model
2. Major Assumptions and Quantifying Uncertainties
3. Response to stakeholder comments received
4. Next Steps

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, 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.

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, they should be counted as costs from the societal perspective, which will essentially reduce the amount of avoided transmission and distribution costs. 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 it assumes that CHP can displace all of marginal coal generation. … Emission rates within the PJM territory 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 run 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: Additional resources – KEMA 2008 Market potential of Combined Heat and Power in Massachusetts and EPRI 2008, Creating Incentives for Electricity Providers to Integrate Distributed Energy Resources	CEEEP is reviewing these studies.

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.

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."	Determining avoided T&D costs is important; CEEEP has not been asked to conduct an avoided T&D cost study.
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

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Expand the CBA model to include other Distributed Energy Resources and Storage

Thank You

Please send your comments/ queries to the below addresses

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