



Rhode Island Distributed
Generation Standard Offer:

*Preliminary Input Assumptions
& Modeling Results for
2013 Ceiling Price Review*

November 7, 2012

Sustainable Energy Advantage, LLC
(with support from Meister Consultants Group)





2013 Ceiling Prices to be established for 9 Classes...

- 4 Solar
- 3 Wind
- 1 Anaerobic Digestion
- 1 Hydro benchmark (*not official CP for 2013*)
- ‘standard’ installations will be modeled to inform setting of ceiling rates for each class

Technology, sub class	Eligible Size Range	Standard Size for Modeling Ceiling Price
Solar, Large	500 kW and above	1.5 MW
Solar, Medium 2	251 – 499 kW	500 kW
Solar, Medium 1	101 – 250 kW	250 kW
Solar, Small	50 – 100 kW	100 kW
Wind, Large	1.0 MW – 1.5 MW	1.5 MW
Wind, Medium	200 kW – 999 kW	750 kW
Wind, Small	90 – 100 kW	100 kW
Anaerobic Digestion	400 – 500 kW	500 kW
Hydroelectric	500 kW – 1.0 MW	1.0 MW



Summary Comparison of 2011/2012 to Proposed 2013 Ceiling Prices

Technology, sub-class	2011/2012 Ceiling Price (¢/kWh)	2013 Proposed Ceiling Price (¢/kWh) <u>w/PTC</u>	Net Change* btw previous and proposed Ceiling Prices	2013 Proposed Ceiling Price (¢/kWh) <u>w/o PTC</u>
Solar, 500 kW+	28.95	24.95	-14%	N/A
Solar, 251 – 499 kW	31.60	28.40	-10%	N/A
Solar, 101 – 250 kW	33.35 (for 150 kW)	28.80	-14%	N/A
Solar, 50 – 100 kW	33.35 (for 150 kW)	29.95	-10%	N/A
Wind, 1 – 1.5 MW	13.35	16.80	+26%	18.60
Wind, 400 – 999 kW	N/A	18.15	N/A	19.95
Wind, 90 – 100 kW	N/A	24.65	N/A	N/A
AD, 400 – 500 kW	N/A	18.55	N/A	19.55
Hydro, 500 kW – 1 MW	N/A	17.90	N/A	18.85

* See next slide



Comparison of 2011/2012 to Proposed 2013 Ceiling Prices, Cont.

- A reduction in the market-based total installed cost of solar PV was the principle driver of the proposed reduction in Standard Offer prices for solar.
- The availability of actual cost data for 1.5 MW wind turbine generators installed in southeastern MA was the principle driver of the proposed increase in the Standard Offer price for 1.5 MW Wind.
- 2 additional factors played an important role in the analytical review of proposed 2013 CPs:
 1. The availability of **bonus depreciation** (100% in 2011, and 50% in 2012) is **scheduled to cease** for projects coming on-line beginning 1/1/2013. All else equal, the removal of 50% bonus depreciation would cause an increase in the cost of energy – estimated at 7% for 1.5 MW solar and 8% for 1.5 MW wind.
 2. The **expiration of the 1603 cash payment** in lieu of the ITC significantly reduces most investors' ability to fully monetize the Investment Tax Credit. This analysis estimates 90% ITC monetization. All else equal, reducing the ITC benefit by 10% would cause an increase in the cost of energy – estimated at 4% for 1.5 MW solar. For wind, reduced monetization plus the expiration of the ability to use the ITC (or 1603 payment) in lieu of the PTC could cause an increase in the cost of energy of up to 25%.

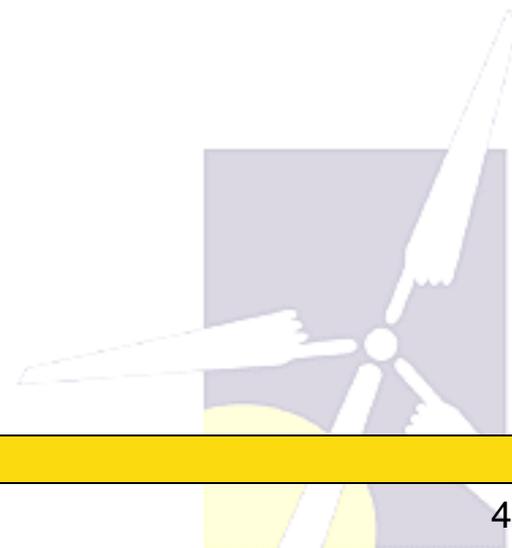
As a result, proposed CPs demonstrate a *net* reduction ranging between 10% and 14% for solar, and a *net* increase for wind of approximately 26%.

Est. Impact of Changes in Federal Incentives on LCOE

	Solar, 1.5 MW		Wind, 1.5 MW	
	Impact of Fed. Inc.	Net Change	Impact of Fed. Inc.	Net Change
Sunset of (50%) Bonus Depreciation	+ 7%	- 14%	+8%	+ 26%
90% monetization; + Switch from ITC to PTC for Wind	+ 4%		+ 2%	



SOLAR





Est. of 15-year levelized contract: Solar

In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)			
	50-100 kW	101-250 kW	251-499 kW	500 kW and above
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	29.65	28.55	28.15	24.75
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	30.25	29.05	28.65	25.15
Average = Proposed Ceiling Price	29.95	28.80	28.40	24.95
2011 Ceiling Prices	33.35 (150 kW)	33.35 (150 kW)	31.60	28.95



Researched cost, O&M & financing inputs: Solar \approx 100 kW dc (1)

Input category*

Expected Annual Average Net capacity factor, (%) DC

Proposed Input = 14.39%

(rationale: 7 of 8 respondents had no comments on what was in 2011)

2011 Input = 14.39%

Annual Production Degradation (%)

Proposed Input = 0.5%

2011 Input = 0.5%

Total installed cost ($\$/kW_{DC}$), excluding Interconnection Cost

Proposed Input = \$3,100 -> \$3,150/kW

2011 Input = \$3,900

+ \$70/kW 20-yr inverter warranty

Interconnection cost (\$)

Proposed Input = \$50/kW

2011 Input = \$210/kW

O&M expenses (in $\$/kW_{DC}$ -year) in Year 1 of operations

Proposed Input = \$20/kW-yr

2011 Input = \$22/kW-yr



Researched cost, O&M & financing inputs: Solar \approx 100 kW dc (2)

Input category*

Insurance, Yr 1, (% of total project costs or \$/yr)

Proposed Input = 0.3% of total proj. costs

2011 Input = 0.3%

Project Management, Yr 1 (\$/yr)

Proposed Input = \$1,400/yr

2011 Input= included in overall O&M

Land Lease, Yr 1 (\$/yr)

Proposed Input = \$2,500/yr

2011 Input = \$1,500 for 150 kW project

Annual average escalation rate for O&M expenses (%)

Proposed Input = 3%

2011 Input = 3%

Royalties (% of Revenue, or \$/yr)

Proposed Input = 0.0% (covered in lease)

2011 Input = 0.0%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

2011 Input = \$5,250 for 150 kW project,

annual adjustment factor = -10.0%



*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.



Researched cost, O&M & financing inputs: Solar \approx 100 kW dc (3)

Input category*

Length of construction period (months)

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Source (D/E) and Cost (e.g. interest rate) of construction financing

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Debt-to-equity ratio

Proposed Input = same (result = 48%)

2011 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 14 -> 13 yrs; 2011 Input = 12 years

Interest rate on debt (%)

Proposed Input = 6.5%; 2011 Input = 6.5%

Lender's Fee (% of loan amt)

Proposed Input = same; 2011 Input = included in cap. cost

Avg. Debt Service Coverage Ratio

Proposed Input = 1.40; 2011 Input = 1.45

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 12%; 2011 Input = 13%

Decommissioning Reserve?

Proposed Input = same; 2011 Input = \$0 (= salvage value)

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.



Researched cost, O&M & financing inputs: Solar \approx 250 kW dc (1)

Input category*

Expected Annual Average Net capacity factor, (%) DC

Proposed Input = 14.39%

(rationale: 7 of 8 respondents had no comments on what was in 2011)

2011 Input = 14.39%

Annual Production Degradation (%)

Proposed Input = 0.5%

2011 Input = 0.5%

Total installed cost (\$/kW_{DC}), excluding Interconnection Cost

Proposed Input = \$2,750 -> \$2650/kW

2011 Input = \$3,900

(excl. Interconnection costs)

+ \$70/kW 20-yr inverter warranty

Interconnection cost (\$)

Proposed Input = \$40/kW

2011 Input = \$210/kW

O&M expenses (in \$/kW_{DC}-year) in Year 1 of operations

Proposed Input = \$20/kW-yr

2011 Input = \$22.00/kW



Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (2)

Input category*

Insurance, Yr 1, (% of total project costs or \$/yr)

Proposed Input = 0.3% of total proj. costs

2011 Input = 0.3%

Project Management, Yr 1 (\$/yr)

Proposed Input = \$3,500/yr

2011 Input= included in overall O&M

Land Lease, Yr 1 (\$/yr)

Proposed Input = \$10,000/yr

2011 Input = \$1,500/yr for 150 kW project

Annual average escalation rate for O&M expenses (%)

Proposed Input = 3%

2011 Input = 3%

Royalties (% of Revenue, or \$/yr)

Proposed Input = 0.0% (covered in lease)

2011 Input = 0.0%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

2011 Input = \$5,250 for 150 kW project, annual adjustment factor = -10.0%

Length of construction period (months)

Proposed Input = included in installed costs;

2011 Input = included in installed costs



Researched cost, O&M & financing inputs: Solar \approx 250 kW dc (3)

Input category*

Source (D/E) and Cost (e.g. interest rate) of construc. financing

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Debt-to-equity ratio

Proposed Input = same (result = 48.75%)

2011 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 14 -> 13 yrs; 2011 Input = 12 years

Interest rate on debt (%)

Proposed Input = 6.5%; 2011 Input = 6.5%

Lender's Fee (% of loan amt)

Proposed Input = same; 2011 Input = included in cap. cost

Avg. Debt Service Coverage Ratio

Proposed Input = 1.35; 2011 Input = 1.45

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 11.5%; 2011 Input = 13%

Decommissioning Reserve?

Proposed Input = same; 2011 Input = \$0 (= salvage value)



Researched cost, O&M and financing inputs: Solar \approx 450 kW dc (1)

Input category

Expected Annual Avg. Net c.f. (%)

Proposed Input = 14.56%

(rationale: 7 of 8 respondents had no comments)

2011 Input = 14.56%

Annual Production Degradation (%)

Proposed Input = .5%

2011 Input = 0.5%

Total installed cost ($\$/\text{kW}_{\text{DC}}$), excluding Interconnection Cost

Proposed Input = \$2,500 -> \$2,650/kW

2011 Input = \$3,700

(excl. Interconnection costs)

+\$60/kW 20-yr inverter warranty

Interconnection cost (\$)

Proposed Input = \$300/kW

2011 Input = \$185/kW

O&M expenses (in $\$/\text{kW}_{\text{DC}}\text{-year}$) in Year 1 of operations

Proposed Input = \$20/kW-yr

2011 Input = \$22/kW

Insurance, Yr 1, (% of total project costs or $\$/\text{yr}$)

Proposed Input = 0.3% of total proj. costs

2011 Input = 0.3%



Researched cost, O&M and financing inputs: Solar \approx 450 kW dc (2)

Input category

Project Management, Yr 1 (\$/yr)

Proposed Input = \$6,500/yr

2011 Input= included in overall O&M

Land Lease, Yr 1 (\$/yr)

Proposed Input = \$15,000

2011 Input = \$7,500

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 3%

2011 Input = 3%

Royalties (% of Revenue, or \$/yr)

Proposed Input = 0.0% (covered in lease)

2011 Input = 0%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

2011 Input = \$17,500 annual adjustment factor = -10.0%



Researched cost, O&M and financing inputs: Solar \approx 450 kW dc (3)

Input category

Length of construction period (months)

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Source (D/E) and Cost (e.g. int. rate) of constr. financing

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Debt-to-equity ratio

Proposed Input = same (result = 51.5%)

2011 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 14 -> 13 yrs

2011 Input = 12 years

Interest rate on debt (%)

Proposed Input = 6.0%

2011 Input = 6.5%



Researched cost, O&M and financing inputs: Solar \approx 1,500 kW dc (1)

Input category

Expected Annual Avg. Net capacity factor, (%)

Proposed Input = 14.65%

(rationale: 7 of 8 respondents had no comments)

2011 Input = 14.65%

Annual Production Degradation (%)

Proposed Input = .5%

2011 Input = 0.5%

Total installed cost ($\$/\text{kW}_{\text{DC}}$), excluding Interconnection Cost

Proposed Input = \$2,400 -> \$2,550/kW

2011 Input = \$3,400 (excl. Interconnection costs) + \$50/kW 20-yr inverter warranty

Interconnection cost (\$)

Proposed Input = \$150/kW

2011 Input = \$132/kW

O&M expenses (in $\$/\text{kW}_{\text{DC}}\text{-year}$) in Year 1 of operations

Proposed Input = \$15/kW-yr

2011 Input = \$24/kW

Insurance, Yr 1, (% of total project costs or $\$/\text{yr}$)

Proposed Input = 0.25%

2011 Input = 0.2%



Researched cost, O&M and financing inputs: Solar \approx 1,500 kW dc (2)

Input category

Project Management, Yr 1 (\$/yr)

Proposed Input = \$10,000

2011 Input= included in overall O&M

Land Lease, Yr 1 (\$/yr)

Proposed Input = \$30,000 -> \$34,500 to reflect tax on underlying land

2011 Input = \$33,000

Annual average escalation rate for O&M expenses (%)

Proposed Input = 3%

2011 Input = 2.5%

Royalties (% of Revenue, or \$/yr)

Proposed Input = 0.0% (covered in lease)

2011 Input = 0.0%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

2011 Input = \$52,500, annual adjustment: -10%

Length of construction period (months)

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Source (D/E) and Cost (e.g. interest rate) of construction financing

Proposed Input = included in installed costs;

2011 Input = included in installed costs



Researched cost, O&M and financing inputs: Solar \approx 1,500 kW dc (3)

Input category

Debt-to-equity ratio

Proposed Input = same (result = 51.25%)

2011 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 14 -> 13 yrs

2011 Input = 12 yrs

Interest rate on debt (%)

Proposed Input = 5.5%

2011 Input = 6%

Lender's Fee (% of loan amt)

Proposed Input = same;

2011 Input = included in cap. cost

Avg. Debt Service Coverage Ratio

Proposed Input = 1.35

2011 Input = 1.45

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 12%

2011 Input = 13%

Decommissioning Reserve?

Proposed Input = \$200,000

2011 Input = \$0 (= salvage value)



Incentives

- Federal Investment Tax Credit (ITC) assumed available at time of initial operation (2013/2014)
 - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed



Additional Assumptions

- COD achieved in 2013
- Project Useful Life: 25 years
- 0.5%/yr production degradation
- Debt Service Coverage Ratio:
 - Min = 1.20X
 - Avg. varies by case
- Interconn. Costs depreciated on 15-year MACRS schedule
- All other project costs:
 - 96% depreciated on 5-year MACRS
 - 2% depreciated on 15-year MACRS
 - 2% not depreciable
- Fed. Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- *Assumed NEPOOL Membership costs either covered by NGRID as lead participant, or spread over many installations and therefore negligible*
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of **solar-weighted** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (next slide)



Additional Assumptions: Forecast of Market Value of Production

<u>Project Year</u>	<u>Calendar Year</u>	<u>Time-of-Production Weighted Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)</u>
16	2029	10.04
17	2030	10.24
18	2031	10.43
19	2032	10.63
20	2033	10.84
21	2034	11.05
22	2035	11.26
23	2036	11.47
24	2037	11.70
25	2038	11.92



Benchmarking to CT ZREC Program

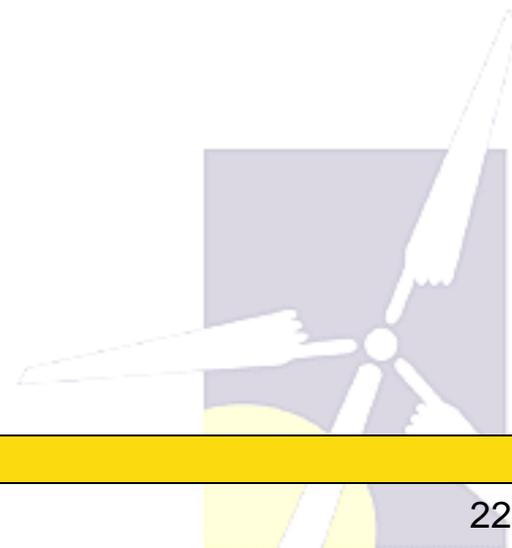
October 2012 Results

Large ZREC: 250kW – 1 MW Medium ZREC: >100 kW <250 kW Small ZREC: ≤ 100 kW <i>(All Behind the Meter)</i>	UI Large ZREC (\$/REC)	CL&P Large ZREC (\$/REC)	UI Medium ZREC (\$/REC)	CL&P Medium ZREC (\$/REC)
Weighted <u>Average</u> Bid Price of Accepted Bids	\$117.27	\$101.36	\$135.36	\$149.29
	6 accepted bids: All but 1 winner <500 kW	Winners span whole size range.	Winners range from 132 – 250 kW	Winners range from 101 – 250 kW
Approx. Value of Retail Electricity Purchases Avoided, <i>Levelized</i>*	\$166-191		\$166-191	
Est. Value Under 3rd-Party Net Metering (Assumed 10-15% discount, common in MA)	\$113-138		\$113-138	
Est. Equivalent to Calculated LCOE	\$258-289		\$276-307	

* *Levelization assumes 4% annual rate escalation and 10% discount rate.*



WIND





Est. of 15-year levelized contract: Wind

In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)				
	1.5 MW		750 kW		100 kW
	w/PTC	w/o PTC	w/PTC	w/o PTC	
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	16.65	18.45	17.95	19.85	24.35
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	16.95	18.75	18.35	20.05	24.95
Average = Proposed Ceiling Price	16.80	18.60	18.15	19.95	24.65
<i>2011 Ceiling Price</i>	<i>13.35</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>



Researched cost, O&M and financing inputs: Wind 1,500 kW (1)

Input category

Expected Annual Average Net capacity factor, (%)

Proposed Input = 27.5% *(to account for new turbine optimization to low wind regimes)*

2011 Input = 25%

Annual Production Degradation

Proposed Input = 0.5%

2011 Input = 0.5%

Total installed cost (\$/kW), **excluding** Interconnection Cost

Proposed Input = \$3,200/kW

2011 Input = \$2,750/kW (excl. interconnection costs)

Typical Interconnection cost (\$/kW)

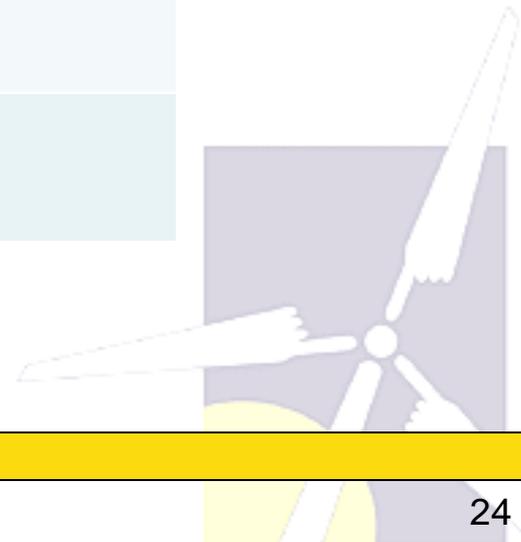
Proposed Input = \$100/kW

2011 Input = \$117/kW

O&M expenses in Year 1 of operations

Proposed Input = \$30/kW-yr

2011 Input = \$55/kW-year





Researched cost, O&M and financing inputs: Wind 1,500 kW (2)

Input category

Insurance Expense (as % of total proj. cost, or in \$/yr)

Proposed Input = 0.3% of total project cost

2011 Input = included in O&M

Project Management

Proposed Input = \$15,000/yr

2011 Input = included in O&M

Land Lease, Year 1 (\$/year)

Proposed Input = \$20,000/yr

2011 Input = included in O&M

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 2.5%

2011 Input = 2%

Royalties

Proposed Input = included in lease exp.

2011 Input = included in O&M

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

Length of construction period (months)

Proposed Input = included in installed costs;

2011 Input = included in installed costs



Researched cost, O&M and financing inputs: Wind 1,500 kW (3)

Input category

Source and Cost of Construction Financing

Proposed Input = included in installed costs;

2011 Input = included in installed costs

Debt-to-equity ratio

Proposed Input = same (56.25%)

2011 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 15 yrs

2011 Input = 12 Yrs.

Interest rate on debt (%)

Proposed Input = 5.5%

2011 Input = 6.5%

Lender's Fee

Proposed Input = same;

2011 Input = included in cap. cost

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 11% -> 12%

2011 Input = 13%

Decommissioning Reserve

Proposed Input = \$0 (= salvage value)

2011 Input = \$0 (= salvage value)



Researched cost, O&M and financing inputs: Wind 750 kW (1)

Input category

Expected Annual Average Net capacity factor, (%)

Proposed Input = 24%

Annual Production Degradation

Proposed Input = 0.5%

Total installed cost (\$/kW), **excluding** Interconnection Cost

Proposed Input = \$2,800

Typical Interconnection cost (\$/kW)

Proposed Input = \$137/kW

O&M expenses (in ¢/kWh) in Year 1 of operations

Proposed Input = \$30/kW-yr

Insurance Expense (as % of total project cost, or in \$/yr)

Proposed Input = 0.3% of total proj. costs

Project Management

Proposed Input = \$15,000

Land Lease, Year 1 (\$/year)

Proposed Input = \$10,000

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 2.5%



Researched cost, O&M and financing inputs: Wind 750 kW (2)

Input category

Royalties

Proposed Input = included in lease exp.

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

Length of construction period (months)

Proposed Input = included in installed costs;

Source and Cost of Construction Financing

Proposed Input = included in installed costs;

Debt-to-equity ratio

Proposed Input = debt optimized to cash flow (result = 66%)

Debt tenor (years)

Proposed Input = 15 yrs

Interest rate on debt (%)

Proposed Input = 6%

Lender's Fee

Proposed Input = included in cap. cost

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 12%

Decommissioning Reserve

Proposed Input = \$0 (salvage value)



Researched cost, O&M and financing inputs: Wind 100kW (1)

Input category

Expected Annual Average Net capacity factor, (%)

Proposed Input = 23%

Annual Production Degradation

Proposed Input = 0.5%

Total installed cost (\$/kW), **excluding** Interconnection Cost

Proposed Input = \$5,600/kW

Typical Interconnection cost (\$/kW)

Proposed Input = \$200/kW

O&M expenses (in \$/kW-year) in Year 1 of operations

Proposed Input = \$20/kW-yr

Insurance Expense (as % of total project cost, or in \$/yr)

Proposed Input = 0.3% of total proj. costs

Project Management

Proposed Input = \$2,000

Land Lease, Year 1 (\$/year)

Proposed Input = \$2000/year

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 2.5%

Royalties

Proposed Input = included in lease exp.



Researched cost, O&M and financing inputs: Wind 100kW (2)

Input category

Property Taxes

Proposed Input = assumed exempt

Length of construction period (months)

Proposed Input = included in installed costs;

Source and Cost of Construction Financing

Proposed Input = included in installed costs;

Debt-to-equity ratio

Proposed Input = debt optimized to cash flow (result = 50.25%)

Debt tenor (years)

Proposed Input = 15 yrs

Interest rate on debt (%)

Proposed Input = 6%

Lender's Fee

Proposed Input = included in cap. cost

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 12%

Decommissioning Reserve

Proposed Input = \$0 (salvage value)



Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
 - For 750 kW and 1500 kW wind, ceiling prices calculated both with and without PTC extension.
 - For these categories, monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
 - For 100 kW wind, assume ITC available and fully monetized through 2016.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed



Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.35X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
 - 96% depreciated on 5-year MACRS
 - 2% depreciated on 15-year MACRS
 - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of **wind-weighted** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (see next slide)

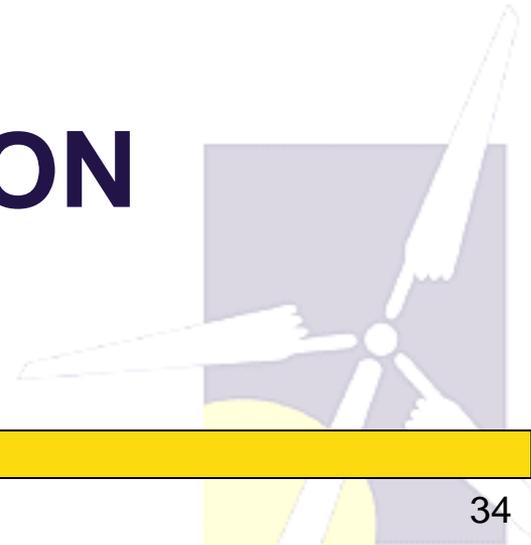


Additional Assumptions: Forecast of Market Value of Production

Project Year	Calendar Year	Time-of-Production Weighted Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	9.63
17	2030	9.82
18	2031	10.01
19	2032	10.20
20	2033	10.39



ANAEROBIC DIGESTION





Est. of 15-year levelized contract: Anaerobic Digestion

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)	
	500 kW	
	w/PTC	w/o PTC
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	18.35	19.35
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	18.75	19.75
Average = Proposed Ceiling Price	18.55	19.55



Anaerobic Digestion - Overview

- The most common opportunity for AD in RI is *assumed* to be for food waste digesters. Sludge or manure-based applications are also possible.
- Feed stocks are expected to be derived from food manufacturing, restaurant and grocery waste. *No manure or WWTP sludge are assumed – although such projects may be possible in RI.*
- *The VT Standard Offer program established a farm digester price which esc. from 13.6 to 15.0 cents/kWh over a 20 year contract. The VT Standard Offer contract allows the generator to keep and sell all RECs – and retain associated revenue.*
- This approach means that there are *no fuel costs*. Fuel deliveries will generate a *tipping fee*, and are assumed to arrive clean, with no cost to dispose of packaging.
- ~~Further, it is assumed that digestate will be sold, generating additional revenue for the facility.~~



Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (1)

Input category

Biogas consumption/day (ft³/day)

Proposed Input = 150,000

Energy content/cubic foot (BTU/cubic ft)

Proposed Input = 650 BTU/cubic ft

Heat Rate (BTU/kWh)

Proposed Input = 9,000 BTU/kWh

Availability Factor

Proposed Input = 92%

Station Service/Parasitic Load

Proposed Input = 10%

Annual Production Degradation (%)

Proposed Input = 0%

Total installed cost (\$/kW), excl. Interconnection Cost

Proposed Input = \$9,500 -> \$10,000/kW -- additional \$500/kW takes into account ownership of land

Typical Interconnection cost (\$)

Proposed Input = \$150,000



Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (2)

Input category

O&M expenses (\$/kW-yr), Yr 1 (excluding those listed below)

Proposed Input = \$300/kW-yr

Variable O&M (¢/kWh), Yr 1 (excluding those listed below)

Proposed Input = 2¢/kWh

Insurance, Yr 1, (provide as % of total project cost, or in \$/yr)

Proposed Input = 0.4%

Project Management, Yr 1 (\$/yr)

Proposed Input = \$30,000/yr

Land Lease, Yr 1 (\$/yr)

Proposed Input = \$5,000 -> \$0/yr (land assumed purchased by the project @ equivalent of \$500/kW)

Annual average escalation rate for O&M expenses (%)

Proposed Input = 2 %

Royalties (% of revenue, or \$/yr)

Proposed Input = 0%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%



Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (3)

Input category

Length of construction period (months)

Proposed Input = included in installed costs;

Source and Cost of Construction Financing

Proposed Input = included in installed costs;

Debt-to-equity ratio

Proposed Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 13 years

Interest rate on debt (%)

Proposed Input = 7 %

Lender's Fee

Proposed Input = included in cap. cost

Avg. Debt Service Coverage Ratio

Proposed Input = 1.5

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 12 %

Decommissioning Reserve

Proposed Input = \$0

Tipping Fees/Digestate Revenue, If Applicable: \$/ton, and tons per year

Proposed Input = Tipping Fee: \$10 -> \$30/ton ; Digestate: 7¢ -> 0¢/gal.



Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
 - Anaerobic digesters eligible for 50% of face value
 - Ceiling prices calculated both with and without PTC extension.
 - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed



Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.50X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
 - 96% depreciated on 5-year MACRS
 - 2% depreciated on 15-year MACRS
 - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (see next slide)

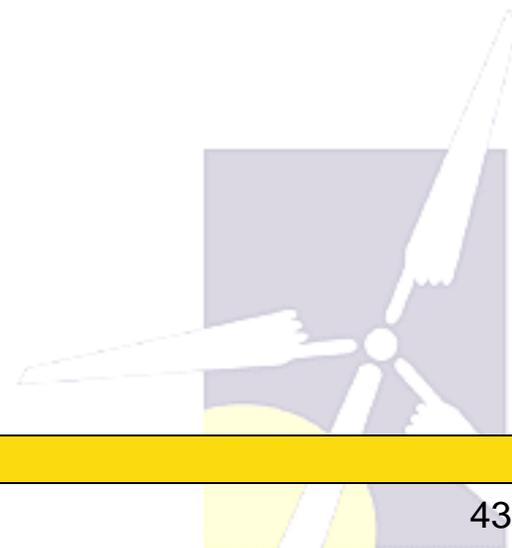


Additional Assumptions: Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	9.70
17	2030	9.89
18	2031	10.08
19	2032	10.27
20	2033	10.46



HYDRO





Est. of 15-year levelized contract: Hydro

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)	
	1,000 kW	
	w/PTC	w/o PTC
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	17.75	18.75
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	18.05	18.95
Average = Proposed Ceiling Price	17.90	18.85



Researched cost, O&M and financing inputs: Hydro 500-1000kW

Input category

Expected Annual Average Net capacity factor, (%)

Proposed Input = 40%

Total installed cost (\$/kW), **excluding** Interconnection Cost

Proposed Input = \$4,000/kW (excl. interconnection costs)

Typical Interconnection cost (\$/kW)

Proposed Input = \$100/kW

O&M expenses (in \$/kW-year) in Year 1 of operations

Proposed Input = \$13/kW-year

Variable O&M (¢/kWh), Yr 1 (excluding those listed below)

Proposed Input = 2.00 ¢/kWh

Insurance Expense (as % of total project cost, or in \$/yr)

Proposed Input = 0.5%

Project Management

Proposed Input = \$30,000/year



Researched cost, O&M and financing inputs: Hydro 500-1000kW

Input category

Land Lease, Year 1 (\$/year)

Proposed Input = (see royalties)

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 2.5%

Royalties

Proposed Input = 3.5%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%

Length of construction period (months)

Proposed Input = included in installed costs

Source and Cost of Construction Financing

Proposed Input = included in installed costs

Debt-to-equity ratio

Proposed Input = debt optimized to cash flow



Researched cost, O&M and financing inputs: Hydro 500-1000kW

Input category

Debt tenor (years)

Proposed Input = 14 Yrs.

Interest rate on debt (%)

Proposed Input = 6.75%

Lender's Fee

Proposed Input = included in cap. cost

Avg. Debt Service Coverage Ratio

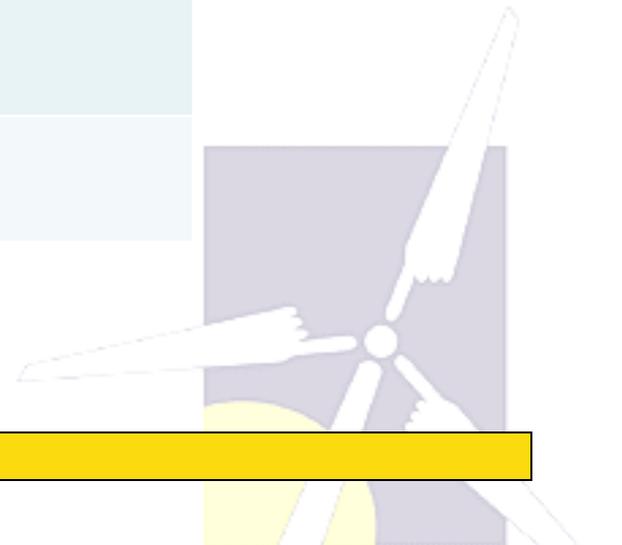
Proposed Input = 1.45

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 12%

Decommissioning Reserve

Proposed Input = \$0





Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
 - Hydro is eligible for 50% of face value
 - Ceiling prices calculated both with and without PTC extension.
 - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed



Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 30 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.45X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
 - 96% depreciated on 5-year MACRS
 - 2% depreciated on 15-year MACRS
 - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 75% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (see next slide)



Additional Assumptions: Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	9.70
17	2030	9.89
18	2031	10.08
19	2032	10.27
20	2033	10.46
21	2034	10.66
22	2035	10.87
23	2036	11.08
24	2037	11.29
25	2038	11.51
26	2039	11.73
27	2040	11.95
28	2041	12.18
29	2042	12.37
30	2043	12.56



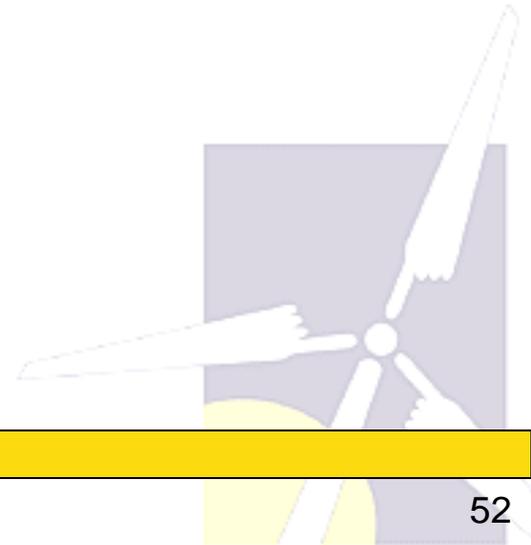
Sustainable Energy Advantage, LLC

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APPENDIX A - SOLAR





Capital Cost, Installed: Details, Sources

(Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder Data Request
 - Responses received from stakeholders: solar (12), wind (9), anaerobic digestion (5) and hydro (5)
- Follow up Interviews; Data available to SEA through other recent engagements
- Industry Databases Polled

Usable data extracted from:

- MA SREC Database [installed cost data analyzed from projects installed within the last 3, 6, and 9 months]
- NREL July 2012 distributed generation cost estimates

Database reviewed; data of limited direct usefulness, from:

- NYSERDA PowerClerks Database (Only systems <100 kW; access to raw data not available)
- California Solar Initiative Database (Data concerns, inconsistency with more relevant databases)
- Mass CEC Commonwealth Solar Database (Not updated since 3/12; likely redundant with SREC Database)
- Delaware SREC Long-term Contract Auction Results (No installed cost data available, only auction results)
- New Jersey EDC Long-term Contract Auction Results (No installed cost data available, only auction results, last auction was in 2011)

Costs embedded in total installed cost estimates include:

Soft Costs: *development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

Inverter warranty: *The solar CREST model has the ability to incorporate two capital expenditures during operations, which could be used to model inverter replacements. In response to recent data and stakeholder feedback, however, this analysis assumes that a 20-year inverter warranty is included in the total installed cost estimate. No additional inverter replacement costs are modeled.*



Mass SREC Database

(Sept 2011-August 2012)

Mass SREC Database - Average Installed Cost by Bin Quarter (\$/Watt)

Size Bin (kW)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
50-100	\$5.97	\$5.59	\$4.75	\$4.85
101-250	\$5.14	\$5.48	\$4.76	\$4.33
251-500	\$4.75	\$4.78	\$3.98	\$4.00
500+	\$3.82	\$5.25	\$4.11	\$4.10

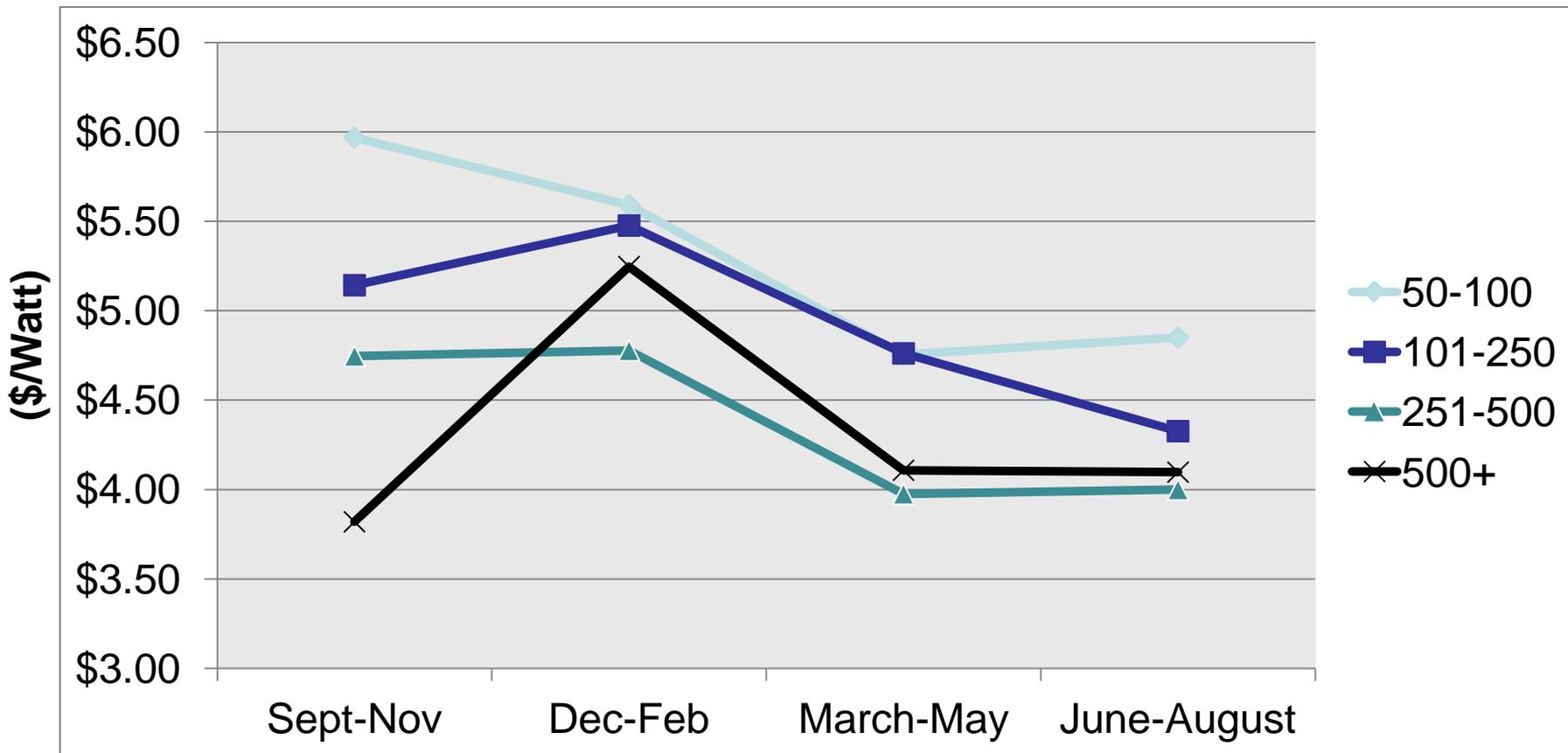
Mass SREC Database - Average Installed Cost for Target Sizes by Quarter (\$/Watt)

Size Bin (kW)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
350-650	\$5.05	\$4.88	\$4.35	\$3.84
1000-2500		\$5.75	\$4.33	\$3.98

Note: MA SREC data are backward looking, and generally represent the downward trending market. Where comparable, 2013 costs are expected to be lower.



Mass SREC Database Trend: Average Cost (Sept 2011-August 2012)





Mass SREC Database: Avg. - 1 Std. Deviation (Sept 2011 – August 2012)

Mass SREC Database – Avg. Installed Cost minus 1 Std Dev by Qtr. (\$/Watt)

Size Bin (kw)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
50-100	\$4.49	\$4.32	\$4.02	\$4.07
101-250	\$4.62	\$3.82	\$3.64	\$3.53
251-500	\$4.20	\$3.76	\$3.19	\$3.46
500+		\$3.67	\$3.70	\$3.20

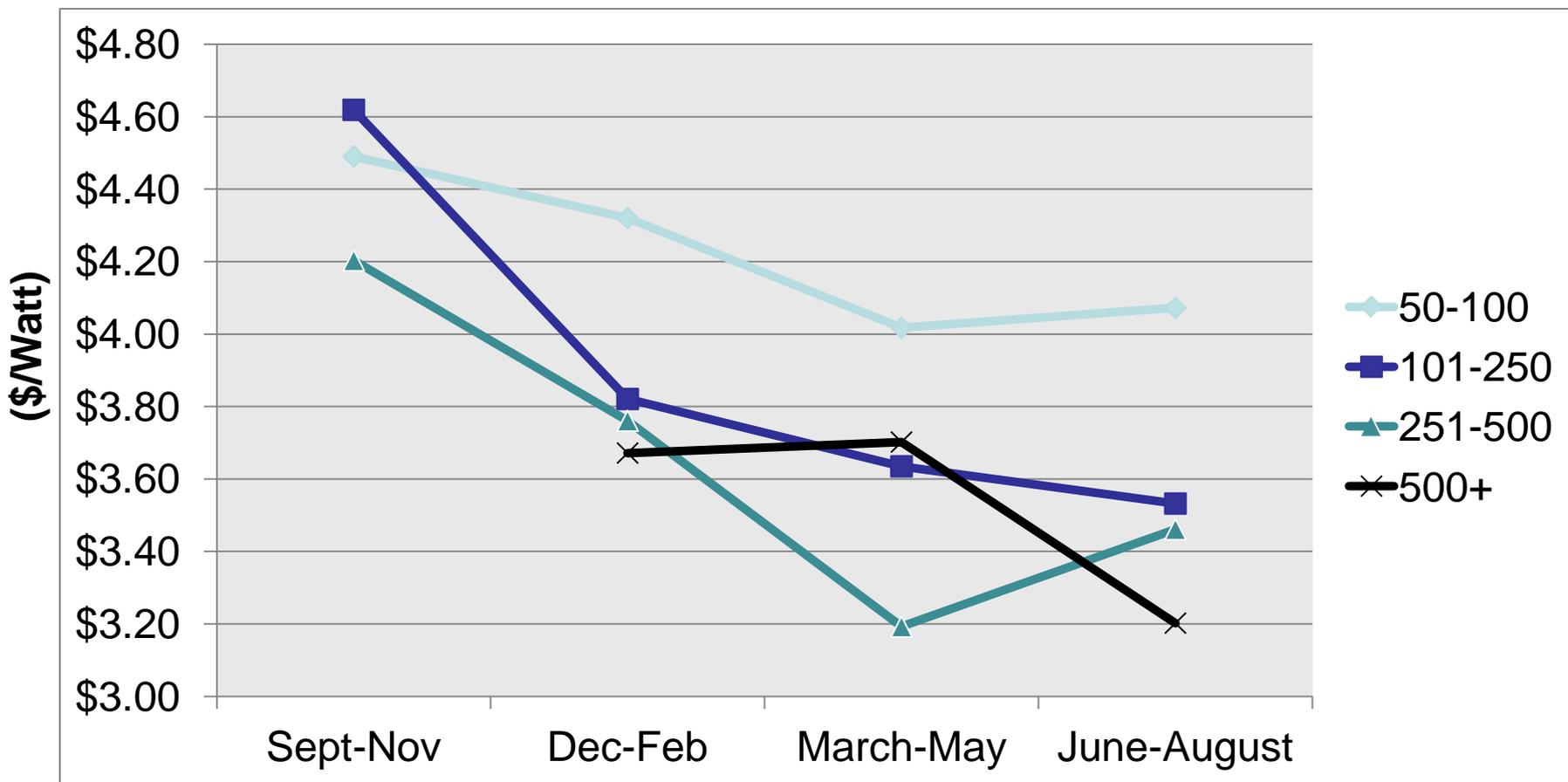
Mass SREC Database – Avg. Inst. Cost minus 1 Std Dev for Target Sizes by Qtr. (\$/Watt)

Size Bin (kw)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
350-650	\$4.06	\$3.99	\$3.79	\$2.88*
1000-2500		\$4.08	\$4.07	\$3.13

* StdDev not meaningful due to small sample size.



Mass SREC Database Minus 1 Standard Deviation (Sept 2011-August 2012)





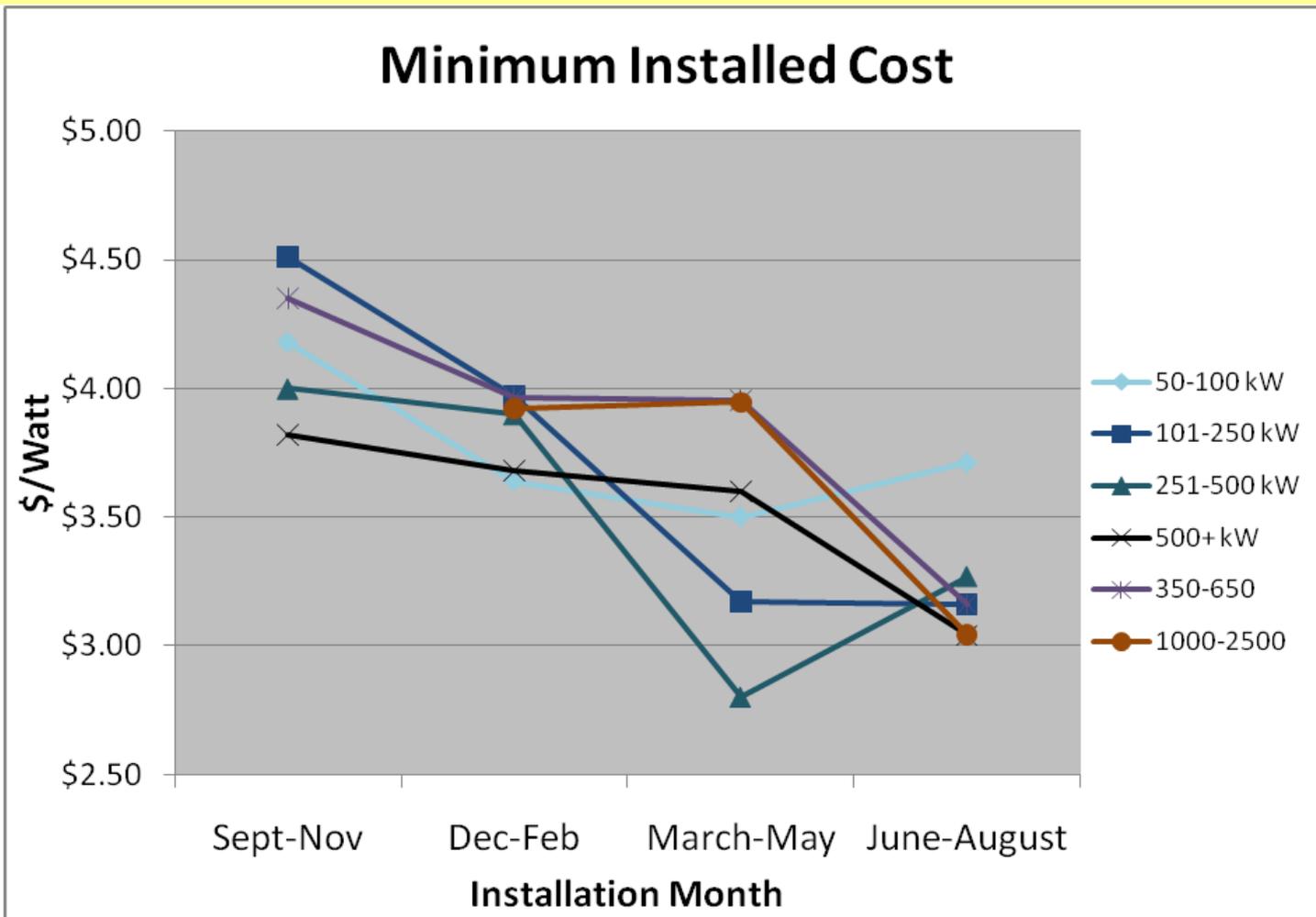
Mass SREC Database: Minimum Installed Cost in Each Bin

Bin	Installation Month (Range)	Min Installed Cost (\$/Watt)
50-100	Sept-Nov	\$4.18
	Dec-Feb	\$3.64
	March-May	\$3.50
	June-August	\$3.71
101-250	Sept-Nov	\$4.51
	Dec-Feb	\$3.97
	March-May	\$3.17
	June-August	\$3.16
251-500	Sept-Nov	\$4.00
	Dec-Feb	\$3.90
	March-May	\$2.80
	June-August	\$3.27
500+	Sept-Nov	\$3.82
	Dec-Feb	\$3.68
	March-May	\$3.60
	June-August	\$3.04

Target Size	Installation Month (Range)	Min Installed Cost (\$/Watt)
350-650	Sept-Nov	\$4.35
	Dec-Feb	\$3.96
	March-May	\$3.95
	June-August	\$3.16
1000-2500	Sept-Nov	
	Dec-Feb	\$3.92
	March-May	\$3.95
	June-August	\$3.04



Mass SREC Database: Minimum Installed Cost in Each Bin





NREL National PV Cost Estimates

	Mean Costs (\$/Watt)	St Dev	Mean – 1 St Dev
<10 kW	\$4.78	\$0.82	\$3.96
10-100	\$4.43	\$0.54	\$3.89
100-1000	\$3.67	\$0.67	\$3.00
1-10MW	\$3.38	\$0.61	\$2.77

Data from: *Distributed Generation Renewable Energy Estimate of Costs*
National Renewable Energy Laboratory, July 2012

http://www.nrel.gov/analysis/pdfs/2012_dg_icoe_data.pdf



Operation & Maintenance (O&M) Cost

Sources

- NREL National PV Cost Estimates

Project Size	Fixed O&M (\$/kW-year)	O&M Std Dev
<10 kW	\$29	\$20
10-100 kW	\$26	\$19
100-1000 kW	\$24	\$13
1-10 MW	\$22	\$10

- MCG experience
- SEA experience
- Stakeholder DR

Mass SREC Database Descriptive Stats

Bin	Months	No.	Mean (\$/Watt)	StdDev	Max	Min
50-100	Sept-Nov	6	\$5.97	\$1.48	\$8.30	\$4.18
	Dec-Feb	16	\$5.59	\$1.27	\$7.83	\$3.64
	March-May	9	\$4.75	\$0.74	\$5.98	\$3.50
	June-August	8	\$4.85	\$0.78	\$5.97	\$3.71
101-250	Sept-Nov	8	\$5.14	\$0.52	\$5.75	\$4.51
	Dec-Feb	22	\$5.48	\$1.66	\$9.60	\$3.97
	March-May	12	\$4.76	\$1.13	\$7.07	\$3.17
	June-August	8	\$4.33	\$0.79	\$5.47	\$3.16
251-500	Sept-Nov	7	\$4.75	\$0.54	\$5.75	\$4.00
	Dec-Feb	8	\$4.78	\$1.02	\$6.78	\$3.90
	March-May	5	\$3.98	\$0.78	\$4.75	\$2.80
	June-August	4	\$4.00	\$0.54	\$4.52	\$3.27
500+	Sept-Nov	1	\$3.82	\$0.00	\$3.82	\$3.82
	Dec-Feb	8	\$5.25	\$1.58	\$7.80	\$3.68
	March-May	6	\$4.11	\$0.41	\$4.49	\$3.60
	June-August	9	\$4.10	\$0.89	\$5.76	\$3.04
1000-2500	Sept-Nov	0				
	Dec-Feb	5	\$5.75	\$1.67	\$7.80	\$3.92
	March-May	4	\$4.33	\$0.26	\$4.49	\$3.95
	June-August	4	\$3.98	\$0.85	\$5.05	\$3.04



Interconnection

Details, Sources

- National Grid:
 - data from Standard Offer bids, plus
 - random sample of 21 MA & RI projects
- Stakeholder DR



Finance Structure & Costs of Debt and Equity

Details, Sources

- Stakeholder Data Request
- SEA Experience
- Model optimized based on avail cash flows

NOTE:

- Available data suggest a wider range of equity returns than returned in response to the data request, with much lower costs on the low-end of the range possible. Scale and ability to replicate are important factors.
- NREL Renewable Energy Finance Tracking Initiative, 2011:
 - Avg. equity return for solar < 1 MW (Q4'09-2011): developer equity ~12%; tax equity ~11%
 - Tax equity: 1st half 2011 ~7.8%; 2nd half 2011 ~10%
 - Solar developer return variance within 200 bps; tax equity w/in 70 bps
 - Trend is generally downward for both cash and tax equity.



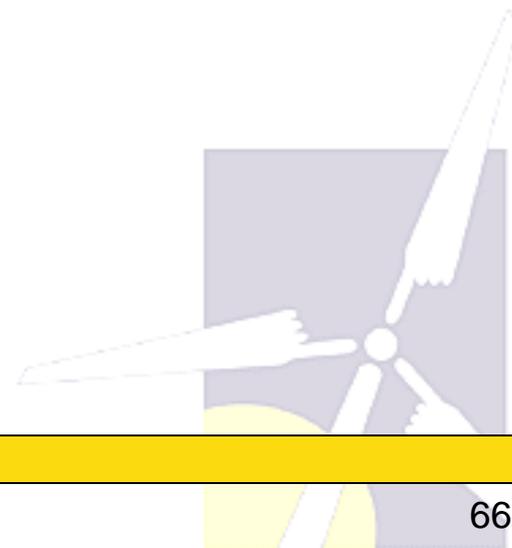
Performance

Details, Sources

- PV Watts assumes no tracking, idealized orientation & tilt
- Stakeholder Data Request
- Inverter conversion factor based on data request and manufacturer input
- MA CEC PTS: actual historic production
- Same adjustments as made in 2011.



APPENDIX B - WIND





Additional Comments

Turbine Capacity Limit:

- Employing a capacity limit of ~2.0 MW would better reflect market conditions. During the last several years, the availability of 1,500 kW turbines has decreased in favor of machines in the 1.6, 1.65, 1.8 and 2 MW range.

Transaction Costs:

- Legal expenses are highly variable, and an important factor until all project processes and documents can be standardized. Legal fees for a project in SEMA were \$400,000.

Financing Assumptions Post-PTC:

“We’ve not seen small [wind] projects pencil out without PTC for any reasonable return”

Behind the Meter

- *Thus far, 100 kW projects have been developed behind the retail meter, where the economics are more attractive due to net metering.*
- *Additional state-level grants have also played an important role for these projects.*



Capital Cost, Installed

(Includes soft costs & construction financing;
excludes Interconnection)

Details, Sources

- Stakeholder DR
- SEA Experience
- Interviews

Costs embedded in total installed cost estimates include:

Soft Costs: *development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*



O&M Cost

Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience



Interconnection

Details, Sources

- Stakeholder DR
- National Grid: random sample of projects in RI & MA



Finance Structure & Costs of Debt and Equity

Details, Sources

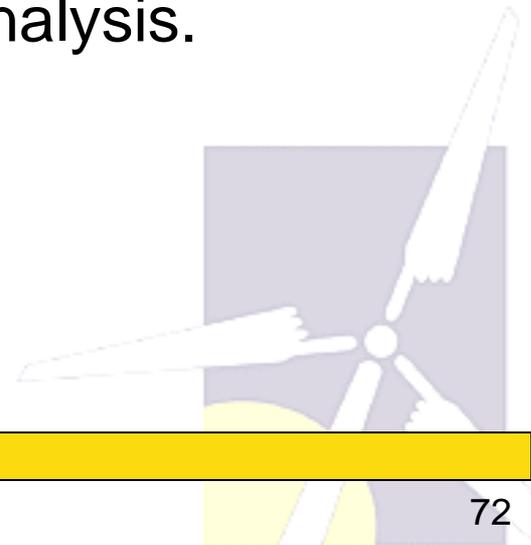
- Stakeholder DR
- Interviews
- SEA Experience
- Model optimized based on available cash flows



Performance

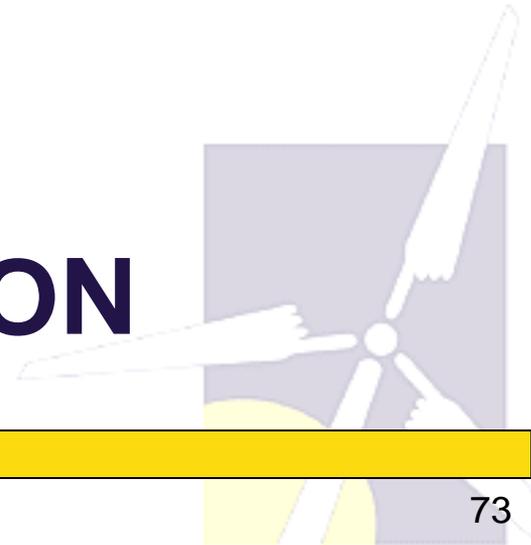
Details, Sources

- Stakeholder DR
- SEA Experience
- MA CEC PTS
- Adjustment made for recent improvements in low wind-speed turbine performance, per SEA analysis.





APPENDIX C – ANAEROBIC DIGESTION





Details, Sources

Capital Cost, Installed (Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder DR
- Interviews

Costs embedded in total installed cost estimates include:

Soft Costs: *development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

O&M

- Stakeholder DR

Interconnection

- Stakeholder DR

Finance Structure and Cost of Debt & Equity

- Stakeholder DR
- Model optimized based on available cash flows

Performance

- Stakeholder DR



Other Comments

- Costs and revenues (tipping fees) are highly variable and should be assessed on a per-project basis, especially related to digestate management.
- Also, there may be significant economies of scale. Inputs should be sought for each project.