Appendix B: Electricity Sector Strategy Analysis

INTRODUCTION

In this appendix, we detail the analytical steps behind four key components, specifically:

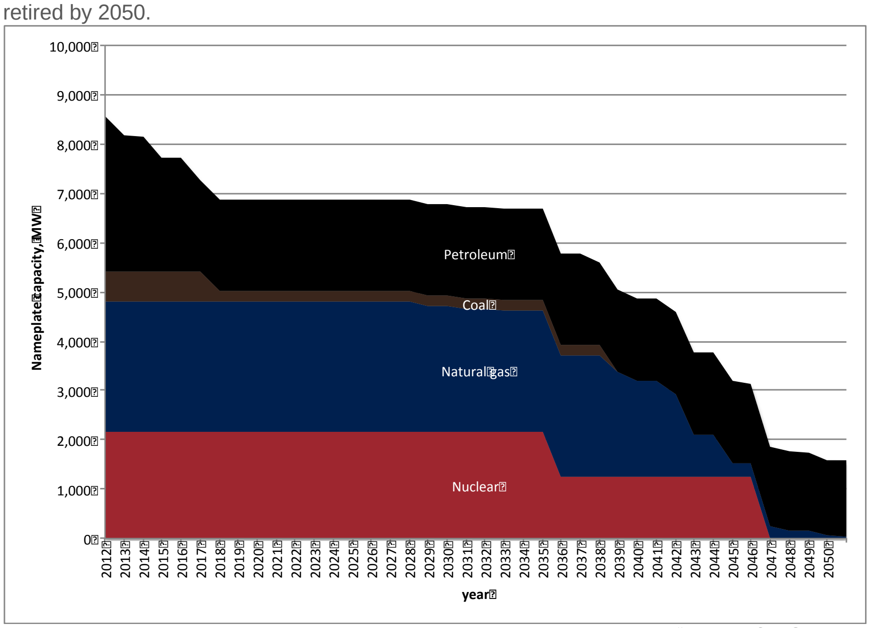
- The forecasted thermal generating retirements in Connecticut;
- The amount of Class I renewable energy required in 2020 for Connecticut to meet its Renewable Portfolio Standard;
- The technical potential and levelized costs of renewable resources in the New England region; and
- The costs and opportunity for cost reductions of solar photovoltaics.

FORECASTING THERMAL GENERATOR RETIREMENTS

New England's current generating fleet is aging. DEEP estimates that 99% of Connecticut's nuclear, natural gas, and coal power capacity and 95% of capacity in Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont will exceed average industry lifetimes by mid-century. The forecasted operating thermal capacity in Connecticut through 2050 is shown in Figure B-1.

Figure B-1: Forecasted operating thermal capacity in Connecticut

The U.S. Energy Information Administration lists 8,500 MW of thermal (nuclear, gas, coal, and oil) generating capacity operating today in Connecticut. Assuming industry average lifetimes, nearly all of the nuclear, gas, and coal capacity will be retired by 2050.



Analysis based on: U.S. EIA, *Existing Generating Units*; and Hodgkins, "Wave of U.S. Retirements."

The primary input for this analysis comes from the U.S. Energy Information Administration's Form-860, "Existing Generating Units in the United States by State and Energy Source."[1] This table lists all existing

[1] U.S. Energy Information Administration (EIA), "Existing Generating Units." Available at http://www.eia.gov/electricity/capacity/

electrical generators in Connecticut, along with their nameplate capacities (MW), fuel, operational status, and month and year of initial operation, from which DEEP determined the current age of each plant.

The second key input to this analysis is the assumed retirement age of these plants. As reported in the trade journal *SNL Power Daily*, a 2012 Bernstein & Co. report calculated the average retirements ages of U.S. coal-fired, gas-fired (combustion turbines), and oil-fired plants to be 49, 40, and 41 years, respectively.[2] DEEP used these assumed retirement ages for all fossil-fired power plants; for nuclear reactors, DEEP used the actual years when their current licenses will expire, (e.g., 2035 and 2045 for Millstone 2 and 3).[3]

Using the age of each plant and its expected retirement age (should it follow industry norms), a simple calculation gives the retirement year of each plant and the forecasted operating capacity in each year between now and 2050 (when the analysis period ends). However, not all the system operating capacity will necessarily run in any given year. For example, Connecticut currently has 2,900 MW of oil-fired capacity listed as "operational" in form EIA-860, but generated only 408,000 MWh from oil-fired plants in 2010.[4] This amounts to a fleet-wide 2% capacity factor, meaning that the vast majority of these oil-fired power plants are no longer running on any regular basis. This means that the actual operating lifetimes of Connecticut's oil-fired plants may be extended beyond those shown in Figure A-1, although these plants will likely continue to be far underutilized.

CLASS I RENEWABLE ENERGY REQUIRED TO MEET RPS

Connecticut's Renewable Portfolio Standard (RPS), established in 1998, imposes annual requirements on the percentage of retail sales that must be generated from qualifying renewable resources. The terminal requirement is a 20% Class I renewable portfolio by 2020, although there are intermediate targets as well.5

The forecasted annual electricity load for Connecticut in 2020 in this Draft Strategy's "Expanded Energy Efficiency" scenario is 30,981 GWh. (For more details, see the Efficiency and Industry Technical Appendix). Meeting the RPS with this load would require 6,196 GWh of Class I generation in 2020.

Because of differing capacity factors, generating this amount of renewable electricity would require different nameplate capacities of wind, solar, or other renewables. The 2012 Integrated Resource Plan (IRP) assumed annual capacity factors of 13% for solar PV, 27.9% for onshore utility-scale wind, and 37% for offshore wind in Connecticut.6 With a 50/50 split between solar PV and wind (and assuming the wind

[2] Hodgkins, Jay. "Wave of U.S. Plant Retirements Likely Approaching; IPPs Particularly Exposed." SNL Power Daily, April 25, 2012. Available at http://http://publicutilities.utah.gov/news/waveofusplantretirementslikelyapproaching.pdf.
[3] U.S. Nuclear Regulatory Commission. NRC Renews Millstone Nuclear Power Station Operating Licenses for an Additional 20 Years. NRC News no. 05-161. Washington DC: Office of Public Affairs, 2005. Available at http://www.nrc.gov/reading-rm/doc-collections/news/2005/05-161.html.
[4] U.S. Energy Information Administration (EIA), "Existing Generating Units." Data from Form EIA-860. Washington DC: U.S. Energy Information Administration, 2010.
[5] Conn. Gen. Stat. §16-245a.
[6] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/cwp/view.asp?a=4120&q=486946.

is half onshore, half offshore—much of which will likely be accessed from outside the state), it would take 1.09 GW of wind and 2.72 GW of solar PV to generate 6,196 GWh/year. These figures illustrate technical potential and are only provided for illustrative purposes. Itwould be highly unlikely that those levels of offshore or onshore wind could be sited or financed in the near term. Of course, many other resource mixes are possible.

POTENTIAL AND COSTS OF NEW ENGLAND'S RENEWABLE RESOURCES

Table 1 in Chapter 3 (Electricity) lists the technical potential of renewable resources in the New England region, as well as ranges of the levelized cost of energy from each resource with and without existing Federal subsidies.

TECHNICAL POTENTIAL

For all resources listed in Table B-1 (solar, wind, biomass, small hydro, enhanced geothermal), the technical potential numbers are taken directly from a 2012 study from the National Renewable Energy Laboratory (NREL).7 This report estimated the state-by-state technical potential of these resources, both on a capacity (GW) and annual energy (GWh/year) basis.

Technical potential is an estimate of the electricity generation potential of a resource based on the availability and quality of the resource, technical performance of current systems, and constraints based on land topography and environmental or other uses. *Technical potential does not include economic or market considerations, such as fuel or technology costs, the impacts of policy, or projected market uptake. Additionally, in nascent industries such as these, costs are extremely variable.*

As an example, the NREL study calculates onshore wind potential by first taking the wind resource in each state and then removing available sites such as airports, urban areas, wetlands, water, National Park Service Lands, Fish & Wildlife Lands, Federal Parks/Wilderness/National Monument/Recreation Area/Wildlife Refuge, and so on. The study also excludes land with a slope greater than 20%, where construction and maintenance of wind turbines would be challenging. After land exclusions, the study estimates the technical potential for wind power assuming all remaining available land is developed with the best available wind turbine technology today.

While the technical potential gives insight into the amount of a resource that is available, it should be noted that 1) it is very difficult and unlikely that all, or even a large fraction, of the potential could be developed, and 2) the technical potential of a resource is not fixed in time. For example, better turbine technology that allows greater efficiency over a range of wind speeds or denser packing of wind turbines

[7] Lopez, Anthony, Billy Roberts, Donna Heimiller, Nate Blair, and Gian Porro. U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. NREL/TP-6A20-51946. Golden, CO: National Renewable Energy Laboratory, 2012. Available at http://www.nrel.gov/docs/fy12osti/51946.pdf

would increase the amount of the wind energy resource that could be captured, and better construction methods may allow development on lands with up to 30% slope.

For full details on state-by-state technical potential of renewable resources and the embedded assumptions, see the referenced report.

The Draft Strategy also highlights Canadian hydropower (not included in the NREL study) as a potential low-carbon generation resource. The resource potential of Canadian hydropower is enormous. Hydro Quebec is currently planning development of 4,500 MW of large-scale hydro projects; much more potential remains untouched.[8] Of course, the vast majority of this resource is inaccessible today due to lack of transmission connections. There is currently a proposal for a large direct current transmission line that would bring hydropower from Quebec into New Hampshire.[9] This line has a proposed capacity of 1,200 MW, meaning that the maximum energy import into New England from this project would be 1,200 MW x 8,760 hr/y, or 10,512 GWh/y. Of course, additional transmission projects would increase the portion of Canadian hydropower potential that New England could utilize.

LEVELIZED COSTS OF ENERGY

The levelized cost of energy (LCOE) divides the present value of all lifetime cash flows (capital cost, operations and maintenance costs, fuel costs, taxes, and rebates or subsidies) of a generating asset by the present value of all lifetime electricity generation to arrive at a $/kWh number.[10] LCOEs can be used to directly compare investments in different technologies, and to compare generation costs against retail or wholesale electricity rates.

Calculating the LCOE for a given generation asset is straightforward, but requires assumptions around fuel prices, capital and operation costs, and discount and interest rates. These can introduce large sensitivities into a project's LCOE.

The ranges of LCOEs in Table A-1 come from a variety of sources. The assumptions and calculations are detailed below.

1. Wind, fuel cell, small hydro, and biopower

DEEP used input assumptions from the 2012 IRP, including assumptions for financing, capital cost, operating lifetime, and operating costs. In addition to these assumptions, DEEP calculated LCOEs for wind and fuel cells using recent capital cost estimates from Lazard, a U.S. investment bank.[11] These are

[8] Hydro Quebec. "Developing Quebec's Hydropower Potential." Accessed July 21, 2012. Available at http://hydroforthefuture.com/projets/9/developing-quebec-s-hydropower-potential.
[9] Federal Energy Regulatory Commission. *"*Order Granting Petition for Declaratory Order. FERC Docket no. EL09-20-000.*"* Washington DC: Federal Energy Regulatory Commission, 2009.
[10] Calculating the present value of future cash flows requires discounting them using a chosen *discount rate.* In the same way, we can discount future electricity generation, because 1 kWh generated in the future is worth less to us today than 1 kWh generated this year. See the model documentation in NREL, "System Advisor Model."
[11] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/cwp/view.asp?a=4120&q=486946.

shown below in Table B-1, along with the current value of the Federal production tax credit for these resources.[12] These incentives are paid to the project developer for all electricity generation from the project for the first 10 years.

Table B-1: Input assumptions used in LCOE calculations for renewable energy systems.

Resource	*Lazard Capital Cost ($/kW)*	*IRP Capital cost ($/kW)*	*Fixed O&M ($/kW-y)*	*Variable O&M ($/MWh)*	*Annual capacity factor*	*Federal tax credit ($/MWh)*
Onshore wind	1,750	2,498	28.80	-	24%–35%	23.6 (production tax credit)
Offshore wind	4,050	5,508	159.80	-	37%	23.6 (production tax credit)
Fuel cell	5,400	7,081	2.30	35.90	90%	30% of capital cost (investment tax credit)
Small hydro		3,151	13.80	-	48%	11.8 (production tax credit)
Biopower		3,954	103.00	5.10	85%	11.8 (production tax credit)

Source: Connecticut DEEP, *2012 Integrated Resource Plan;* North Carolina State University, "Renewable Electricity Production Tax Credit"; and Lazard, Levelized Cost Energy Analysis[13]

A 10.8% capital charge rate was applied for all resources. More information on the financing assumptions that underpin this capital charge rate is presented in Appendix D of the 2012 IRP.[14]

2. Solar photovoltaics (PV)

For solar PV, DEEP used capital cost data from real projects installed in Connecticut. These cost data were provided by the Clean Energy Finance and Investment Authority (CEFIA).[15] Since these installations were not utility scale, DEEP did not use the financing assumptions from the 2012 IRP. Instead, DEEP used the National Renewable Energy Laboratory's System Advisor Model and its default

[12] North Carolina State University, "Database of State Incentives for Renewables & Efficiency: Federal Renewable Electricity Production Tax Credit." Last modified May 22, 2012. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1.

[13] Lazard. Levelized Cost of Energy Analysis – Version 6.0. New York: Lazard, 2012. Available at http://blog.cleanenergy.org/files/2009/04/lazard2009_levelizedcostofenergy.pdf

[14] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/cwp/view.asp?a=4120&q=486946.

[15] Clean Energy Finance and Investment Authority. "PowerClerk Data Export." Microsoft Excel file shared with Connecticut Department of Energy and Environmental Protection. May 14, 2012; and Clean Energy Finance and Investment Authority.; "PV On Site Project Dashboard." Microsoft Excel file shared with Connecticut Department of Energy and Environmental Protection. April 30, 2012.

inputs to calculate the levelized cost of energy for rooftop solar PV. The detailed assumptions from NREL's System Advisor Model (SAM) are discussed in the next section of this appendix.

The average LCOE of commercial rooftop solar PV projects in 2012 is 20.8 ¢/kWh without subsidies and 12.8 ¢/kWh counting the 30% Federal investment tax credit (ITC). The average LCOE of 2012 residential solar PV projects is 35.8 ¢/kWh without subsidies and 28.2 ¢/kWh with the Federal ITC. Thus the Draft Strategy lists the range of installed costs as 17.4–35.8 ¢/kWh with no subsidies and 9.4–28.2 ¢/kWh with subsidies (see section below on *Solar PV Costs and Opportunities* for full details on these calculations, including our financial assumptions).

There are very few utility-scale PV projects in Connecticut, and again, cost data are not available for those that do exist. In 2011 DEEP issued a solicitation for 10 MW of utility-scale solar PV, and accepted two bids with average all-in costs of 22 ¢/kWh. DEEP used this cost range for utility-scale PV with subsidies (because bidding parties included the ITC in their financial calculations before arriving at a bid price), and inflated this cost to get an estimate of the range of costs without subsidies.

ANALYSIS OF SOLAR PHOTOVOLTAICS COSTS AND OPPORTUNITIES

A standard cost metric in the solar industry is the total installed cost of a project on a $/W basis. Typically, this is reported for the nameplate direct current electrical capacity, giving it the units *$/W-dc*. To make the analysis and recommendations of this strategy more accessible to a wide audience not familiar with $/W benchmarks, and to allow for easy comparison to the retail price of electricity and other generation technologies, all installed costs have been converted to *levelized costs of energy* ($/kWh).

OVERVIEW

The primary data source for the solar PV analysis is a dataset of residential and commercial projects in the Connecticut provided by the Clean Energy Finance and Investment Authority (CEFIA).[16] This dataset includes all projects that applied for CEFIA incentives between 2001 and the present, with detailed information for each project, including:

- Project classification (residential/commercial)
- Application submittal and approval dates
- Details (program name and step) and values ($/W) of incentives given
- Total system cost and incentive amount ($)
- System size, including capacity (direct current and alternating current ratings) and expected annual production (kWh)
- Project cost broken down into: modules, inverter(s), monitoring device(s), engineering & design, installation labor, permitting fees, interconnection fees, municipal and utility inspections, and

[16] Ibid.

balance of system. These data were self-reported by installers, and there is some, unknown, variation in the way different installers break down total cost by components.

- Manufacturer and model details for key hardware components

A similar dataset ,without the component cost breakdown, was downloaded from the website of Go Solar California, California's solar campaign coordinated by the California Energy Commission and Public Utilities Commission.[17]

TOOLS

DEEP used NREL's SAM to convert installed $/W-dc costs to $/kWh LCOEs.[18] In its calculator for solar PV systems, SAM has five key modules that are important for this analysis: climate, financing, tax credit incentives, annual performance, and PV system costs.

1. Climate

Climate is one of the largest factors affecting the LCOE of a solar PV system. Solar insolation varies dramatically across different regions of the United States. For example, Phoenix, AZ receives an average of 2,519 kWh/m^2-yr of direct beam insolation, while Anchorage, AK receives only 857 kWh/m^2-yr.[19] A system built in Anchorage with exactly the same installed cost, incentives, and financing as a system built in Phoenix will have an LCOE that is roughly three times higher.

In this analysis, we assumed all systems were built in Hartford, CT, which has an average insolation value of 1,178 kWh/m^2-yr.[20]

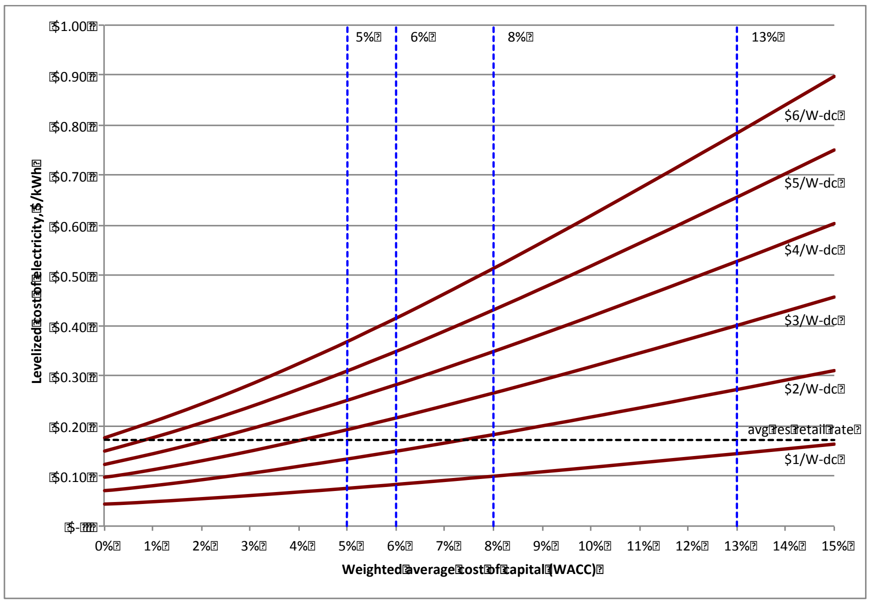
2. Financing

Financing can also have a huge impact on the LCOE of a solar PV system. Figure 2 shows how the LCOE of a residential system with fixed $/W-dc installation cost varies with the weighted average cost of capital. At an installed cost of $4/W-dc, for example, the LCOE can vary between $0.25/kWh and $0.53/kWh as the WACC goes from 5–13%, a reasonable range for financing residential projects.

[17] Go Solar California. "California Solar Statistics." Accessed May 2012. Available at http://www.californiasolarstatistics.ca.gov/
[18] National Renewable Energy Laboratory. "System Advisor Model (Version 2011.6.30)." [Software]. Golden, CO: National Renewable Energy Laboratory, 2011. Available at https://sam.nrel.gov.
[19] Ibid.
[20] Ibid.

Figure B-2: Levelized cost of energy vs. weighted average cost of capital for residential solar PV systems in Connecticut.

The LCOE of electricity generating projects (in this case solar PV) is highly dependent on not only the initial capital cost but also the cost of financing the project.



Analysis based on: CEFIA, "Power Clerk Data Export"; CEFIA, "On Site Project Dashboard"; and NREL, "System Advisor Model."

The strong dependence of the LCOE on the cost of capital means that the LCOEs for solar PV systems presented in this Draft Strategy's electricity chapter are not exact, but are merely representative of typical projects.

To convert installed $/W-dc costs to LCOEs in this analysis, DEEP used the financial inputs in Table B-2. Most of these values are the model defaults used by NREL based on industry standards (for example, a 25y analysis period/system lifetime). DEEP adjusted the State and sales tax rates to true values in Connecticut (residential solar PV systems are exempt from sales tax). The assumed interest rate for residential systems is 7.75%; this is the NREL default value, and is representative of current interest rates in the new FHA PowerSaver loan for financing residential efficiency or distributed generation projects (100% debt, 6–9% cost of capital).[21] For commercial systems DEEP used an interest rate of 10.68%, resulting in a WACC of 7% (consistent with the assumed WACC in the 2012 IRP).[22] The most critical difference between residential and commercial systems is the inclusion of depreciation in commercial systems, which we assume is handled with 5-yr Modified Accelerated Cost Recovery System (MACRS).

[21] U.S. Department of Housing and Urban Development. Federal Housing Administration (FHA): Notice of FHA PowerSaver Home Energy Retrofit Loan Pilot Program. Docket no. FR-5450-N-03. Washington DC, 2011.
[22] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/cwp/view.asp?a=4120&q=486946.

Table B-2: Financial assumptions used in $/W to LCOE conversions for solar PV systems.

Parameter	Value (residential)	Value (commercial)
General parameters		
Analysis period	25y	25y
Inflation rate	2.50%	2.50%
Real discount rate	5.00%	5.00%
Taxes		
Federal tax rate	28.00%	28.00%
State tax	5.00%	9.00%
Sales tax	0.00%	6.35%
Loan parameters		
Loan type	Standard loan	Standard loan
Debt fraction	100%	100%
Loan term	25y	15y
Loan rate	7.75%	10.68%
Depreciation	N/A	5y MACRS

Source: NREL, “System Advisor Model”; Tax Foundation, “Connecticut”; and Connecticut DEEP, *2012 Integrated Resource Plan*.

3. Tax Credit Incentives

Because federal and state incentives for solar PV are provided to the customer (or installer) post-installation, the *installed cost* of a solar PV system is the same with or without counting incentives. However, the inclusion of federal or state incentives affects the lifetime cash flows, which means it will affect the levelized cost of electricity from the project. In the Electricity chapter of this Draft Strategy, LCOE results for solar PV projects are presented without counting state incentives, but counting the Federal 30% ITC.[23] The justification for this is that the Federal ITC is a very real piece of the picture; one over which the state has no control, and which is slated to continue at its current levels until at least 2016.

4. Annual Performance, PVWatts Solar Array

Default values were left under annual performance: 0.5% system degradation per year and 100% system availability. The PVWatts Solar Array module lets the SAM user select various system design and performance parameters. We chose to model fixed, south facing, 20 degree tilt systems with a direct current to alternating current derating factor of 0.77 (this includes all inefficiencies including inverter, line losses, shading, and module mismatch). A local installer confirmed this derating factor (NREL’s default value) to be a reasonable value for systems in Connecticut.

[23] North Carolina State University. “Database of State Incentives for Renewables & Efficiency: Federal Business Energy Investment Tax Credit (ITC).” Last modified November 28, 2011. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1.; and North Carolina State University, “Database of State Incentives for Renewables & Efficiency: Federal Residential Renewable Energy Tax Credit.” Last modified December 20, 2011. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F&re=1&ee=1.

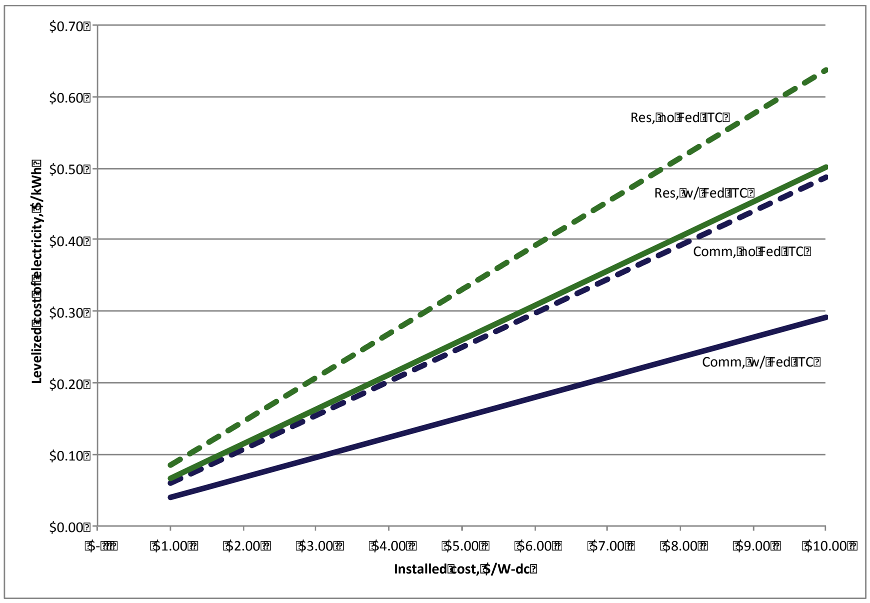
5. PV System Costs

In the PV System Costs module, DEEP adjusted the total system cost to $1/W-dc, $2/W-dc, etc., to calculate the LCOE for a given installation cost with the above climate, financing, incentive, and performance assumptions.

RESULTS

Given the above inputs and assumptions in SAM, DEEP calculated the LCOE of residential and commercial systems in Connecticut at a range of installed costs between $1–10/W-dc. These results are shown below in Figure A-3.

Figure B-3: Levelized cost of energy vs. installed cost for solar PV systems in Connecticut.
With all climate, financial, and system assumptions fixed, the LCOE ($/kWh) is an (almost) linear function of the installed cost ($/W-dc). At the same installed cost, a commercial system has a lower LCOE than a residential system due to better financing and the inclusion of deprecation.



Analysis based on: NREL, “System Advisor Model”; Tax Foundation, “Connecticut”; North Carolina State University, “Business Energy Investment Tax Credit”; North Carolina State University, “Residential Renewable Energy Tax Credit”; and Connecticut DEEP, *2012 Integrated Resource Plan*.

The relationship between installed cost and LCOE is nearly linear. Thus, for converting all $/W-dc costs (from the CEFIA project dataset) to LCOEs, DEEP used the following slopes $\left(\frac{\$/kWh}{\$/W-dc}\right)$:

- Commercial, no Federal ITC: 0.051
- Commercial, with Federal ITC: 0.031
- Residential, no Federal ITC: 0.067
- Residential, with Federal ITC: 0.053

With the above slopes, converting all installed costs in the CEFIA project database was straightforward and resulted in the LCOE values as discussed in the Electricity chapter. These values can then be compared directly against the retail rates for electricity in the residential and commercial sectors, and against LCOEs for other generation technologies, many of which do include fuel or other lifetime operating costs. They cannot be compared against solar PV directly on a capital cost basis.

To create the waterfall chart showing the opportunity available for cost reductions in residential solar PV in Connecticut (Figure B-3), DEEP used the component cost breakdowns included in the CEFIA project dataset along with the $/W to LCOE multipliers listed above. Table B-3 shows the numeric results presented in Figure B-3.

Table B-3: Opportunity for cost reductions in residential solar PV in Connecticut.
This table presents the numeric data behind Figure 6 in the Electricity chapter.

	$/W-dc	LCOE (no Fed ITC)	LCOE (w/ Fed ITC)
Average total system cost (CT)	$5.24	$0.354	$0.353
Average total system cost (Germany)	$2.24	$0.151	$0.119
Total system cost with best quartile component costs (CT)	$3.07	$0.207	$0.163
Total system cost with best decile component costs (CT)	$2.31	$0.156	$0.123
Hardware			
Module – average	$2.23	$0.150	$0.118
Module – best quartile	$1.50	$0.101	$0.080
Module – best decile	$1.30	$0.088	$0.069
Inverters – average	$0.69	$0.047	$0.037
Inverters – best quartile	$0.50	$0.034	$0.027
Inverters – best decile	$0.41	$0.028	$0.022
Monitoring device – average	$0.11	$0.007	$0.006
Monitoring device – best quartile	$0.07	$0.005	$0.004
Monitoring device – best decile	$0.05	$0.003	$0.003
Design & Installation			
Eng. & Design – average	$0.16	$0.011	$0.008
Eng. & Design – best quartile	$0.06	$0.004	$0.003
Eng. & Design – best decile	$0.03	$0.002	$0.002
Installation labor – average	$0.91	$0.061	$0.048
Installation labor – best quartile	$0.50	$0.034	$0.027
Installation labor – best decile	$0.32	$0.022	$0.017
Permitting & Interconnection			
Pmt & Int'c fees – average	$0.12	$0.008	$0.006
Pmt & Int'c fees – best quartile	$0.06	$0.004	$0.003
Pmt & Int'c fees – best decile	$0.03	$0.002	$0.002
Inspection fees – average	$0.04	$0.003	$0.002

Inspection fees – best quartile	$0.00	-	-
Inspection fees – best decile	$0.00	-	-
Balance of system			
BOS – average	$0.98	$0.066	$0.052
BOS – best quartile	$0.39	$0.026	$0.021
BOS – best decile	$0.17	$0.011	$0.009

Analysis based on data from CEFIA, “PowerClerk Data Export”; CEFIA, “PV On Site Project Dashboard”; and Wesoff, “Germany Solar Installations.”