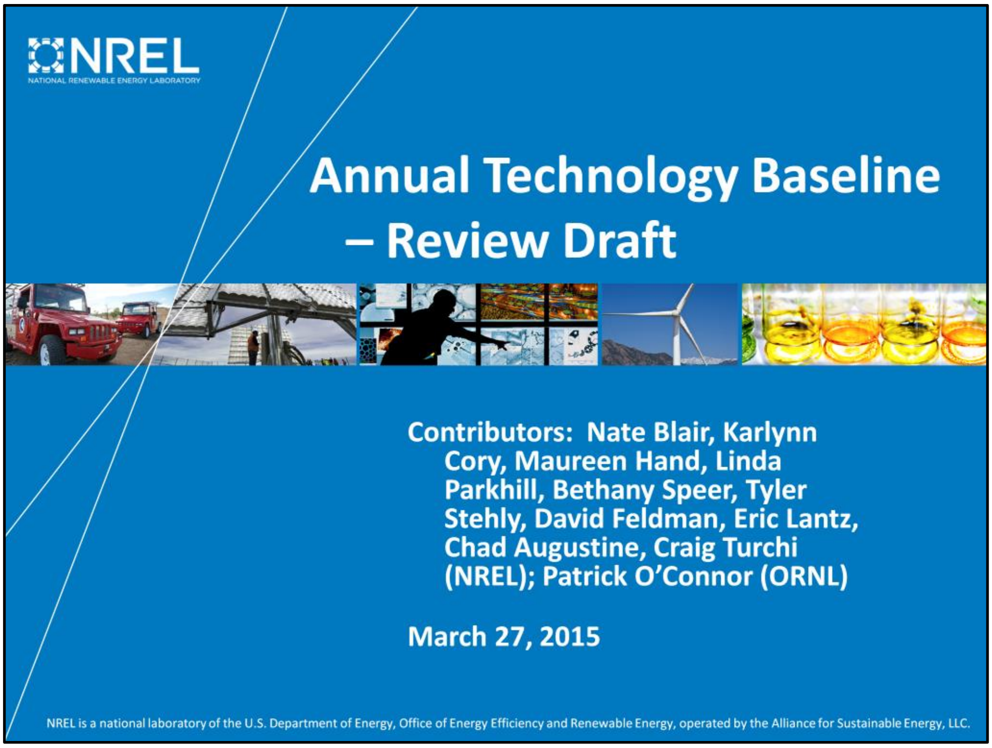


Notes pages provide additional detail and are essential for interpreting information on slides.
Excel spreadsheet accompanies this documentation and contains all input data and calculations illustrated on subsequent pages.

All monetary values presented in 2013 U.S. dollars.

Disclaimer

DISCLAIMER AGREEMENT

These detailed generation technology cost and performance data (("Data") are provided by the National Renewable Energy Laboratory ("NREL"), which is operated by the Alliance for Sustainable Energy LLC ("Alliance") for the U.S. Department of Energy (the "DOE").

It is recognized that disclosure of these Data is provided under the following conditions and warnings: (1) these Data have been prepared for reference purposes only; (2) these Data consist of forecasts, estimates or assumptions made on a best-efforts basis, based upon present expectations; and (3) these Data were prepared with existing information and are subject to change without notice.

The names DOE/NREL/ALLIANCE shall not be used in any representation, advertising, publicity or other manner whatsoever to endorse or promote any entity that adopts or uses these Data. DOE/NREL/ALLIANCE shall not provide any support, consulting, training or assistance of any kind with regard to the use of these Data or any updates, revisions or new versions of these Data.

YOU AGREE TO INDEMNIFY DOE/NREL/ALLIANCE, AND ITS AFFILIATES, OFFICERS, AGENTS, AND EMPLOYEES AGAINST ANY CLAIM OR DEMAND, INCLUDING REASONABLE ATTORNEYS' FEES, RELATED TO YOUR USE, RELIANCE, OR ADOPTION OF THESE DATA FOR ANY PURPOSE WHATSOEVER. THESE DATA ARE PROVIDED BY DOE/NREL/ALLIANCE "AS IS" AND ANY EXPRESS OR IMPLIED WARRANTIES, INCLUDING BUT NOT LIMITED TO, THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE ARE EXPRESSLY DISCLAIMED. IN NO EVENT SHALL DOE/NREL/ALLIANCE BE LIABLE FOR ANY SPECIAL, INDIRECT OR CONSEQUENTIAL DAMAGES OR ANY DAMAGES WHATSOEVER, INCLUDING BUT NOT LIMITED TO CLAIMS ASSOCIATED WITH THE LOSS OF DATA OR PROFITS, WHICH MAY RESULT FROM AN ACTION IN CONTRACT, NEGLIGENCE OR OTHER TORTIOUS CLAIM THAT ARISES OUT OF OR IN CONNECTION WITH THE USE OR PERFORMANCE OF THESE DATA.

Preface

This presentation is one of several products resulting from an initial effort to provide a consistent set of technology cost and performance data and to define a conceptual and consistent scenario framework that can be used in NREL's future analyses. The long-term objective of this effort is to identify a range of possible futures of the U.S. electricity sector in which to consider specific energy system issues through (1) defining a set of prospective scenarios that bound ranges of key technology, market, and policy assumptions; and (2) assessing these scenarios in NREL's market models to understand the range of resulting outcomes, including energy technology deployment and production, energy prices, and CO_2 emissions.

The specific products from the initial effort include the following:

- An Annual Technology Baseline (ATB) workbook documenting detailed cost and performance data (both current and projected) for both renewable and conventional technologies.
- **This ATB summary presentation describing each of the technologies and providing additional context for their treatment in the workbook.**
- A 2015 Standard Scenarios Annual Report describing the identified scenarios, associated assumptions (including technology cost and performance assumptions from the ATB), modeled results, and the base structure of the specific version of the ReEDS model (v2015.1) (annual "release") used to generate the results.

These products can be accessed at http://www.nrel.gov/analysis/data_tech_baseline.html.

Preface

This presentation is one of several products resulting from an initial effort to provide a consistent set of technology cost and performance data and to define a conceptual and consistent scenario framework that can be used in NREL's future analyses. The long-term objective of this effort is to identify a range of possible futures of the U.S. electricity sector in which to consider specific energy system issues through (1) defining a set of prospective scenarios that bound ranges of key technology, market, and policy assumptions; and (2) assessing these scenarios in NREL's market models to understand the range of resulting outcomes, including energy technology deployment and production, energy prices, and CO_2 emissions.

The initial effort, supported by the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), has focused on the electric sector by creating a technology cost and performance database, defining scenarios, documenting associated assumptions, and generating modeled results using NREL's Regional Energy Deployment Systems Model (ReEDS). This work leverages and continues significant activity already being funded by EERE for individual technologies and market segments.
The specific products from the initial effort including the following:

- An Annual Technology Baseline (ATB) workbook documenting detailed cost and performance data (both current and projected) for both renewable and conventional technologies.
- **This ATB summary presentation describing each of the technologies and providing additional context for their treatment in the workbook.**
- A 2015 Standard Scenarios Annual Report describing the identified scenarios, associated assumptions (including technology cost and performance assumptions from the ATB), modeled results, and the base structure of the specific version of the ReEDS model (v2015.1) (annual "release") used to generate the results.

These products can be accessed at http://www.nrel.gov/analysis/data_tech_baseline.html.

NREL intends to consistently apply these products in its ongoing electric sector scenarios analyses to ensure that the analyses incorporate a transparent, realistic, and timely set of input assumptions and consider a diverse set of potential futures. The application of standard scenarios, clear documentation of underlying assumptions, and model versioning is expected to result in

- improved transparency of critical input assumptions and modeling methodologies;
- improved comparability of results across studies;
- improved consideration of the potential economic and environmental impacts of generation technology improvement, changes in market conditions, and changes to policies and regulations; and
- an enhanced framework for formulating and addressing new analysis questions.

NREL plans to update the scenario framework and technology baseline annually and extend it to other technologies, models, and sectors, including transportation and the built environment.

Recent NREL Scenario Analyses

- 20% Wind Energy by 2030 (2008)
- Evaluating a Proposed 20% National Renewable Portfolio Standard (2009)
- SunShot Vision Study (2012)
- Renewable Electricity Futures Study – Exploration of High-Penetration Renewable Electricity Futures (2012)
- Beyond Renewable Portfolio Standards (2013)
- Integrated Canada-US Power Sector Modeling with ReEDS (2013)
- ReEDS Modeling of the President's 2020 U.S. Renewable Electricity Generation Goal (2014)

- New Wind Vision Report (expected)
- New Hydropower Vision Study (Expected)

This effort (and the related standard scenarios effort) provides essential and transparent groundwork for NREL analyses, and also provides citable bases for the broader energy analysis community.

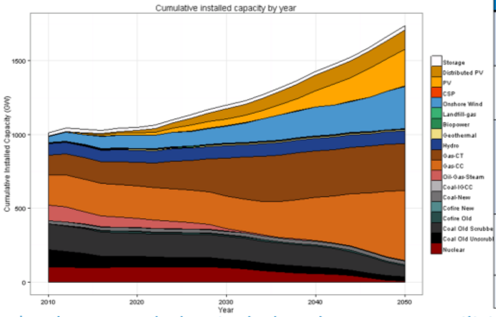
Annual Technology Baseline Objectives

- Develop consistent and normalized technology cost and performance assumptions
- Enable consistency in assumptions across analysis projects (and modeling).
- Mature the tracking and sourcing of input assumptions.
- Reduce the lead time for validating the consistency of analysis projects.
- Expand beyond the initial electric sector focus

NREL’s scenario analyses have become a hallmark capability. With the increased reliance on NREL's data and modeling tools for studies for EERE and other stakeholders, we collectively recognized the need and opportunity to establish a process to develop and communicate the underlying data and assumptions on which they are based. This is a logical outcome of the maturity of this capability.

Standard Scenarios and Relationship to ATB

- Create an ensemble of standard scenarios for the future – initially presented through NREL's ReEDS modeling results*
  - Illustrate the model's solution space
  - Provide a jump-start for analysis projects using ReEDS
  - Varying over anticipated drivers and specific storylines
- Publish an annual report of standard scenario results and modeling assumptions
- **The ATB provides the technology cost and performance assumptions for renewable and conventional technologies**



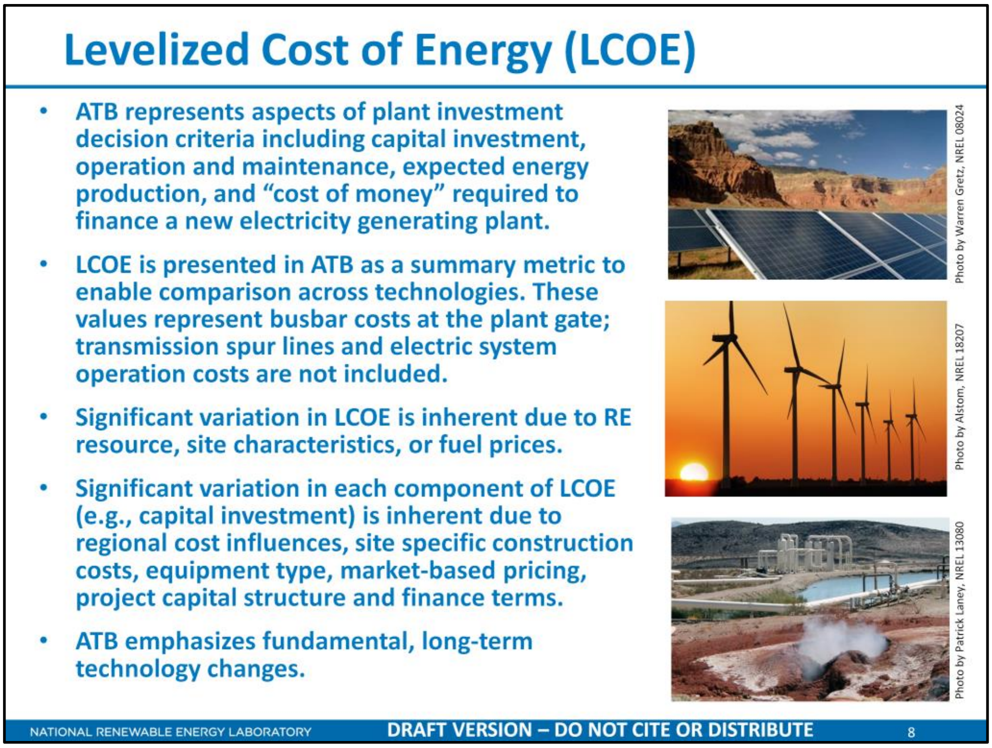
Group	Scenario	Notes
Fossil Fuel Costs	AEO 2014 Reference Fuel Cost	Fossil Fuel Cost Cases (AEO 2014): *Reference*: AEO 2014 NG and Coal Reference *Low*: High Oil & Gas Resource + Low Coal Price *High*: Low Oil & Gas Resource + High Coal Price
	Low NG and Coal Costs	
	High NG and Coal Costs	
Demand Growth	AEO 2014 Reference Demand Growth	Demand Growth Rate Cases: *Reference*: AEO 2014 Reference *Low EE Adoption*: AEO 2014 2013 Demand *High EE Adoption*: AEO 2014 High Demand
	AEO Low EE adoption	
	AEO High EE adoption	
Renewable Energy Technology Costs	High RE Cost	SunShot Scenarios for PV: *Reference*: 62.5% by 2020 going to 75% by 2040 *Low Cost*: 75% by 2020 *High Cost*: 50% by 2020 Wind Vision Scenarios for Wind: *Reference*: WV Median Reduction *Low Cost*: WV High Cost Reduction *High Cost*: WV Low Cost Reduction
	AEO 2014 Reference + Wind Vision	
	Low RE Cost	
	EERE Goals where available	
Retirements	MJB Planned + Ventyx Lifetimes	Extended Nuclear lifetime: Relicensing to 80 years available Accelerated Coal retirements: 50 yr lifetime if built after 1970 (from 65+) Accelerated retirement if built before 1970
	Extended nuclear lifetime	
	Accelerated coal retirement	
Policy/Regulatory Environment	Current Law	Alternative policies as specific storylines.

*To be expanded to include other sectors, utilizing other modeling platforms

Annual Technology Baseline (ATB)

- **Product: A populated framework to identify technology-specific parameters required to calculate levelized cost of energy (LCOE) or other investment decision metrics across a range of resource characteristics, sites, or fuel price assumptions for electricity-generation technologies at present and with projections through 2050.**
- Accompanying Excel spreadsheet includes all inputs and calculations illustrated on subsequent pages.
- Notes pages provide additional detail and are essential to interpreting information on subsequent pages.
- Product includes:
  - A comparison of input assumptions to recent historic trends; this demonstrates the extent to which model inputs represent current state of technology
  - Projections of future technology cost and performance relative to other published projections; these illustrate results among a variety of sources.
  - Normalization of definitions of variables
- This first edition of ATB focuses on utility-scale electricity generation technologies from the perspective of a utility that procures facilities and generates electricity. Distribution level (e.g., PV) and storage technologies will be considered for future editions.
- Future editions are planned to incorporate technologies outside the electric sector.

The utility perspective does not represent an emerging business model where a company manufactures components, constructs electricity generation facilities, and sells electricity (e.g., in the PV industry).



- LCOE **IS NOT** the only metric used to compare electricity generation technology options. **FOR EXAMPLE,** additional system considerations such as planning and operating reserves, output correlation with nearby plants, and other aspects are included in ReEDS and depend on the overall scenario constraints.
- Standard Scenarios results produced with the ReEDS model do include transmission infrastructure expansion and electric system operation costs.
- This framework should be suitable to inform input assumptions for capacity expansion models such as the National Energy Modeling System (NEMS), MARKAL, and Integrated Planning Model (IPM).
- This framework could be adapted to provide similar comparisons of inputs to other model-based studies such as those using System Advisor Model (SAM), Buildings Industry Transportation Electricity Scenarios (BITES), Cost of Renewable Energy Spreadsheet Tool (CREST), etc.

ATB Methodology for Renewable Electricity Generation Plants

- **Represent cost and performance of typical RE generation plants in the U.S. either by reflecting the entire geographic range of resource with a few points averaging similar characteristics or providing examples to demonstrate range associated with resource potential.**
  - Foundational to this averaging approach, we use high resolution, geography-specific resource data to represent site-specific capital investment and estimated annual energy production for all potential RE plants in the U.S.
- **For each RE technology, present CAPEX, Operations and Maintenance, Capacity Factor and LCOE for all typical RE generation plants**
  - Current year estimates (2013)
  - Three future projections through 2050 representing low, mid, high cost to reflect range of perspectives bounded by published literature
  - Describe resource, cost and performance estimation methodology, data sources and compare with published data
  - Note: Capacity expansion models (including the ReEDS model used by NREL) calculate the optimized capacity factor for each conventionally-fueled plant. The default capacity factors listed in the ATB spreadsheet are meant to be representative, not to reflect exactly what values were used in the modeling.

- **ATB Methodology for Fossil and Nuclear Generation Plants**
  - Rely on EIA representation of current year plant cost estimates, and for plant cost projections through 2040 (AEO 2014)
  - Rely on EIA scenarios for fuel price projections through 2040 (AEO 2014)
  - Hold the EIA plant cost estimates at 2040 levels through 2050.
  - Hold the EIA fuel price projections at 2040 levels through 2050
- **ATB Methodology for Biopower Plants**
  - Rely on EIA representation current year plant cost estimates
  - Rely on EIA representation of future plant cost estimates through 2040 (AEO 2014)
  - Hold the EIA plant cost estimates at 2040 levels through 2050
  - Represent average biopower feedstock price based on “Billion Ton Study” through 2030
  - Hold the biopower feedstock price at 2030 levels through 2050

References

- AEO 2014
- Billion Ton Study

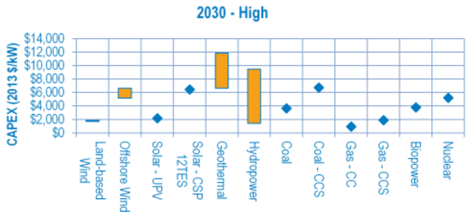
Overview of RE Future Cost Projections

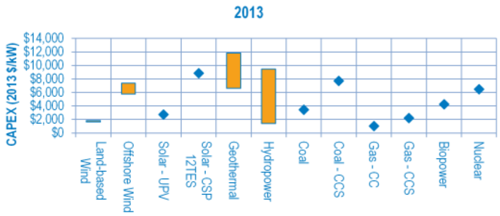
Technology	Source	Rationale
Land-based and Offshore Wind Power Plants	High, low, and median values of population from published studies that include cost projections for scenario modeling	Defining ATB High, Mid and Low cost wind cases as bounding scenarios to published literature provides a range of perspective
Utility-scale Solar PV and Concentrating Solar Power Plants	SunShot Vision study provided basis for long-term projections by phasing year at which near-term SunShot goal is achieved; comparison with published literature established high and low bounds	Defining High, Mid and Low cost PV and CSP cases in relation to detailed near-term analysis (2020) and bounded by published literature provides a range of perspective
Geothermal and Hydropower Plants	Site-specific nature, relative maturity of technology, and lack of existing literature survey lead to assumption of no cost reduction	Geothermal and Hydropower Vision studies which will likely result in industry developed cost reduction scenarios are both currently underway.

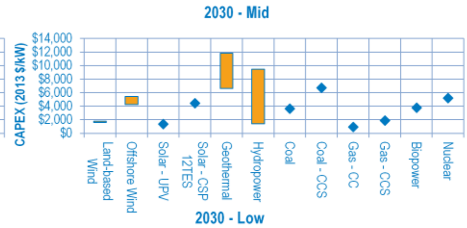
NATIONAL RENEWABLE ENERGY LABORATORY DRAFT VERSION – DO NOT CITE OR DISTRIBUTE 10

- This inaugural version of ATB relies heavily on future cost projections developed for previous studies.
- This framework provides comparison of cost projections with published literature to illustrate potential differences in perspective. In general projections are within bounds of other perspectives represented in published literature.
- Projections developed independently for each technology using different methods, but initial starting point compared with market data (where available) to provide consistent baseline methodology.
- Developing cost and performance projections for electricity generation technologies is very difficult. Methods that rely upon engineering-based models are likely to provide insight into potential technology innovations that yield lower cost of energy. Methods that rely upon learning curves in combination with high-level macro-economic assumptions are likely to provide insight into potential rate of adoption of technology innovations. Both methods have strengths and weaknesses in serving the varied interests that seek these types of projections. Approaches that combine methods are likely to provide the greatest transparency and widest application for technology innovation purposes as well as macro-economic purposes.
- High levels of uncertainty are associated either method. Provision of a range of projections (e.g., low, mid, high) produces scenario modeling results that represent a range of possible outcomes.

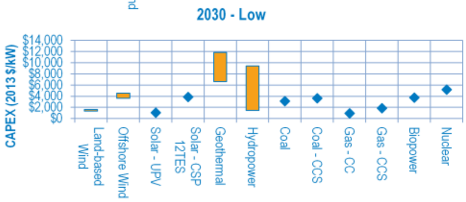
CAPEX Projections Through 2030



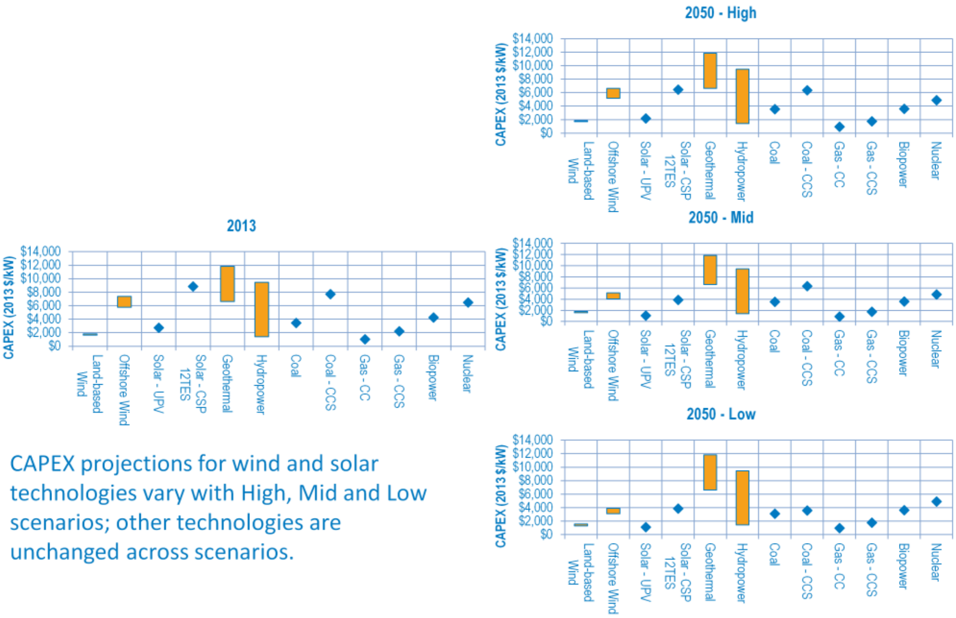




CAPEX projections for wind and solar technologies vary with High, Mid and Low scenarios; other technologies are unchanged across scenarios.

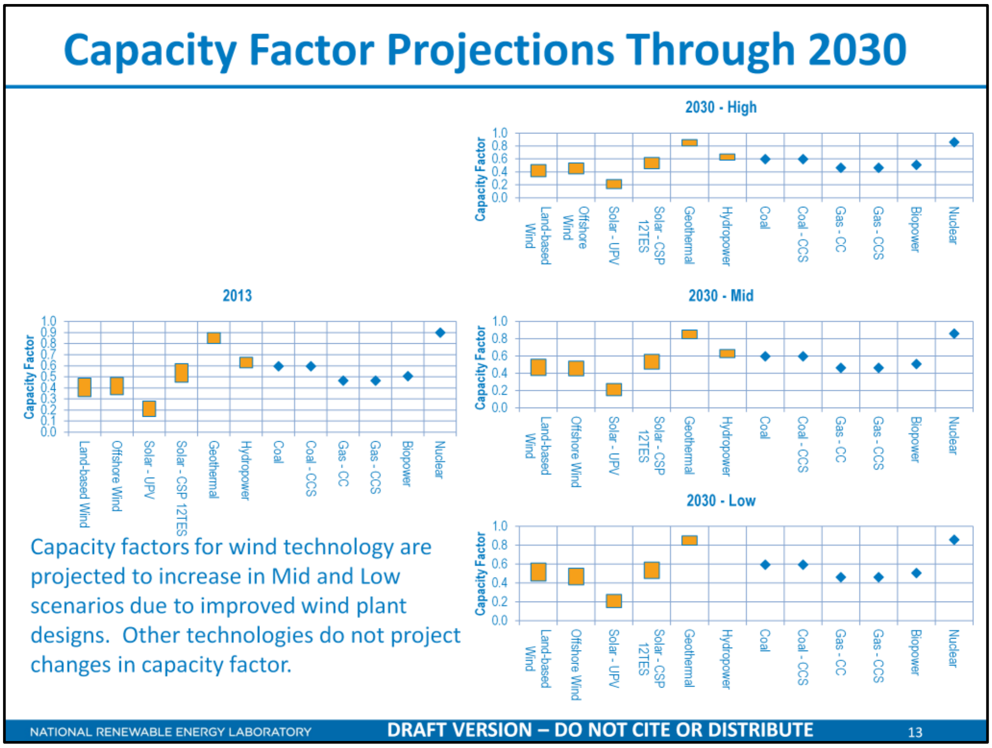


CAPEX Projections Through 2050

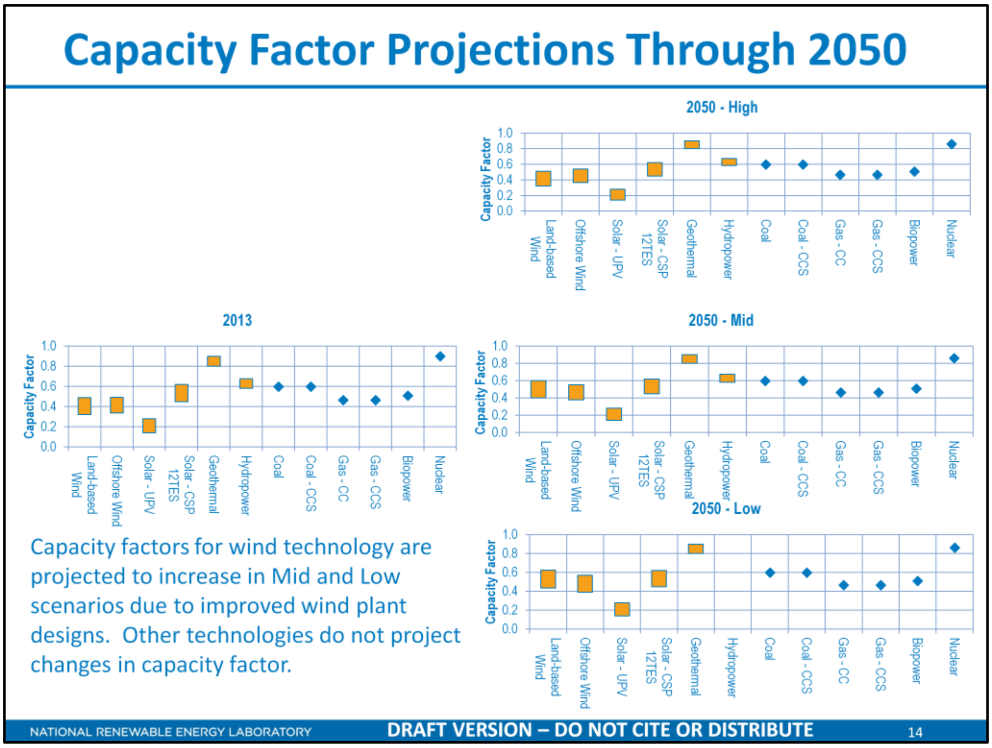


CAPEX projections for wind and solar technologies vary with High, Mid and Low scenarios; other technologies are unchanged across scenarios.

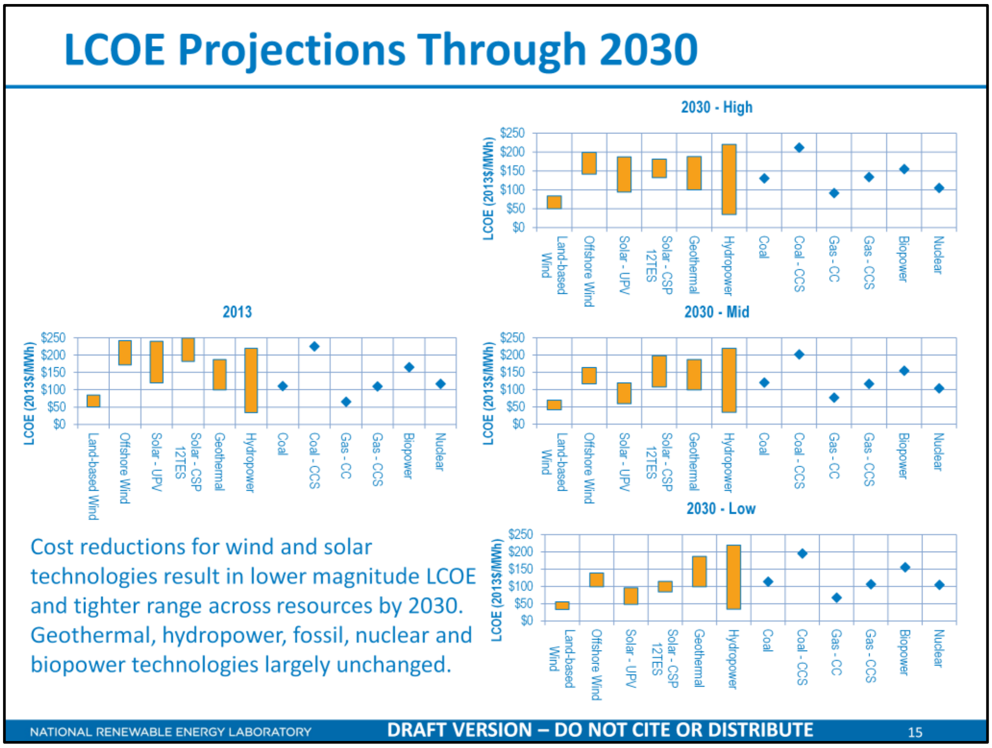
DRAFT VERSION – DO NOT CITE OR DISTRIBUTE



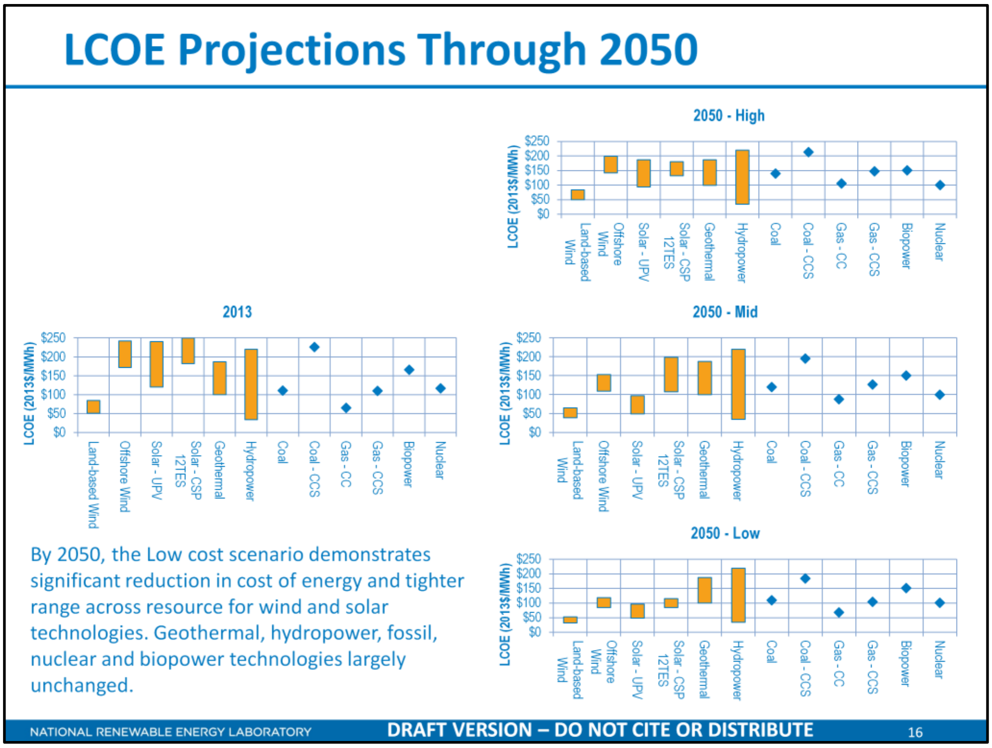
- Note that the capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type. Individual capacity factors for each plant's actual operation will vary significantly, and new investments likely would anticipate higher capacity factors.



- Note that the capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type. Individual capacity factors for each plant's actual operation will vary significantly, and new investments likely would anticipate higher capacity factors.



- Note that the capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type. Individual capacity factors for each plant's actual operation will vary significantly, and new investments likely would anticipate higher capacity factors.



- Note that the capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type. Individual capacity factors for each plant's actual operation will vary significantly, and new investments likely would anticipate higher capacity factors.

Proposed Nomenclature Change for Future Editions

- **Change "Current Year" to "Base Year"**
  - Current Year represents the last full calendar year in which installation data is available. In future iterations this will be called Base Year.
  - A new set of data points will be created for a sub-set of highly dynamic technologies (e.g., Solar PV) to represent cost and/or performance assumptions that are based on part-year data or information; the projections will not be adjusted to accommodate these data points, but they will simply be available to represent mid-year indicators of trends. The next year's version will then establish a new Base Year assumption and adjust projections if needed. This approach allows for a more representative near-term technology characterization for studies that do not require projections through 2050. This approach would also allow representation of project finance assumptions based on real-world experience that may or may not persist in the long term.

LCOE Equation

$$LCOE = \frac{FCR \ast CAPEX + FOM}{CF \times 8760} + VOM + FUEL$$

(terms defined here and on following pages)

- **Assumptions common to all technologies**
  - Generation projects receive similar terms from lenders and equity investors over a 20-year project economic life (WACC = 8.9% nominal/6.2% real)
  - Federal/state blended tax rate does not vary; depreciation schedules vary by technology based on Tax Code
- **Technology-specific assumptions detailed in each subsequent section**
  - Capital Expenditures (CAPEX) represented by total expenditure per kW plant capacity required to achieve commercial operation in a given year
  - O&M represented by average annual fixed (FOM) and variable costs (VOM) over technical life of project
  - Fuel costs applied to some technologies
  - Capacity Factor (CF) used to represent average annual energy production per kW of plant capacity over technical life of project

NATIONAL RENEWABLE ENERGY LABORATORY DRAFT VERSION – DO NOT CITE OR DISTRIBUTE 18

- Variables are defined on Financial Definitions tab in ATB spreadsheet.
- Levelized Cost of Energy (LCOE) selected to represent typical electricity generation cost elements in common framework including project finance (FCR), capital expenditures (CAPEX), fixed and variable operation and maintenance costs (FOM and VOM), and annual energy production/kW plant capacity based on capacity factor (CF) and hours in a year (8760), and fuel costs.
- ATB spreadsheet and accompanying documentation illustrate range of LCOE for electricity generation technologies. Renewable generation technology cost range generally dictated by natural long-term renewable resource characteristics. Fuel-based technology cost range generally dictated by assumed range of future fuel cost.
- Project finance is represented using common assumptions for all technologies in order to focus differences on technical aspect. Depreciation is technology-specific based on IRS tax code. Future ATB modifications to capture actual financing differences between technologies is under consideration.

Summary of Project Finance Terms

$$FCR = CRF \; * ProFinFactor$$

- **Fixed Charge Rate (FCR):** Amount of revenue per dollar of investment required that must be collected annually from customers to pay the carrying charges on that investment.
- **Capital Recovery Factor (CRF):** The ratio of a constant annuity to the present value of receiving that annuity for a given length of time (10.9% nominal / 8.9 % real).
- **Project Finance Factor (ProFinFactor):** Technology-specific financial multiplier to account for any applicable differences in depreciation schedule.

- For long-term scenarios (through 2050) it is assumed that all electricity generation projects receive similar terms from lenders and equity investors. Although perceived level of risk across generation technologies may vary somewhat today, over the period of analysis, it is assumed that all technology options reach a common level of maturity and that there are no systematic differences in risk perception from the finance community. This assumption also focuses the scenario results on changes in the technology cost and performance.
- Future ATB modifications may include the ability to capture actual financing differences between technologies, in the short-term.
- See Excel spreadsheet for equations, variable definitions, and parameters.

Inflation Rate	2.5%
Economic Lifetime (Years)	20
Interest Rate - Nominal	8.0%
Calculated Interest Rate - Real	5.4%
Interest During Construction - Nominal	8.0%
Rate of Return on Equity - Nominal	13.0%
Calculated Rate of Return on Equity - Real	10.2%
Debt Fraction	50.0%
Tax Rate (Federal and State)	40.0%
WACC - Nominal	8.9%
WACC - Real	6.2%
MACRS for Wind (Years)	5
Construction Finance Factor	0.000
Present Value of Depreciation	0.035
Project Finance Factor	1.644
Capital Recovery Factor (CRF) - Nominal	10.9%
Capital Recovery Factor (CRF) - Real	8.9%

Summary of Capital Expenditure (CAPEX) Terms

$$CAPEX = ConFinFactor * (OCC \; * RegCapMult + GCC)$$

- **Construction Finance Factor (ConFinFactor):** Portion of capital expenditure associated with construction period financing. ConFinFactor is a function of construction period duration, interest rate, and expenditure schedule.
- **Overnight Capital Cost (OCC):** Capital expenditures excluding construction period financing. Includes onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation.
- **Capital Regional Multiplier (CapRegMult):** Capital cost multipliers to account for regional variations that affect plant costs, e.g. labor rates. ATB does not represent these regional impacts (CapRegMult = 0), but Standard Scenarios outputs do include regional impacts for some technologies.
- **Grid Connection Costs (GCC):** Spur line costs from the plant gate to the high voltage transmission network based on geographic distance. ATB does not represent distance based grid connections costs (GCC=0) with the exception of offshore wind plants. Standard Scenarios outputs do include site-specific grid connection costs for wind (both land-based and offshore) and solar-CSP plants.

- ATB CAPEX represents typical plant costs and does not represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs. These effects can be represented in the ATB spreadsheet, however, and are represented in Standard Scenario outputs for some technologies.
- Overnight capital costs are based on the plant envelope defined by Beamon and Leff (2013) to include all capital expenditures with the exception of construction-period financing. OCC includes onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation.
- Grid Connection Costs represent distance-based costs of spur lines over land and offshore wind plant export cable costs and construction-period transit costs.
- The ATB technology CAPEX estimates represent general plant capital expenditures and exclude geography specific costs associated with distance to high-voltage transmission line connections or regional cost impacts, e.g., labor rates. These geography specific parameters are applied at various spatial levels within the ReEDS model depending upon the technology. All Standard Scenarios model results include these geography specific parameters that are not represented by the ATB estimates.
- Subsequent notes pages identify differences between what is presented in the ATB slides and additional information that is included in ReEDS Standard Scenarios outputs.

References:

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

ATB Technologies

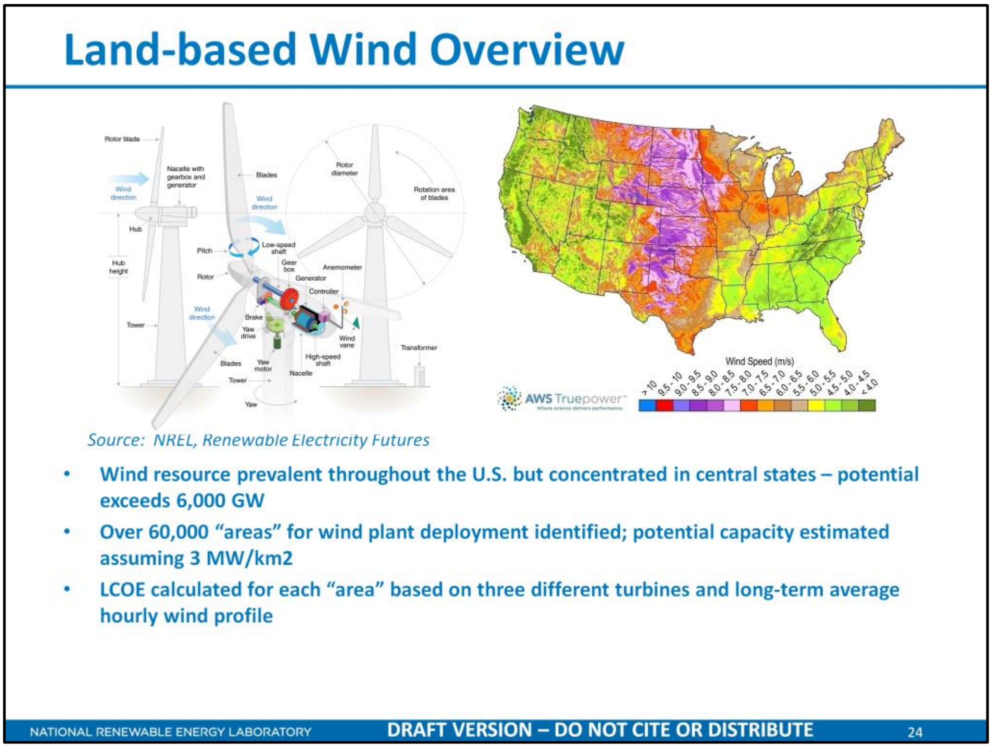
- **Land-based Wind Power Plants**
- **Offshore Wind Power Plants**
- **Utility-Scale Solar PV Power Plants**
- **Concentrating Solar Power Plants**
- **Geothermal Power Plants: Flash and Binary Organic Rankine Cycle**
- **Hydropower Plants: Upgrades to Existing Facilities, Powering Non-Powered Dams, and New Stream-reach Development**
- **Conventional Power Plants: Fossil, Bio, Nuclear**
  - Reference case does not include any carbon costs

Content of Technology Sections

- **Technology Overview**
  - Resource potential and how CAPEX and/or capacity factor vary with resource
  - Methodology for estimating cost and performance over range of resource conditions
- **Plant CAPEX Definition**
  - Listing of items included in CAPEX estimate
- **CAPEX historic trends, current estimates and future projections**
- **Operations and maintenance costs definition and assumptions**
- **Capacity Factor: Expected average energy production over technical lifetime of generation plant historic trends, current estimates and future projections**
- **Cost and performance projections methodology**
- **LCOE projections for low, mid, high cost cases with discussion of technology advances that yield future projections**
- **Data sources and references are identified in Notes pages.**

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Land- based Wind Power Plants



- Wind resource prevalent throughout the U.S. but concentrated in central states – total potential exceeds 6,000 GW (Hand et al., forthcoming) after accounting for exclusions such as federally protected areas, urban areas, water, and others.
- Resource potential represented by over 60,000 "areas" for wind plant deployment; potential capacity estimated assuming 3 MW/km2 to total over 6,000 GW
- CAPEX based on one of three turbine models associated with the annual average wind speed for each "area".
- CF determined using three normalized wind turbine power curves and hourly wind profile for each "area"
- The majority of land-based wind plants installed in the U.S. range from 50 MW to 100 MW (Wiser and Bolinger, 2014).

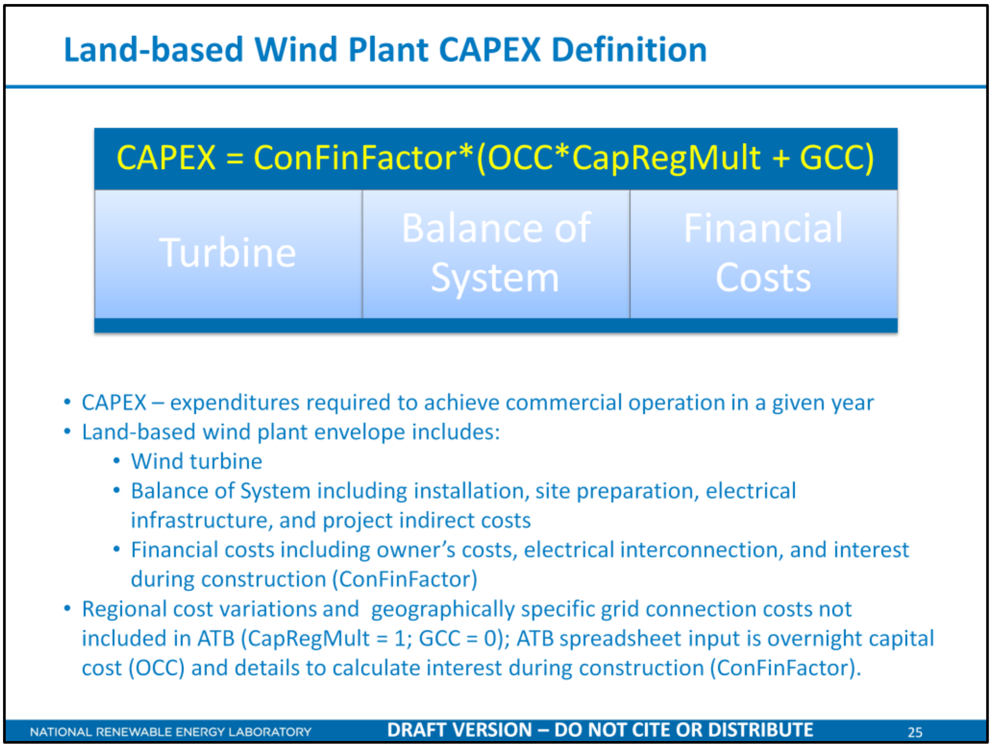
References

Hand,M.; Belyeu, K.; Cohen, S.; Heimiller, D.; Lantz, E.; Mai, T.; Mulcahy, D.; Roberts, O.; Scott, G.; Smith, A.; Wiser, R. (2014). Wind Power Technology Cost and Performance Assumptions. Internal report prepared for DOE sponsored study (forthcoming).

Volume 2: Renewable Electricity Generation and Storage Technologies
Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory.

AWS Truepower. Wind Resource Map. https://www.awstruepower.com/assets/Wind-Resource-Map-UNITED-STATES-11x171.pdf

Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.



- CAPEX in ATB represents wind plant cost in location with no significant logistical challenges or unusual siting conditions similar to the Interior region of the U.S. Regional variants associated with labor rates, material costs, etc. (CapRegMult) are not included.
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following (Beamon and Leff, 2013; Moné et al., 2015):
  - Wind turbine supply
  - Balance of System including
    - turbine installation, substructure supply and installation
    - site preparation, installation of underground utilities, access roads, buildings for operations and maintenance
    - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

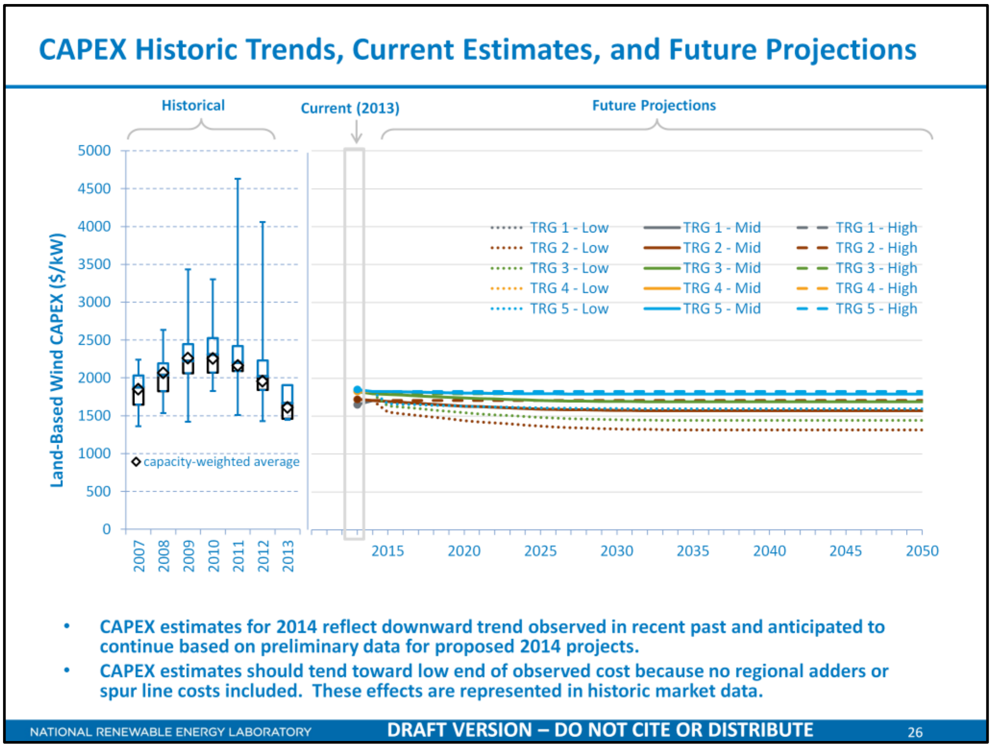
Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (Beamon and Leff, 2013)
- ReEDS determines land-based spur line (GCC) uniquely for each of the 60,000 "areas" based on distance and transmission line cost.

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Moné, C.; Smith, A., Hand, M., Maples, B. (forthcoming). *2013 Cost of Wind Energy Review*.



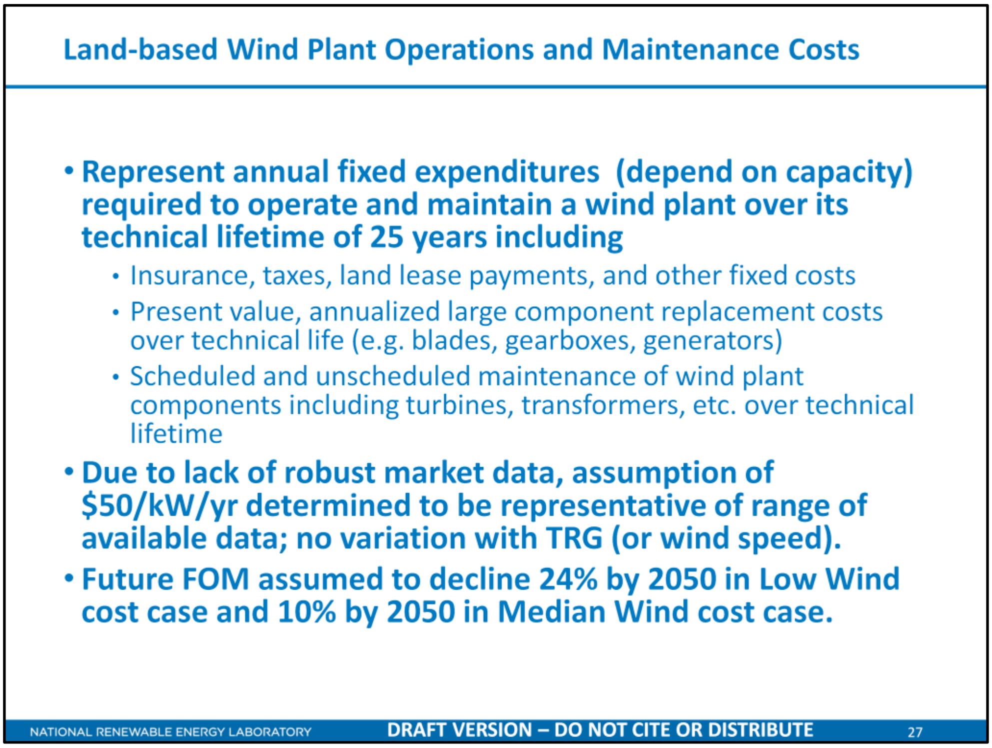
- For illustration in ATB, all potential land-based wind plant "areas" were represented in five bins. The bins were defined based on LCOE range. Capacity weighted average wind speed and resource potential are shown below.

TRG	LCOE Range ($/MWh)	Weighted Average Wind Speed (m/s)	Potential Wind Plant Capacity (GW)	Potential Wind Plant Energy (TWh)
Land 1	<=53	8.9	70	289
Land 2	53-58	8.1	1,171	4705
Land 3	58-68	7.4	2,429	9281
Land 4	68-78	6.7	1,175	3842
Land 5	78<=	6.1	1,323	3674
Total			6,168	21,792

- Actual land-based wind plant CAPEX (Wiser and Bolinger, 2014) is shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections. Wiser & Bolinger (2014) provides statistical representation of CAPEX for about 65% of wind plants installed in the U.S. since 2007
- CAPEX estimates for 2014 reflect downward trend observed in recent past and anticipated to continue based on preliminary data for proposed 2014 projects.
- CAPEX estimates should tend toward the low end of observed cost because no regional impacts or spur line costs are included. These effects are represented in the market data.
- Projections of future wind plant CAPEX were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

References

Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.
Lantz, E.; Wiser, R.; Hand, M. (2012). IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. 137 pp.; NREL Report No. TP-6A20-53510.
Wiser, R.; Lantz, E.; Bolinger, M.; Hand, M. (2012). *Recent Developments in the Levelized Cost of Energy From U.S. Wind Power Projects.* Presentation submitted to IEA Task 26.

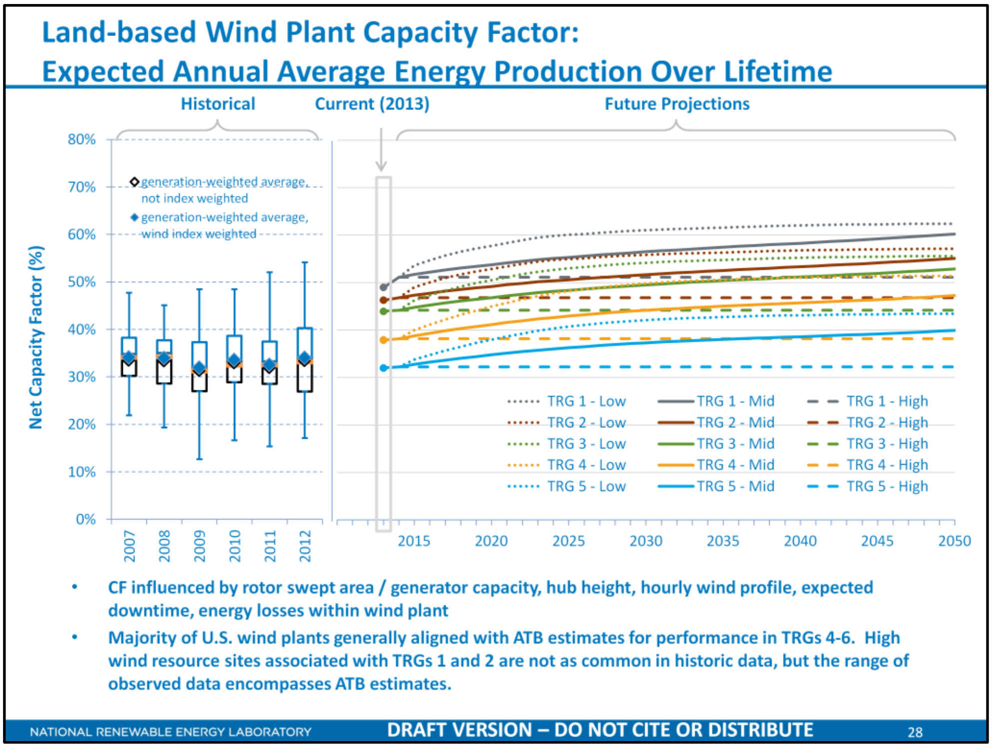


- Represent annual fixed expenditures (depend on capacity) required to operate and maintain a wind plant over its technical lifetime of 25 years including
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component replacement costs over technical life (e.g. blades, gearboxes, generators)
    - Scheduled and unscheduled maintenance of wind plant components including turbines, transformers, etc. over technical lifetime
- Due to lack of robust market data, assumption of $50/kW/yr determined to be representative of range of available data; no variation with TRG (or wind speed).
- Future FOM assumed to decline 24% by 2050 in Low Wind cost case and 10% by 2050 in Median Wind cost case.
- Projections of future wind plant FOM were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

References

Lantz, E. (2013). Operations Expenditures: Historical Trends and Continuing Challenges (Presentation). NREL (National Renewable Energy Laboratory). 20 pp.; NREL Report No. PR-6A20-58606.

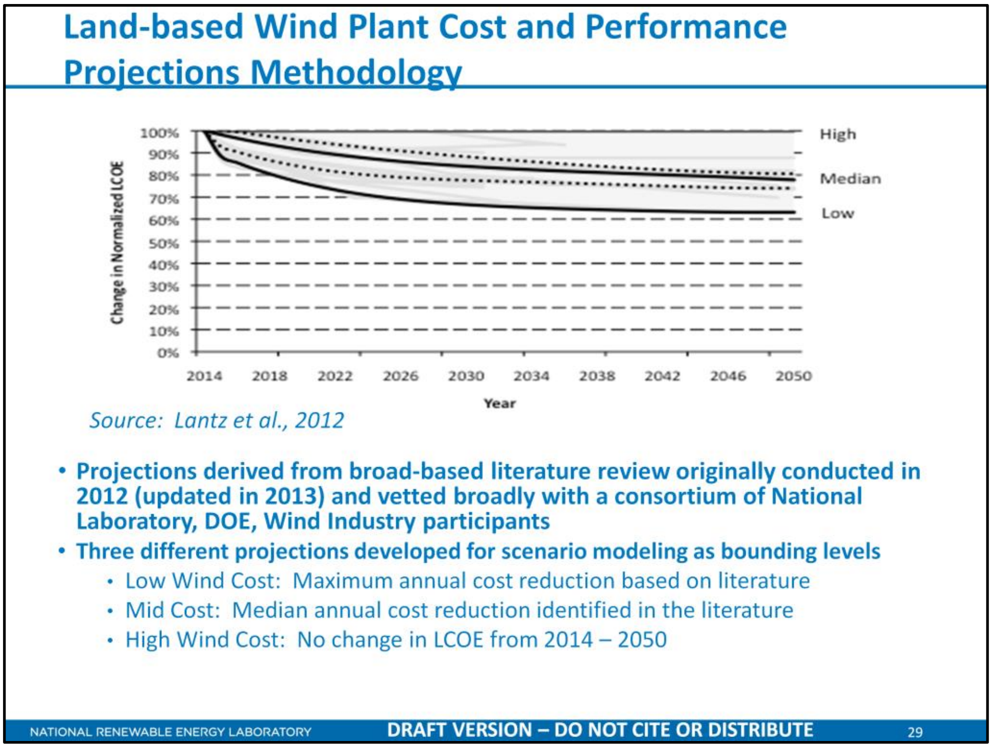
Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.



- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- CF influenced by rotor swept area / generator capacity, hub height, hourly wind profile, expected downtime, energy losses within wind plant
- CF referenced to 80 m above ground level long-term average hourly wind resource data from AWS Truepower
- For illustration in ATB, all potential land-based wind plant “areas” were represented in five bins. The bins were defined based LCOE ranges. Capacity weighted average CAPEX, CF, and resource potential are shown in earlier slide.
- Actual energy production from about 90% of wind plants operating in the U.S. since 2007 (Wiser and Bolinger, 2014) is shown in box and whiskers format for comparison with ATB current estimates and future projections.
- Majority of U.S. wind plants generally aligned with ATB estimates for performance in TRGs 4-6. High wind resource sites associated with TRGs 1 and 2 are not as common in historic data, but the range of observed data encompasses ATB estimates.
- Projections of capacity factor for plants installed in future years were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

Standard Scenarios Model Results
- ReEDS output capacity factors for wind and solar-PV can be lower than input capacity factors due to endogenously estimated curtailments determined by scenario constraints.

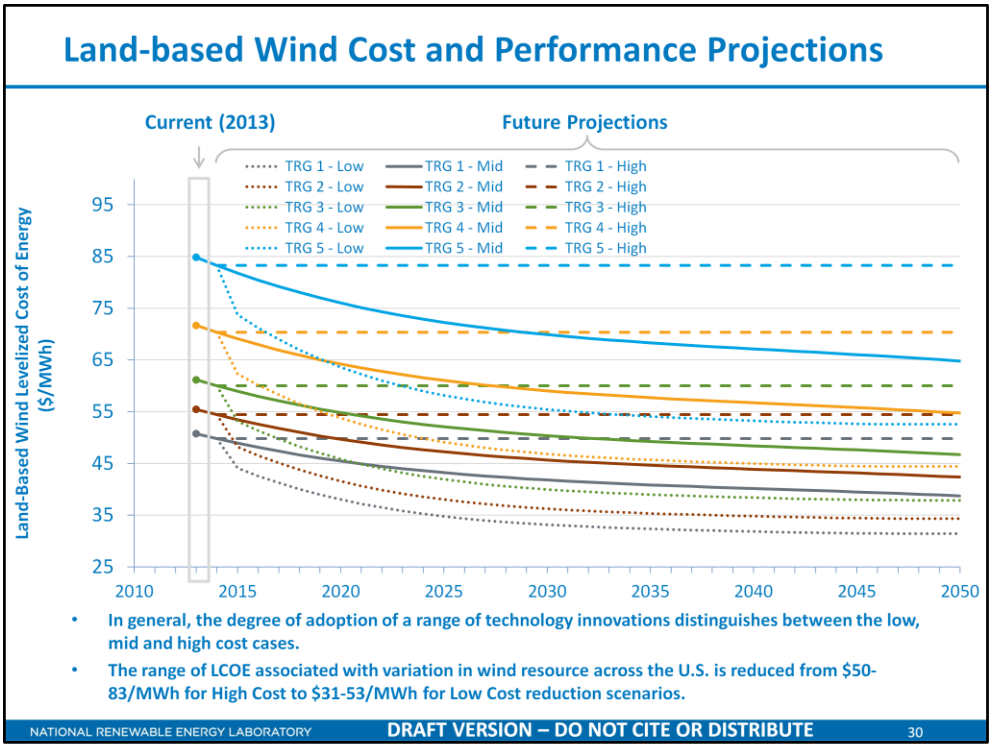
References
Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.
Lantz, E.; Wiser, R.; Hand, M. (2012). IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. 137 pp.; NREL Report No. TP-6A20-53510.
Wiser, R.; Lantz, E.; Bolinger, M.; Hand, M. (2012). *Recent Developments in the Levelized Cost of Energy From U.S. Wind Power Projects.* Presentation submitted to IEA Task 26.



- Projections derived from broad-based literature review and vetted with a consortium of National Laboratory, DOE and wind industry experts.
- Projections derived from analysis of more than 20 different projection scenarios from more than 15 independent published studies.
- Literature estimates normalized to a common starting point in order to focus on projected cost reduction; range of cost reduction 0% - 40% through 2050.
- Three different projections developed for scenario modeling as bounding levels
    - Low Wind Cost: Maximum annual cost reduction based on literature
    - Mid Cost: Median annual cost reduction identified in the literature
    - High Wind Cost: No change in LCOE from 2014 - 2050
- Cost of energy reductions were implemented as changes to CAPEX, CF, and FOM as illustrated on previous slides.

References

Lantz, E.; Wiser, R.; Hand, M. (2012). IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. 137 pp.; NREL Report No. TP-6A20-53510.

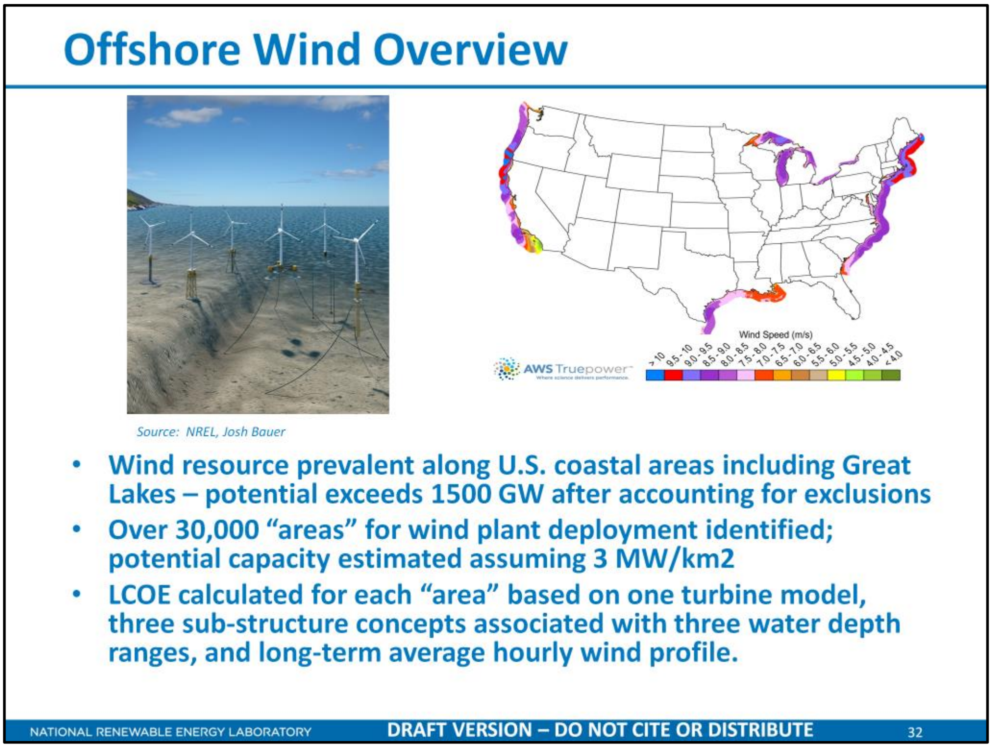


In general, projections represent the following trends, and the degree of adoption distinguishes between Low and Mid Wind Cost scenarios.

- Continued turbine scaling to larger MW turbines with larger rotors such that swept area / MW capacity decreases resulting in high capacity factors for a given location
- Continued diversity of turbine technology where largest rotor diameter turbines tend to be located in lower wind speed sites, but number of turbine options for higher wind speed sites increases.
- Taller towers that result in higher capacity factors for a given site due to wind speed increase with elevation above ground level.
- Improved plant siting and operation to reduce plant level energy losses increasing capacity factor.
- More efficient operation and maintenance procedures combined with more reliable components to reduce annual average FOM costs.
- Continued manufacturing and design efficiencies such that capital cost / kW decreases with larger turbine components.
- Adoption of a wide range of innovative control, design, and material concepts that facilitate the high level trends described above.

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Offshore Wind Power Plants

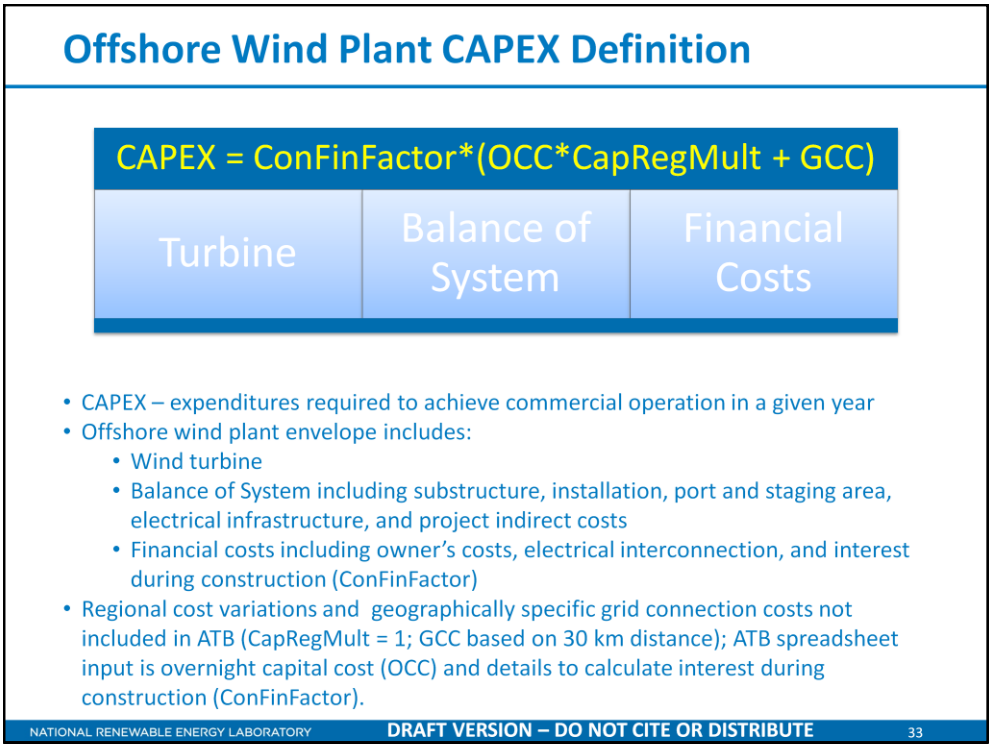


- Wind resource prevalent along U.S. coastal areas including the Great Lakes . Resource potential exceeds 1500 GW (Hand et al., forthcoming) after accounting for exclusions such as marine protected areas, shipping lanes, pipelines, and others.
- Resource potential represented by over 30,000 "areas" for wind plant deployment; potential capacity estimated assuming 3 MW/km2 to total over 15 00 GW.
- CAPEX estimates for each "area" based on one turbine model with three sub-structure concepts associated with three ranges of water depth
- Substructure type reflects water depth
    - Monopile – shallow water from 0-30 m
    - Jacket – mid-depth from 31-60 m
    - Floating – deep water from 61-700 m
- CF estimates determined based on one normalized wind turbine power curve and hourly wind profile for each "area"
- Representative offshore wind plant size is assumed to be about 500 MW (Tegen et al., 2012)

References

Hand, M.; Belyeu, K.; Cohen, S.; Heimiller, D.; Lantz, E.; Mai, T.; Mulcahy, D.; Roberts, O.; Scott, G.; Smith, A.; Wiser, R. (2014). Wind Power Technology Cost and Performance Assumptions. Internal report prepared for DOE sponsored study (forthcoming).

Tegen et al. 2012. Cost of Wind Energy Review



- CAPEX in ATB represents typical offshore wind plant sited 30 km from shore which is representative of currently installed European offshore wind plants. CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs.
- CAPEX for offshore wind plants in ATB include export cable costs and construction-period transit costs associated with a representative distance of 30 km from shore (GCC based on 30 km distance).
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following (Beamon and Leff, 2013; Moné et al., 2015):
  - Wind turbine supply
  - Balance of System including
    - turbine installation, substructure supply and installation
    - site preparation, port and staging area support for delivery, storage, handling, installation of underground utilities
    - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

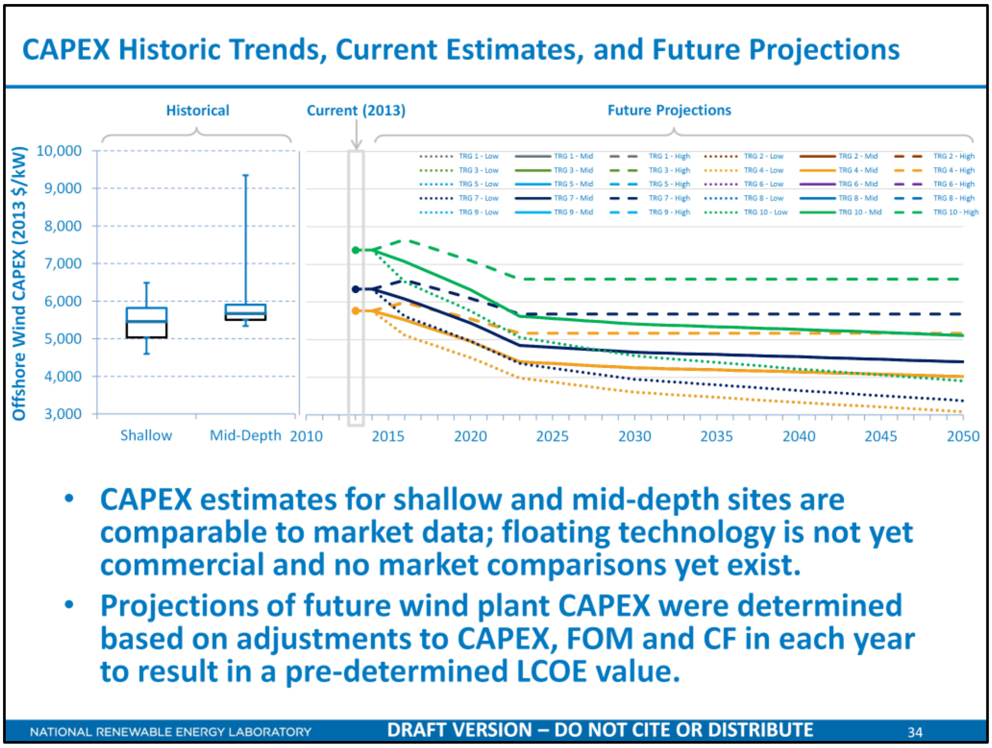
Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (cite SAIC paper).
- ReEDS determines offshore spur line and land-based spur line (GCC) uniquely for each of the 30,000 "areas" based on distance and transmission line cost. ReEDS includes estimates of associated incremental transportation costs during construction with the offshore spur line estimate.

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Moné, C.; Smith, A., Hand, M., Maples, B. (forthcoming). *2013 Cost of Wind Energy Review*



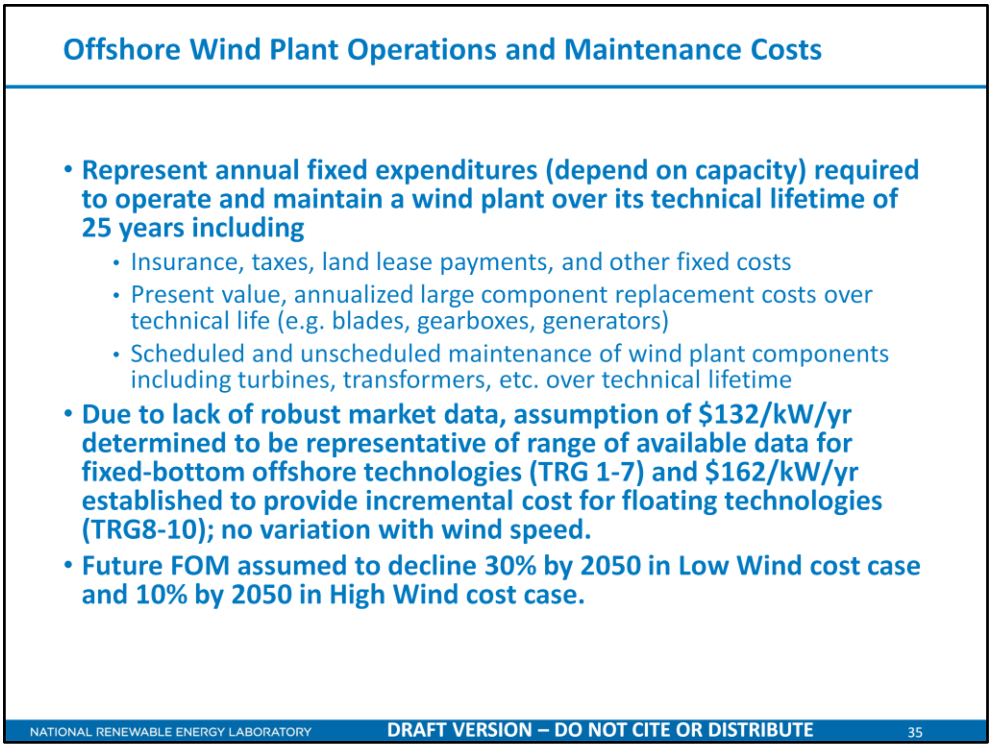
- For illustration in ATB, all potential offshore wind plant “areas” were represented in ten bins. The bins were defined based on water depth and LCOE range. Capacity weighted average wind speed and resource potential are shown below.
- CAPEX in ATB represents offshore cable cost based on 30 km distance to land.

TRG		LCOE Range ($/MWh)	Weighted Average Wind Speed (m/s)	Potential Wind Plant Capacity (GW)	Potential Wind Plant Energy (TWh)
Shallow	OSW 1	LCOE<173	9.1	11	46
	OSW 2	173-193	8.5	61	231
	OSW 3	193-218	8	191	674
	OSW 4	LCOE>218	7.3	165	500
Mid-Depth	OSW 5	LCOE < 208	9.1	48	197
	OSW 6	204-229	8.6	87	338
	OSW 7	LCOE>222	8.4	181	661
Deep	OSW 8	LCOE<248	9.5	82	355
	OSW 9	239-273	9	184	756
	OSW 10	LCOE>259	8.6	549	2078
Total				1,559	5835

- Actual and proposed offshore wind plant CAPEX (Hand et al., forthcoming) are shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections.
- Historical CAPEX data represents European projects > 100 MW installed from 2011 and with expected commissioning dates in 2015. The capacity represented is 3.6 GW installed, 3.7 GW under construction, and 2.1 GW where contracts have been signed with major suppliers.
- CAPEX estimates for shallow and mid-depth “areas” are comparable to market data; floating technology is not yet commercial and no market comparison data exists.
- Projections of future wind plant CAPEX were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

Reference

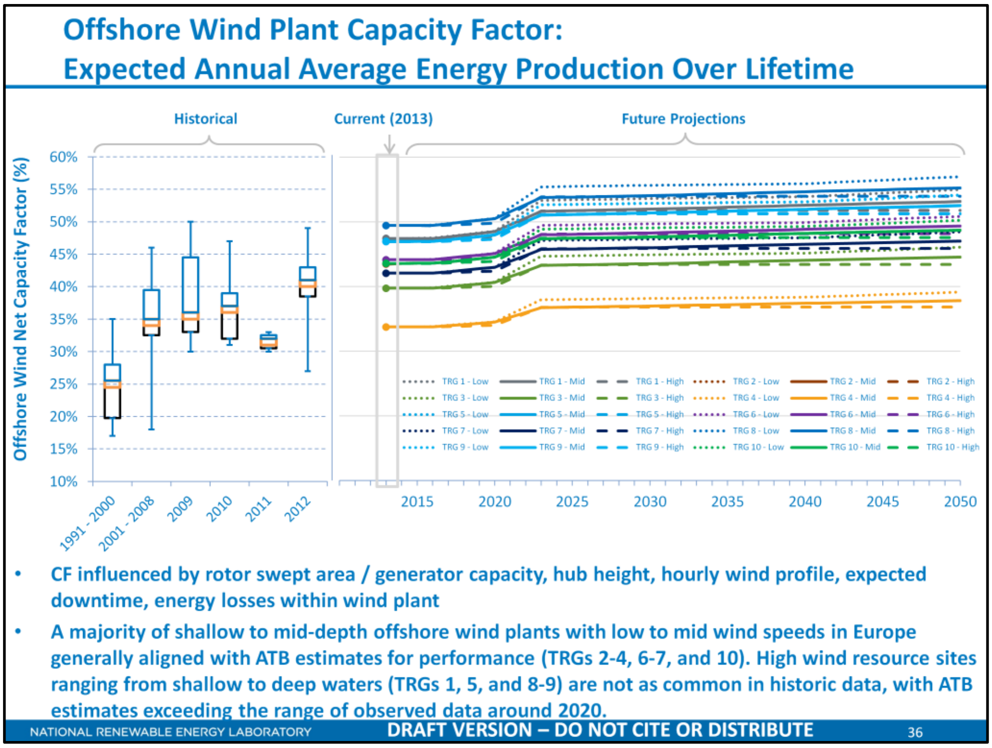
Hand,M.; Belyeu, K.; Cohen, S.; Heimiller, D.; Lantz, E.; Mai, T.; Mulcahy, D.; Roberts, O.; Scott, G.; Smith, A.; Wiser, R. (2014). Wind Power Technology Cost and Performance Assumptions. Internal report prepared for DOE sponsored study (forthcoming).



- Represent annual fixed expenditures (depend on capacity) required to operate and maintain a wind plant over its technical lifetime of 25 years including
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component replacement costs over technical life (e.g. blades, gearboxes, generators)
    - Scheduled and unscheduled maintenance of wind plant components including turbines, transformers, etc. over technical lifetime
- Due to lack of robust market data, assumption of $132/kW/yr determined to be representative of range of available data for fixed-bottom offshore technologies (TRG 1-7) and $162/kW/yr established to provide incremental cost for floating technologies (TRG8-10); no variation with wind speed.
- Future FOM assumed to decline 30% by 2050 in Low Wind cost case and 10% by 2050 in High Wind cost case.
- Projections of future wind plant FOM were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

Reference

Tegen et al. 2012. Cost of Wind Energy Review



- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- CF influenced by rotor swept area / generator capacity, hub height, hourly wind profile, expected downtime, energy losses within wind plant
- CF referenced to 80 m above water surface long-term average hourly wind resource data from AWS Truepower
- For illustration in ATB, all potential offshore wind plant “areas” were represented in ten bins. The bins were defined based on water depth and LCOE ranges. Capacity weighted average CAPEX, CF, and resource potential are shown in earlier slide.
- A majority of shallow to mid-depth offshore wind plants with low to mid wind speeds in Europe are generally aligned with ATB estimates for performance (TRGs 204, 6-7, and 10). High wind resource sites ranging from shallow to deep water (TRGs 1, 5, and 8-9) are not as common in historic data, with ATB estimates exceeding the range of observed data around 2020.
- Projections of capacity factor for plants installed in future years were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

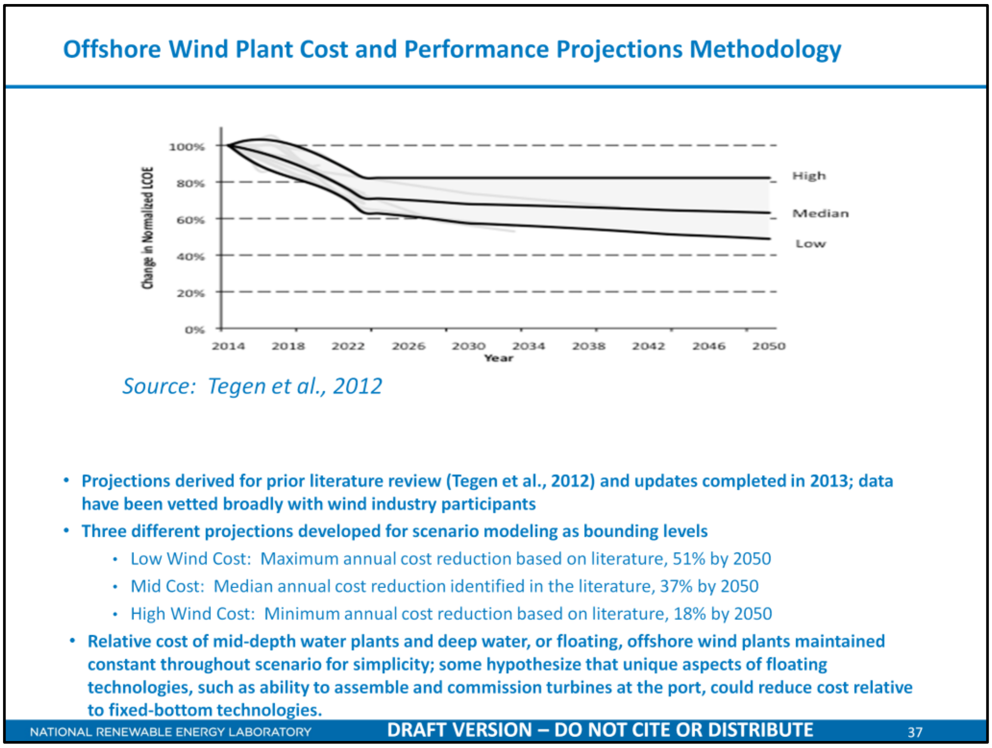
Standard Scenarios Model Results

- ReEDS output capacity factors for wind and solar –PV can be lower than input capacity factors due to endogenously estimated curtailments determined by scenario constraints.

References

Navigant (2013). Offshore Wind Market and Economic Analysis: Annual Market Assessment. Report prepared for the U.S. Department of Energy. http://www1.eere.energy.gov/wind/pdfs/offshore_wind_market_and_economic_analysis.pdf

Hand,M.; Belyeu, K.; Cohen, S.; Heimiller, D.; Lantz, E.; Mai, T.; Mulcahy, D.; Roberts, O.; Scott, G.; Smith, A.; Wiser, R. (2014). Wind Power Technology Cost and Performance Assumptions. Internal report prepared for DOE sponsored study (forthcoming).



- Projections derived from literature review (Tegen et al., 2012) and updated completed in 2013; data have been vetted broadly with wind industry participants.
- Projections derived from analysis of more than 10 different projection scenarios from 6 independent published studies.
    - Fewer published offshore wind cost and performance projections exist, and most do not extend through 2050.
    - Several pathways for cost reduction tied to specific technical advancements identified by BVG Associates for UK Crown Estate (BVG Associates 2012).
- Literature estimates normalized to a common starting point in order to focus on projected cost reduction; range of cost reduction 20-50% through 2050. Due to lack of study projections extending beyond 2030, LCOE reductions post 2030 are loosely based on progress rates of 0% for High Cost and 5% for Mid and Low Cost.
- Relative cost of mid-depth water plants and deep water, or floating, offshore wind plants maintained constant throughout scenario for simplicity; some hypothesize that unique aspects of floating technologies, such as ability to assemble and commission turbines at the port, could reduce cost relative to fixed-bottom technologies.
- Three different projections developed for scenario modeling as bounding levels
    - Low Wind Cost: Maximum annual cost reduction based on literature, 51% by 2050
    - Mid Cost: Median annual cost reduction identified in the literature, 37% by 2050
    - High Wind Cost: Minimum annual cost reduction based on literature, 18% by 2050
- Cost of energy reductions were implemented as changes to CAPEX, CF, and FOM as illustrated on previous slides.

References

BVG Associates. (2012). Offshore Wind Cost Reduction Pathways: Technology Work Stream. http://www.thecrownestate.co.uk/media/5643/ei-bvg-owcrp-technology-workstream.pdf

BVG Associates. (2012). *Offshore Wind Cost Reduction Pathways Technology Work Stream. The Crown Estate*. London. Available at: http://www.thecrownestate.co.uk/media/305086/BVG%20OWCRP%20technology%20work%20stream.pdf

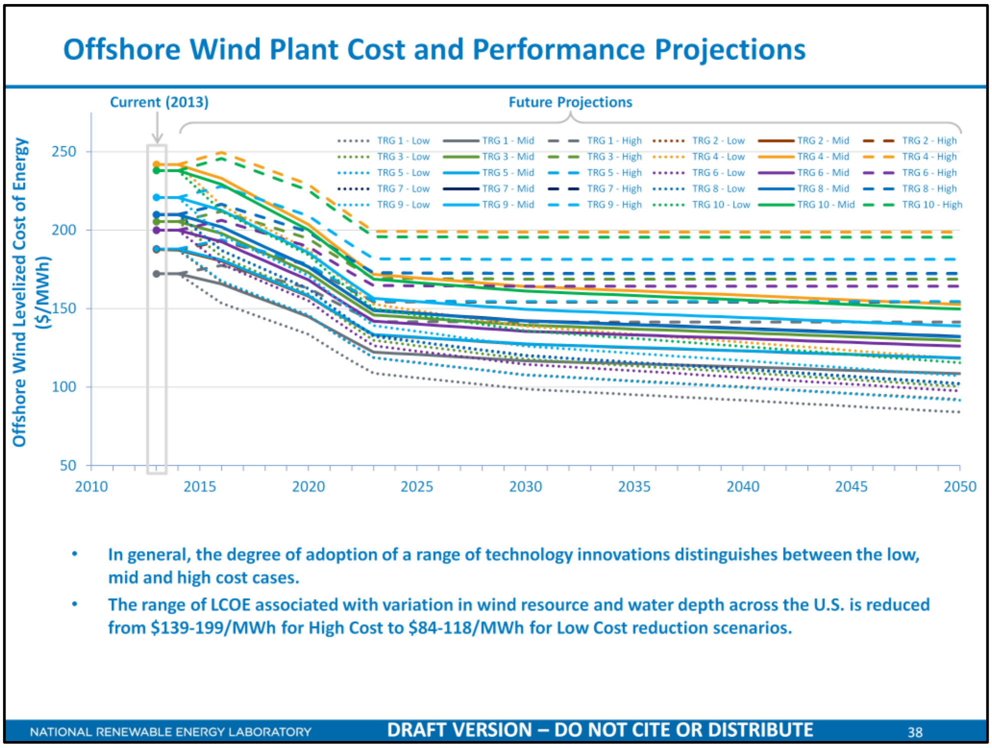
Fischer Prognos Offshore Wind Cost Reductions in Germany (2013)

Bloomberg New Energy Finance 2013

IEA Energy Technology Perspectives 2013

DECC Offshore Wind Round 2 2013

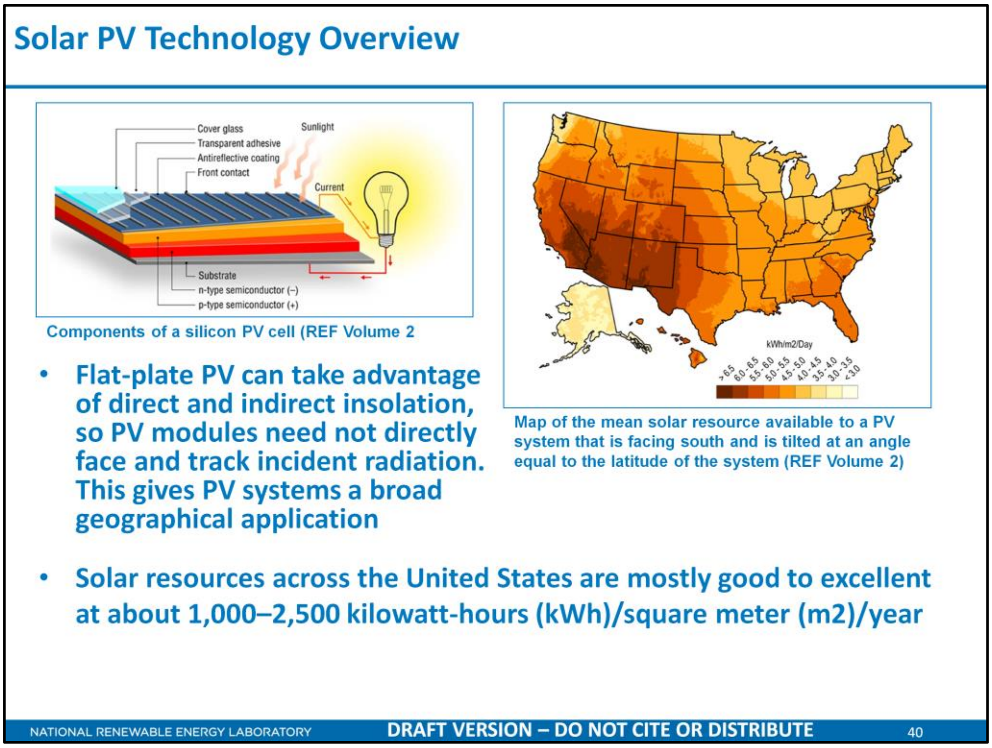
Arup Offshore Wind Round 2



In general, projections represent the following trends, and the degree of adoption distinguishes between Low and Mid and High Wind Cost scenarios.

- Continued turbine scaling to larger MW turbines with larger rotors such that swept area / MW capacity decreases resulting in high capacity factors for a given location
- Greater competition for primary components (e.g., turbines, support structure and installation)
- Economy of scale and productivity improvements including mass-production of sub-structure component and optimized installation strategies.
- Improved plant siting and operation to reduce plant level energy losses increasing capacity factor.
- More efficient operation and maintenance procedures combined with more reliable components to reduce annual average FOM costs.
- Adoption of a wide range of innovative control, design, and material concepts that facilitate the high level trends described above.

Utility-Scale Solar PV Power Plants



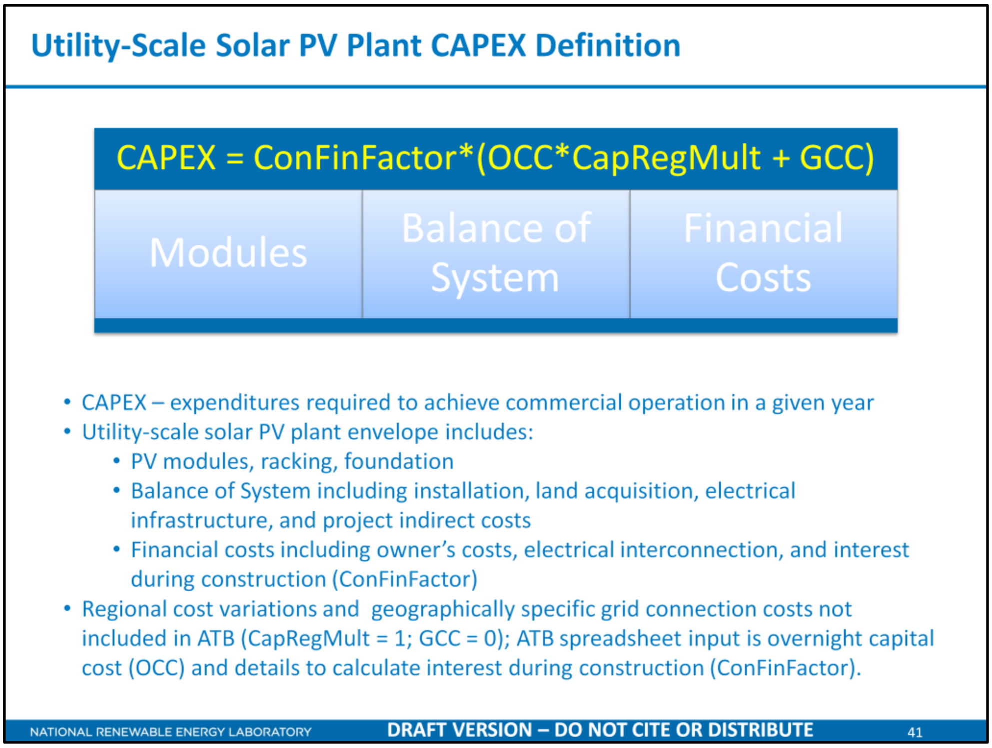
- Solar resources across the United States are mostly good to excellent at about 1,000–2,500 kilowatt-hours (kWh)/square meter (m2)/year. The Southwest is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the 48 contiguous states is about 1,350–2,500 kWh/m2/year. Nationwide, solar resource levels vary by about a factor of two.

- The total U.S. land area suitable for PV is significant and will not limit PV deployment. For example, one estimate suggested that the land area required to supply all end-use electricity in the United States using PV is about 5,500,000 hectares (ha) (13,600,000 acres), which is equivalent to 0.6% of the country’s land area or about 22% of the “urban area” footprint (this calculation is based on deployment/land in all 50 states).
- Utility-scale PV plant cost and performance estimated for all available areas based on typical plant cost and hours of sunlight associated with latitude.
    - CAPEX estimated using manufacturing cost models and benchmarked with industry.
    - CF estimated based on hours of sunlight at latitude.
- Utility-scale PV plants installed in the U.S. are represented by plant size of 10 MW in 2010 growing to 20 MW in 2020 (US DOE, 2012).

References

Volume 2: Renewable Electricity Generation and Storage Technologies. Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O’Neil, S.; Paquette, J.; Tegen, S.; Young, K. (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory.

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927



- CAPEX in ATB represents solar PV plant cost based on modeled system prices representative of bids issued in the fourth quarter of the previous year.
- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines costs.
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following based on NREL Solar-PV Manufacturing Cost Model (Feldman et al.) and (Beamon and Leff, 2013):

    Modules including

        module supply, power electronics, racking, foundation, AC & DC materials and installation.

    Balance of System including

        Land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance.

        Electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center.

        Project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.

    Financial Costs

        Owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction.

        Onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.

        Interest during construction estimated based on 1-year duration accumulated 100% at half-year intervals and 8% interest rate.

            ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction ConFinFactor.

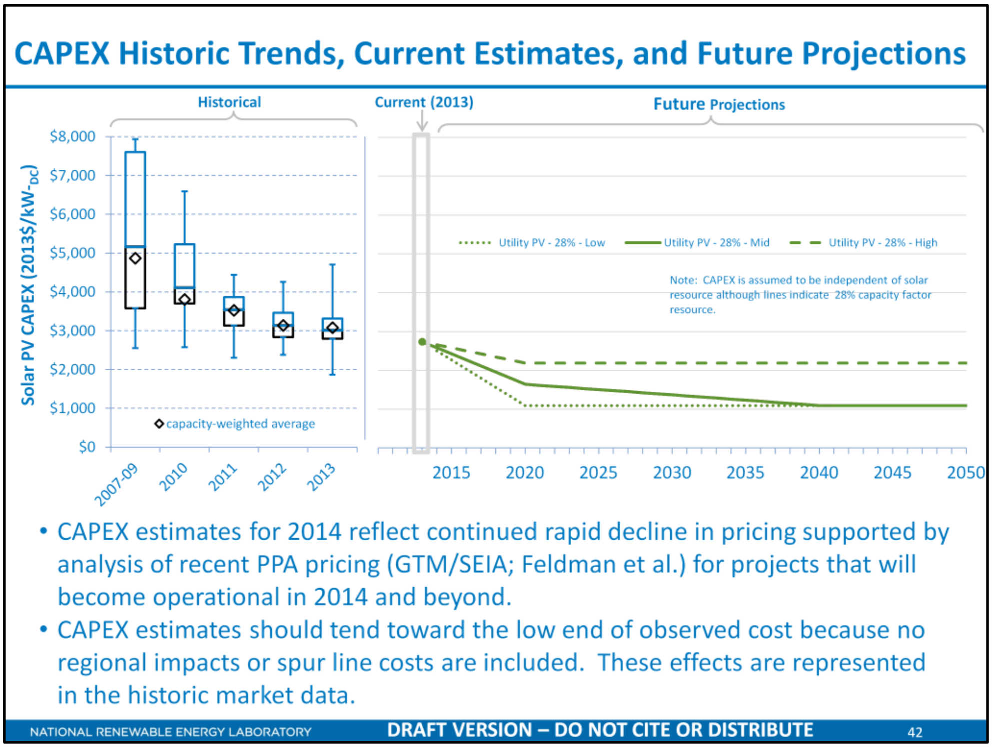
Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (cite SAIC paper).
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, but ReEDS calculates a unique value for each potential PV plant.

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Feldman, D.; Barbose, G.; Margolis, M.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2014 Edition." September 2014. NREL/PR-6A20-62558.



- For illustration in ATB a representative utility-scale PV plant is shown. Although the variety of PV technologies varies, typical plant costs can be represented with a single estimate.
- Although the technology market share may shift over time with new developments, the typical plant cost is represented with the projections above.
- Actual utility-scale PV plant CAPEX (Barbose et al., 2014) is shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections. Barbose et al. (2014) provides statistical representation of CAPEX for 88% of all utility-scale PV capacity and 81% of 2013 capacity additions. Historic CAPEX converted to $\$/kW_{DC}$ by multiplying by 0.83333.
- PV pricing and capacities are quoted in W_{DC} (i.e. module rated capacity) as opposed to other generation technologies which are quoted in W_{AC} (for PV this would correspond to the combined rated capacity of all inverters). This is the unit that the majority of the PV industry uses.
- CAPEX estimates should tend toward the low end of observed cost because no regional impacts or spur line costs are included. These effects are represented in the historical market data.
- Projections of future utility-scale PV plant CAPEX are based on the 50%/62.5%/75% by 2020 cost reduction targets outlined in the SunShot Vision Study. In-between years follow a straight-line schedule to these targets from the assumed $\$2/W_{DC}$ (\$2010) 2014 benchmark which is consistent with pricing reports outlined by NREL and industry benchmarks (GTM/SEIA). Subsequent to 2020, pricing for the high and low cases remains flat, however the mid case reduces to the SunShot Vision Study target by 2040 and then remains flat.

Future ATB Representation Under Consideration

- CAPEX estimates for 2014 reflect continued rapid decline in pricing supported by analysis of recent PPA pricing (GTM/SEIA; Feldman et al.) for projects that will become operational in 2014 and beyond resulting in estimated CAPEX of $\$2,000/kW_{DC}$.

References

Barbose, G.; Darghouth, N.; Weaver, S.; Wiser, R. (2014). *Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013*. Berkeley, CA: Lawrence Berkeley National Laboratory.

GTM Research and Solar Energy Industries Association. (2014). U.S. Solar Market Insight Report. http://www.greentechmedia.com/research/ussmi

Davidson, C.; James, T. L.; Margolis, R.; Fu, R.; Feldman, D. (2014). U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices. 35 pp.; NREL Report No. TP-6A20-62671.

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927
Feldman, D.; Barbose, G.; Margolis, M.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2014 Edition." September 2014. NREL/PR-6A20-62558.

Utility-scale Solar PV Plant Operations and Maintenance Costs

- **Represent annual expenditures required to operate and maintain a solar PV plant over its technical lifetime of 30 years including:**
  - Insurance, legal and administrative fees, and other fixed costs
  - Present value, annualized large component replacement costs over technical life (e.g., inverters)
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime
- **FOM assumed to be $18/kW/yr based on SunShot Vision Study (2012).**
- **Future FOM assumed to decline by 55% by 2021 in Low, Mid and High cost cases.**

NATIONAL RENEWABLE ENERGY LABORATORY DRAFT VERSION – DO NOT CITE OR DISTRIBUTE 43

- Represent annual expenditures required to operate and maintain a solar PV plant over its technical lifetime of 30 years including:
  - Insurance, legal and administrative fees, and other fixed costs.
  - Present value, annualized large component replacement costs over technical life (e.g., inverters).
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime.
- FOM assumed to be \$18/kW_{DC}/yr based on SunShot Vision Study (2012). This number is reasonably consistent with the 2013 "Empirical O&M costs" reported in LBNL's "Utility-scale Solar 2013" technical report, which indicates O&M costs ranging from \$15/kW_{AC}/yr to \$25/kW_{AC}/yr for fixed-tilt PV systems (note: this range would be lower if reported in \$$kW_{DC}$/yr). A wide range in reported price exists in the marketplace, in part depending on what maintenance practices exist for a particular system. These cost categories include: asset management (including compliance and reporting for incentive payments), different insurance products, site security, cleaning, vegetation removal, and failure of components. Not all of these practices are performed for each system; additionally, some factors are dependent on the quality of the parts and construction. NREL analysts estimate that O&M costs can range between \$0 - \$40/kW_{DC}/yr.

2013 O&M estimates	Fixed O&M cost (USD per kW DC)			Variable O&M cost (USD per kWh)
	Min.	Median	Max.	
GTM Survey	8 ~ 12	12 ~ 15	15 ~ 25	0
NREL OpenEI Database	7.56	32.47	110	0
EIA		19.97		0
Lazard		13 ~ 20		0
LBNL	16		32	0

- Future FOM assumed to decline by 55% by 2021 in Low, Mid and High cost cases.
- Current O&M costs are based on those outlined in the SunShot Vision Study, including an inverter replacement in year 15. The low case is based on future O&M costs achieved in the SunShot Vision Study in 2020; the high case assumes no O&M cost reduction; the middle case assumes cost reductions between the high and low case in 2020, with costs reducing to the low case by 2030. There is currently great market variation in what individual companies perform for O&M. Typical projects perform some, but not necessarily all, of the following O&M procedures:

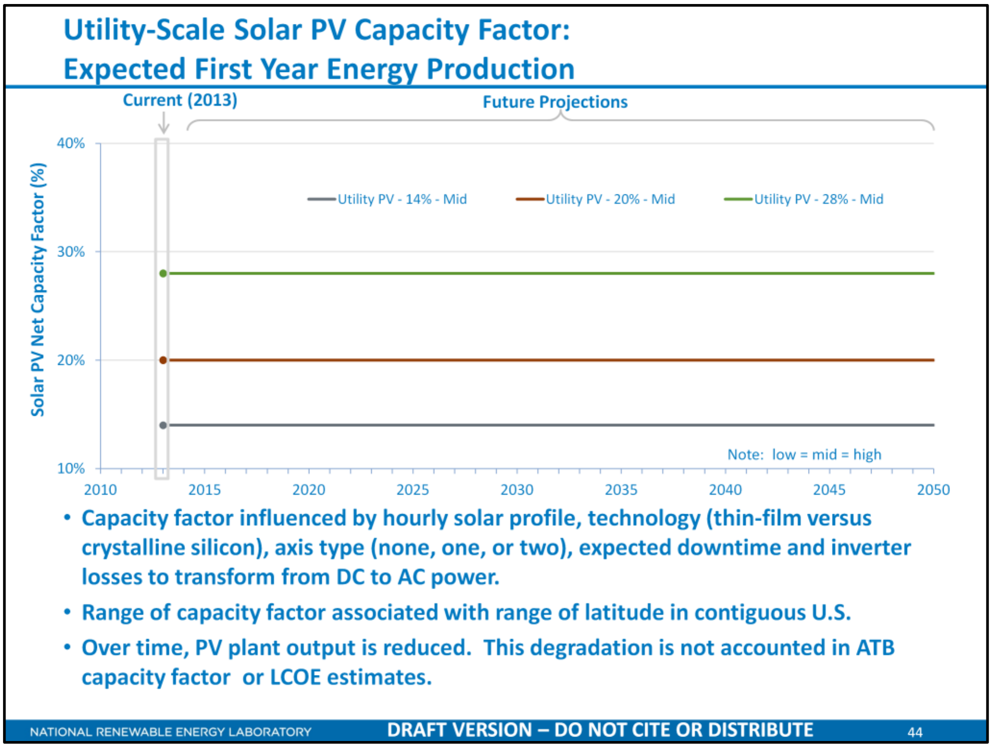
  1) Inverter replacement at 15 years
  2) General maintenance (including cleaning and vegetation removal)
  3) Site security
  3) Legal and administrative fees
  4) Insurance
  5) Property taxes

References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

Bolinger, M. & Weaver, S. *Utility Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*. Lawrence Berkeley National Laboratory. September 2014.

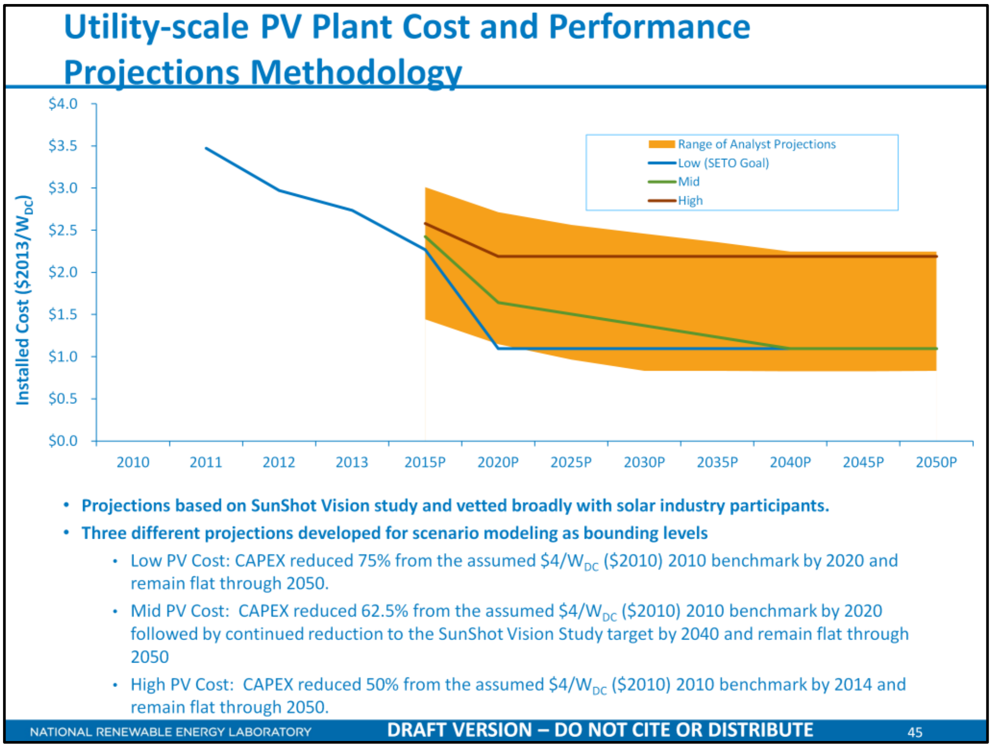
SAIC Energy, Environmental & Infrastructure LLC. "EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Document Report." December 2012.



- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated AC capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant.
- Capacity factor influenced by hourly solar profile, technology (thin-film versus crystalline silicon), axis type (none, one, or two), expected downtime and inverter losses to transform from DC to AC power.
- For illustration in ATB, range of capacity factor associated with range of latitude in contiguous U.S. is shown; capacity factors in the U.S. range from 14% to 28%.
- Over time, PV plant output is reduced. This degradation is not accounted in ATB capacity factor estimates. It is typically represented by a reduced plant capacity in the future rather than a change in annual output.
- Projections of capacity factor for plants installed in future years are unchanged from current year. Solar-PV plants have very little downtime and inverter efficiency is already optimized.

Standard Scenarios Model Results
- Assumed annual degradation of 1% is represented in NPV calculation in ReEDS.
- ReEDS output capacity factors for wind and solar-PV can be lower than input capacity factors due to endogenously estimated curtailments determined by scenario constraints.

References
National Renewable Energy Laboratory. Regional Energy Deployment System (ReEDS).



- Projections based on SunShot Vision study (2012) and vetted broadly with solar industry participants.
- Three different projections developed for scenario modeling as bounding levels
  - Low PV Cost: CAPEX reduced 75% from the assumed $4/W_{DC}$ ($2010) 2010 benchmark by 2020 and remain flat through 2050.
  - Mid PV Cost: CAPEX reduced 62.5% from the assumed $4/W_{DC}$ ($2010) 2010 benchmark by 2020 followed by continued reduction to the SunShot Vision Study target by 2040 and remain flat through 2050
  - High PV Cost: CAPEX reduced 50% from the assumed $4/W_{DC}$ ($2010) 2010 benchmark by 2020 and remain flat through 2050.
- Future pricing is based on the 50%/62.5%/75% 2020 cost reductions targets outlined in the SunShot Vision Study. In-between years follow a straight-line schedule to these targets from the assumed $2/W_{DC}$ ($2010) 2014 benchmark which is consistent with pricing reports outlined by NREL and industry benchmarks (GTM/SEIA). Subsequent to 2020 pricing for the high and low cases remain flat, however the mid cost case reduces to the SunShot Vision Study target by 2040 and then remains flat. The SunShot Vision target is $1/W_{DC}$ ($2010).
- Projections compared to range of available analyst projections from BNEF, EIA, and EREC. Ranges in literature bound projections used in Standard Scenarios Model Results.

Future ATB Representation Under Consideration

- Mid Cost case reduction to reach $1/W may be accelerated to 2030.

References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

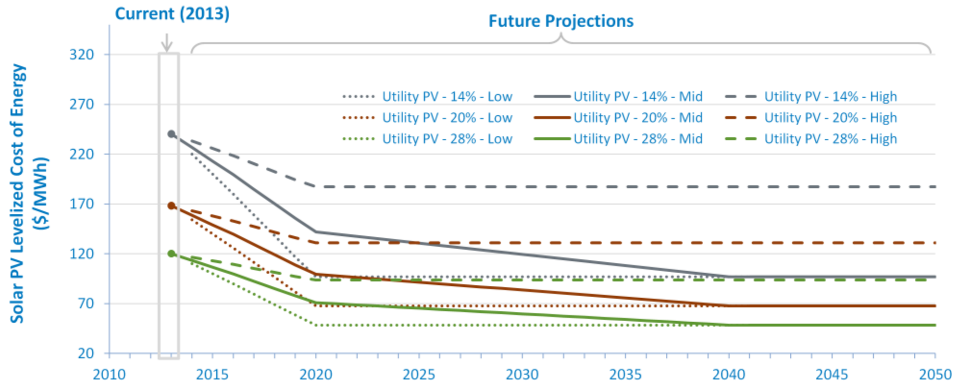
Projections:
Greenpeace/EREC (2014). Energy [R]evolution: A Sustainable USA Energy Outlook. http://www.greenpeace.org/usa/Global/usa/planet3/PDFs/Solutions/Energy-Revolution-2014.pdf (utility-scale only);

International Energy Agency. (2013). World Energy Outlook 2013. http://www.worldenergyoutlook.org/publications/weo-2013/. (New Policy & 450 Scenarios for utility-scale & commercial-scale);

Bloomberg New Energy Finance (2014). Q2 PV Market Outlook.

United States Energy Information Administration (EIA). (2014a). *Annual Energy Outlook 2014 with Projections to 2040*. DOE/EIA-0383(2014). Washington, D.C.: U.S. Department of Energy Office of Integrated and International Energy Analysis. http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf . In years where projection was not made, most recent projection used.

Solar PV Plant Cost and Performance Projections

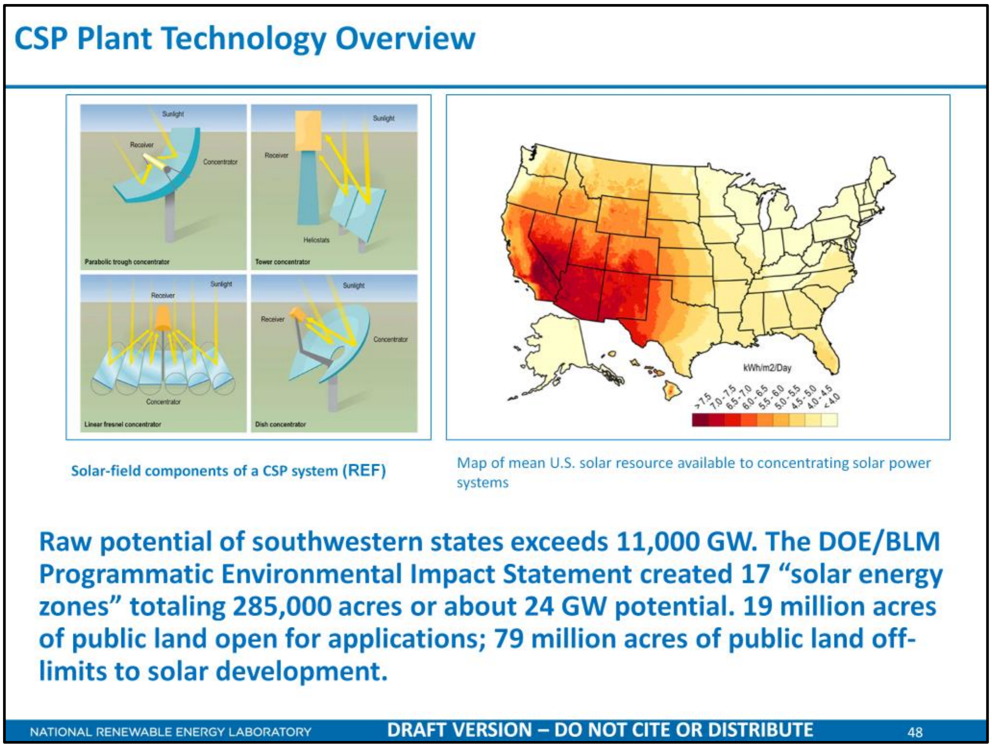


- **In general, the degree of adoption of a range of technology innovations distinguishes between the low, mid and high cost cases.**
- **The range of LCOE associated with variation in solar resource across the U.S. is reduced from $94-187/MWh for High Cost to $48-94/MWh for Low Cost reduction scenarios.**

- In general, projections represent the following trends to reduce CAPEX and FOM. The degree of adoption distinguishes between Low, Mid, and High PV Cost scenarios.
- Modules
  - Increased module efficiencies and increased production-line throughput to decrease CAPEX (overhead costs on a per-kilowatt will go down if efficiency and throughput improvement are realized).
  - Reduced wafer thickness or the thickness of thin-film semiconductor layers.
  - Development of new semiconductor materials.
  - Thin-film (CdTE and CIGS).
  - Developing larger manufacturing facilities in low-cost regions.
- Balance of System
  - Increased module efficiency, reducing the size of the installation.
  - Development of racking systems that enhance energy production or require less robust engineering.
  - Integration of racking or mounting components in modules.
  - Reduction of supply chain complexity and cost.
    - Create standard packages system design.
    - Improve supply chains for BOS components in modules.
    - Create standard packaged system designs.
    - Improve supply chains for BOS components.
  - Improved power electronics
    - Improve inverter prices and performance, possibly by integrating micro-inverters.
  - Decreased installation costs and margins
    - Reduction of supply chain margins (e.g., profit and overhead charged by suppliers, manufacturer, distributors, and retailers); this will likely occur naturally as the U.S. PV industry grows and matures.
    - Streamlining of installation practices through improved workforce development and training, and developing standardized PV hardware.
    - Expansion of access to a range of innovative financing approaches and business models.
    - Development of best practices for permitting interconnection, and PV installation such as subdivision regulations, new construction guidelines, and design requirements.
- FOM cost reduction represents optimized O&M strategies, reduced component replacement costs and lower frequency of component replacement.

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Concentrating Solar Power (CSP) Plants



- Solar resource prevalent throughout the U.S., but the southwest states are particularly suited to CSP plants. The resource potential for seven western states (AZ, CA, CO, NV, NM, UT, and TX) exceeds 11,000 GW assuming an annual average resource > 6.0 kWh/m2/day, and after accounting for exclusions such as land slope (>1%); urban areas; water features; and parks, preserves, and wilderness areas [Mehos, Kabel, and Smithers, 2009].
- The Solar Programmatic Environmental Impact Statement identified 17 solar energy zones (SEZ) in six western states. The 17 SEZs are priority development areas for utility-scale solar energy facilities. These zones total 285,000 acres and are estimated to accommodate up to 24 GW of solar potential. The program also allows development, subject to a more rigorous review, on an additional 19 million acres of public land. Development is prohibited on approx. 79 million acres. [solareis.anl.gov]
- 16 of the 21 currently operating or under-construction CSP plants in the US are parabolic trough technology. Three power tower facilities: Ivanpah (392 MW), Crescent Dunes (110 MW), and Sierra SunTower (5 MW) are on-line or under construction. Two small linear Fresnel plants are in operation. [www.seia.org]
- CAPEX determined using manufacturing cost models and benchmarked with industry data. Reflects dry-cooling technologies to reduce water consumption.
- CF varies with inclusion of thermal energy storage. Typical range 25-50% depending on resource and thermal energy storage amount. Values estimated with SAM.
- Representative CSP plant size is 100 MW in 2010 growing to 200 MW by 2020 (US DOE, 2012).

References

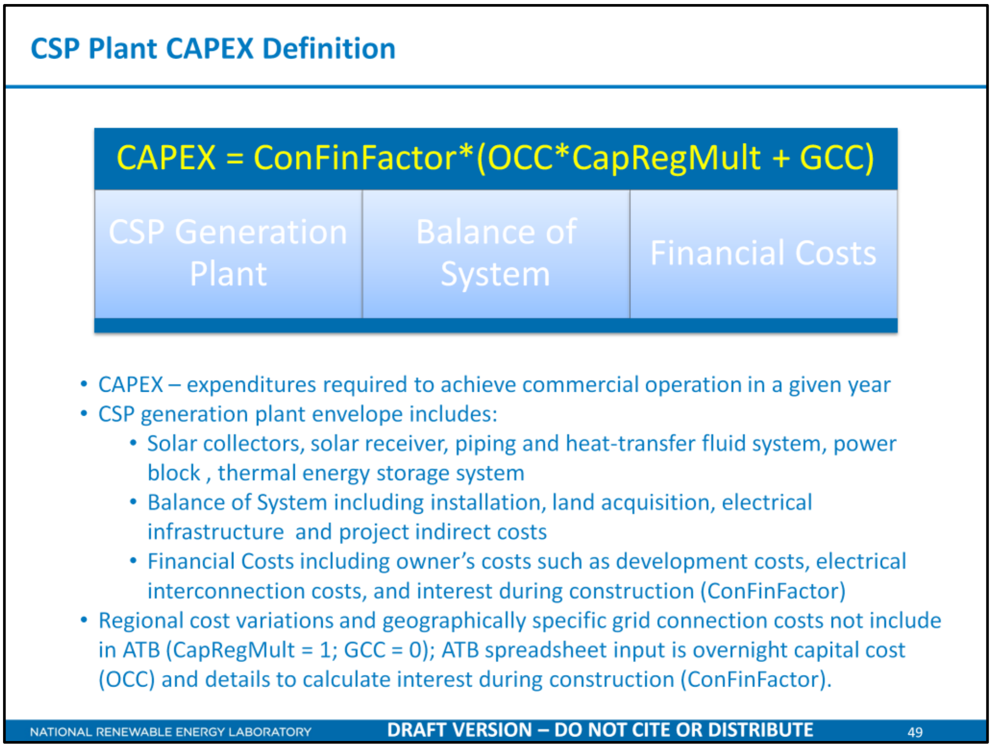
National Renewable Energy Laboratory. (2012). Renewable Electricity Futures Study. Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/.

Mehos, M.; Kabel, D.; Smithers, P. (2009). Planting the Seed: Greening the Grid with Concentrating Solar Power. IEEE Power and Energy Magazine. Vol. 7(3), May/June 2009; pp. 55-62; NREL Report No. JA-550-46134. http://dx.doi.org/10.1109/MPE.2009.932308

Bureau of Land Management and the U.S. Department of Energy. (2012). Final Programmatic Environmental Impact Statement (PEIS) for Solar Energy Development in Six Southwestern States. http://solareis.anl.gov/documents/fpeis/index.cfm.

Solar Energy Industries Association. (2014). Major Solar Projects in the United States: Operating, Under Construction, or Under Development.http://wwwg.seia.org/sites/default/files/resources/PUBLIC%20Major%20Projects%20List%202014-8-19.pdf

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927



- CAPEX in ATB represents solar CSP plant cost based on modeled system prices from industry survey plus indexed costs since last detailed cost study for the fourth quarter of the previous year.
- CAPEX in ATB may not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines costs.
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following based on Beamon and Leff (2013), NREL/TP-550-47605, NREL/TP-5500-57625
  - CSP Generation Plant including
    - installed solar collectors, solar receiver, piping and heat-transfer fluid system, power block (heat exchangers, power turbine, generator, cooling system), thermal energy storage system and installation
  - Balance of System including
    - land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance
    - electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center. The generator voltage is 13.8 kV, the step-up transformer will be 13.8/230kV, the transmission tie line will be 230 kV
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate

      ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results

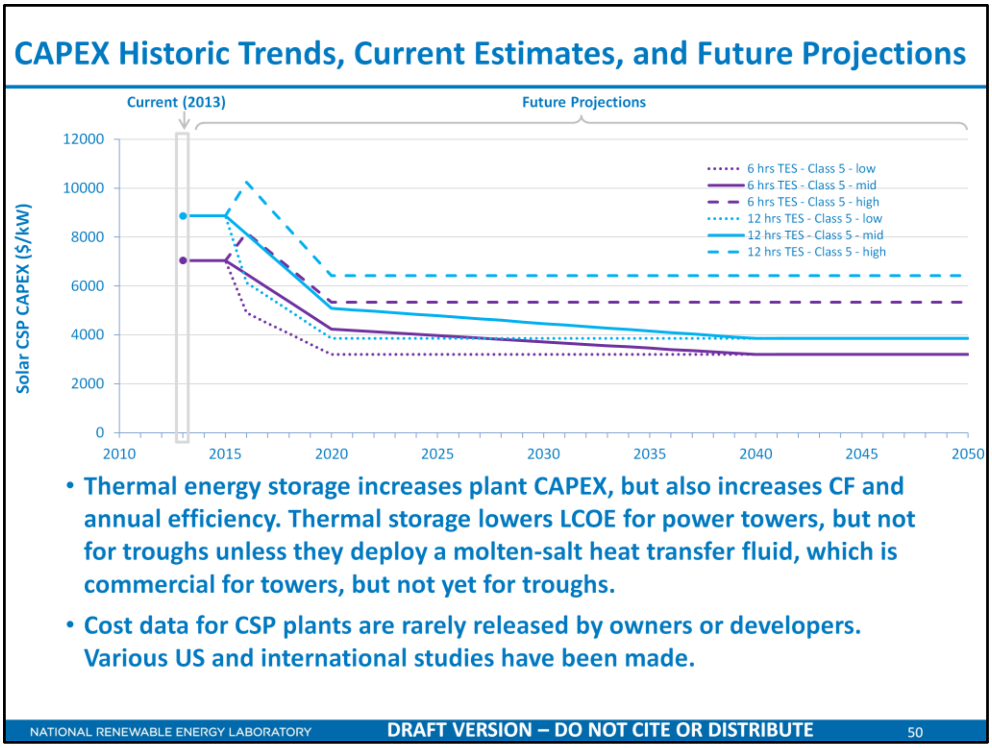
- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (Beamon and Leff, 2013)
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, but ReEDS calculates a unique value for each potential CSP plant

References

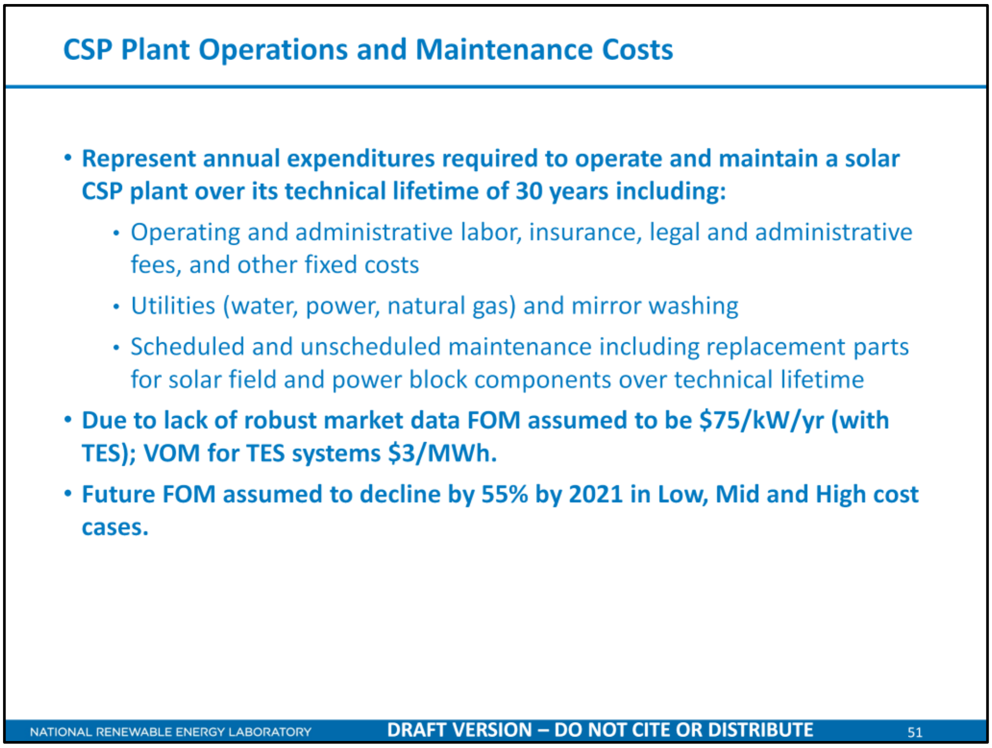
Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Turchi, C. (2010). Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM). 112 pp.; NREL Report No. TP-550-47605.

Turchi, C. S.; Heath, G. A. (2013). Molten Salt Power Tower Cost Model for the System Advisor Model (SAM). 53 pp.; NREL Report No. TP-5500-57625.



- For illustration in ATB two representative CSP plants are shown with differing levels of thermal energy storage (TES): 6 hours, and 12 hours.
- Parabolic trough systems use 1-axis tracking collectors with integrated receiver pipes. Heat-transfer fluid is circulated thru the collector field. Power towers use 2-axis tracking heliostats that focus sunlight onto a central receiver.
- Parabolic trough technology is used to describe CSP systems prior to 2025, after that date, molten-salt power towers are assumed to be the representative technology. Either technology can incorporate thermal energy storage, although power towers do that more efficiently. In both technologies, thermal energy storage is accomplished by storing hot molten salt in a “2-tank” system – a hot-salt tank and a cold-salt tank. Stored, hot salt can be dispatched to the power block as needed, regardless of solar conditions.
- Thermal energy storage increases plant CAPEX, but also increases CF and annual efficiency. Thermal storage lowers LCOE for power towers, but not for troughs unless they deploy a molten-salt heat transfer fluid, which is commercial for towers, but not yet for troughs.
- Cost data for CSP plants are rarely released by owners or developers. Various US and international studies have been made.



- Represent annual expenditures required to operate and maintain a solar CSP plant over its technical lifetime of 30 years including:
  - Operating and administrative labor, insurance, legal and administrative fees, and other fixed costs
  - Utilities (water, power, natural gas) and mirror washing
  - Scheduled and unscheduled maintenance including replacement parts for solar field and power block components over technical lifetime
- Due to lack of robust market data FOM assumed to be $75/kW/yr (with TES); VOM for TES systems $3/MWh. This number is reasonably consistent with the “Empirical O&M costs” reported in LBNL’s “Utility-scale Solar 2013” technical report, which indicates O&M costs ranging from $40/kW/yr to $65/kW/yr for a CSP plant without storage.
- Future FOM assumed to decline by 55% by 2021 in Low, Mid and High cost cases.

References

Bolinger, M. & Weaver, S. *Utility Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*. Lawrence Berkeley National Laboratory. September 2014.

Turchi, C. (2010). Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM). 112 pp.; NREL Report No. TP-550-47605.

Turchi, C. S.; Heath, G. A. (2013). Molten Salt Power Tower Cost Model for the System Advisor Model (SAM). 53 pp.; NREL Report No. TP-5500-57625.

CSP Plant Capacity Factor: Expected Annual Average Energy Production Over Lifetime

		Resource Class		
		Class 1	Class 3	Class 5
Storage	6 hrs. storage	28%	37%	38%
	12 hrs. storage	45%	59%	62%

- **CSP plant capacity factors are influenced by technology (trough versus tower), storage technology and capacity, hourly solar profile, expected downtime, and energy losses**
- **CSP technology assumed to be oil-HTF troughs with indirect TES, switching to molten-salt power towers with direct TES in 2025.**
- **Capacity factors based on modeled performance using SAM.**
- **Projections of CF for plants installed in future years are unchanged from current year.**

- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- Capacity factor influenced by the technology, storage technology and capacity, expected downtime and the solar resource. Two CSP technologies are used in the ATB: (1) an oil-HTF, parabolic trough plant with indirect, 2-tank molten-salt TES, and (2) molten-salt power tower with direct, 2-tank, molten-salt TES. The latter is more flexible, more efficient, and lower LCOE. Either technology can also be modeled without TES.
- For illustration in ATB, range of capacity factor associated with range across the continental U.S. as represented in ReEDS for two classes of solar insolation.
- These CF estimates represent typical operation; the dispatch characteristics of these systems are valuable to the electric system to manage changes in net electricity demand. Actual capacity factors will be influenced by the degree to which system operators call on solar-CSP plants to manage grid services.
- Projections of CF for plants installed in future years are unchanged from current year. Direct, 2-tank TES is approx. 98% efficient and is used for current and future TES and CF estimates. Cost reduction efforts focused on CAPEX, and dispatch characteristics of storage systems ultimately dictate capacity factor.
- CSP plant performance is modeled in SAM. Plant data are rarely public, and large-scale CSP with storage has relatively low historic data. IRENA reports Spanish parabolic trough plants with 7.5 hours TES having a CF=40% and Gemasolar (20 MW molten-salt power tower, 15 hours of TES) with CF=74%. [IRENA-ETSAP CSP Techbrief E10 Jan., 2013].

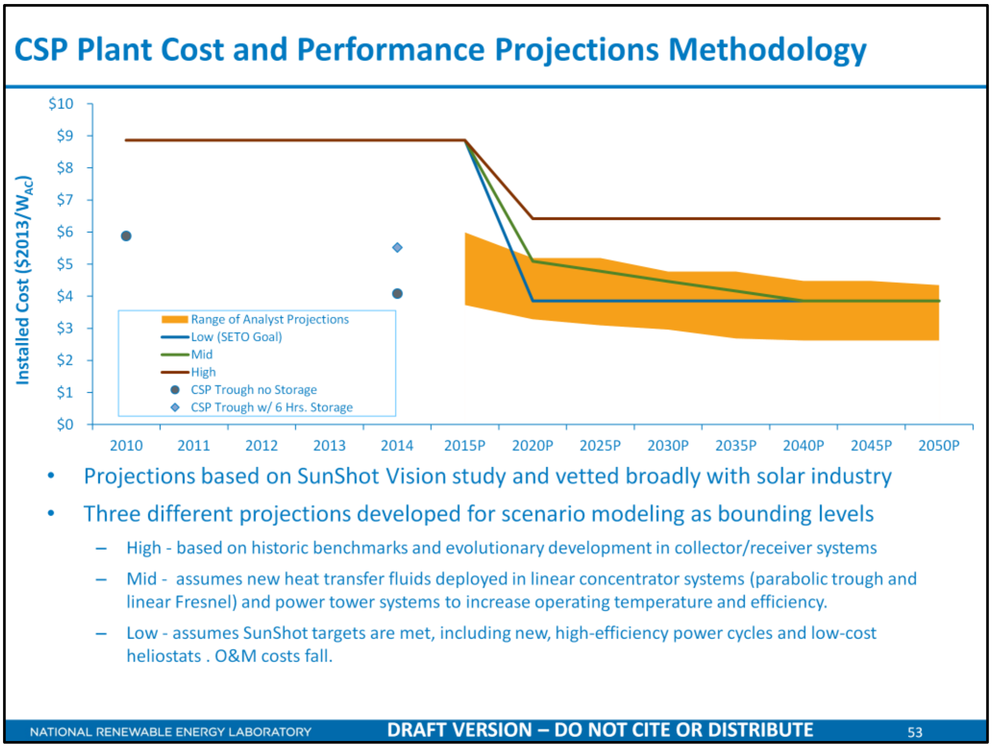
Standard Scenarios Model Results

- CSP plants with thermal storage can be dispatched by grid operators to accommodate diurnal and seasonal load variations and output from variable generation sources (wind and solar-PV). Because of this, their annual energy production and the value of that generation is determined by the electric system needs and capacity and ancillary services markets.

References

Turchi et al., "Current and Future Costs for Parabolic Trough and Power Tower Systems in the US Market," 2010.

International Energy Agency and International Renewable Energy Agency. (2013). Concentrating Solar Power: Technology Brief. http://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20E10%20Concentrating%20Solar%20Power.pdf



- Projections based on SunShot Vision study and vetted with solar industry participants.
- Three different projections developed for scenario modeling as bounding levels
    - High: evolutionary changes in trough designs; deployment of direct-steam generation troughs and power towers. Molten-salt power towers deployed and gain operating experience. Larger systems and clustered “power parks” decrease project development and operating costs.
    - Mid (above plus): Molten-salt HTFs for trough plants. New fluids increase operating temperatures and reduce TES cost for power towers. Greater deployment volume reduces heliostat costs. Thermocline TES systems.
    - Low (above plus): new power cycles developed and deployed. Heliostat design and manufacturing optimization lower heliostat costs. Phase-change TES and modular power towers reduce fabrication and construction costs.
    - Pricing for “CSP Trough” and “CSP Trough w/ 6 Hrs. Storage” derived from cost bases in the publicly released “Section 1603 Payments;” thus reported costs do not include any costs ineligible to receive 1603 grant funds. http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx

References

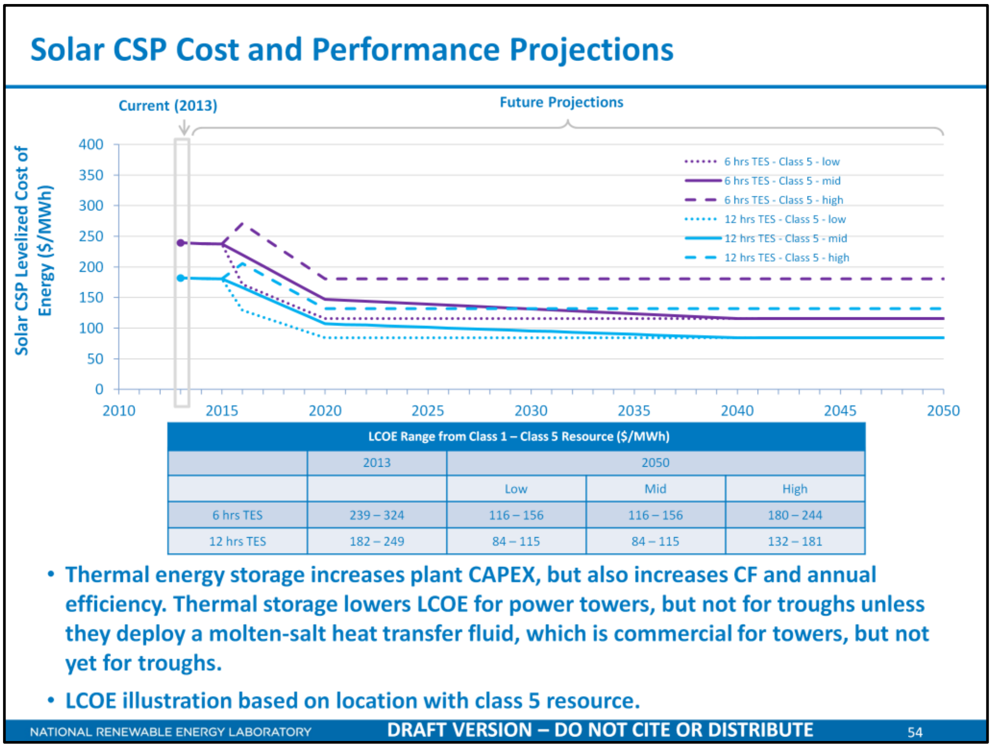
US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

Sandia National Laboratory. (2011). Power Tower Technology Roadmap. SAND2011-2419.

International Renewable Energy Agency. (2012). Renewable Energy Technologies: Cost Analysis Series, Concentrating Solar Power. http://costing.irena.org/media/2794/re_technologies_cost_analysis-csp.pdf

Lazard. (2014). Lazard’s Levelized Cost of Energy Analysis – Version 8.0.

http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf



	2013	2050		
		Low	Mid	High
6 hrs TES	239 – 324	116 – 156	116 – 156	180 – 244
12 hrs TES	182 – 249	84 – 115	84 – 115	132 – 181

In general, projections represent the following trends, and the degree of adoption distinguishes between Low, Mid and High CSP Cost scenarios as described on previous slide.

Trough improvements:
- Lower cost collectors and receivers due to increased deployment and additional manufacturing competition
- Salt HTF in troughs allows for higher operating temperatures and greater efficiencies in the powerblock and TES systems. The HTF is cheaper; piping and insulation volumes drop.

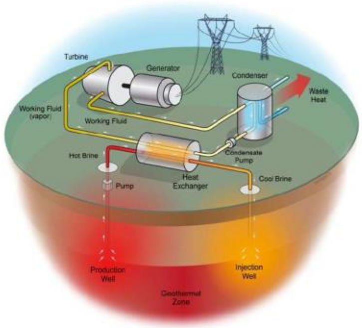
Power Tower improvements:
- Better and longer-lasting selective surface coatings improve receiver efficiency and reduce O&M costs
- New salts allow for higher operating temperatures and lower cost TES
- Development of the supercritical CO2 power cycle improves cycle efficiency, reduces powerblock cost, and reduces O&M costs
- Lower cost heliostats developed due to more efficient designs, and automated and high-volume manufacturing

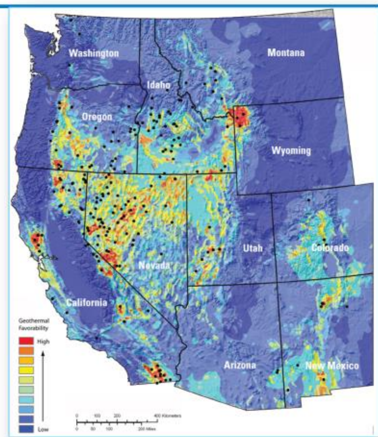
General and “soft” costs improvements:
- Modular plant designs decrease installation costs and margins
- Expansion of world market leads to greater and more efficient supply chains; reduction of supply chain margins (e.g., profit and overhead charged by suppliers, manufacturer, distributors, and retailers)
- Expansion of access to a range of innovative financing approaches and business models
- Development of best practices for permitting interconnection, and installation such as subdivision regulations, new construction guidelines, and design requirements

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Geothermal Power Plants: Flash and Binary Organic Rankine Cycle

Geothermal Technology Overview - Hydrothermal





Source: Williams et al. (2008). USGS, "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States," http://pubs.usgs.gov/2008/3082.

- **Hydrothermal Resource Potential**
  - Identified – 7,833 MW
  - Undiscovered – 37,537 MW
- **Development Costs – Calculated using "Geothermal Electricity Evaluation Model" (GETEM)**

NATIONAL RENEWABLE ENERGY LABORATORY **DRAFT VERSION – DO NOT CITE OR DISTRIBUTE** 56

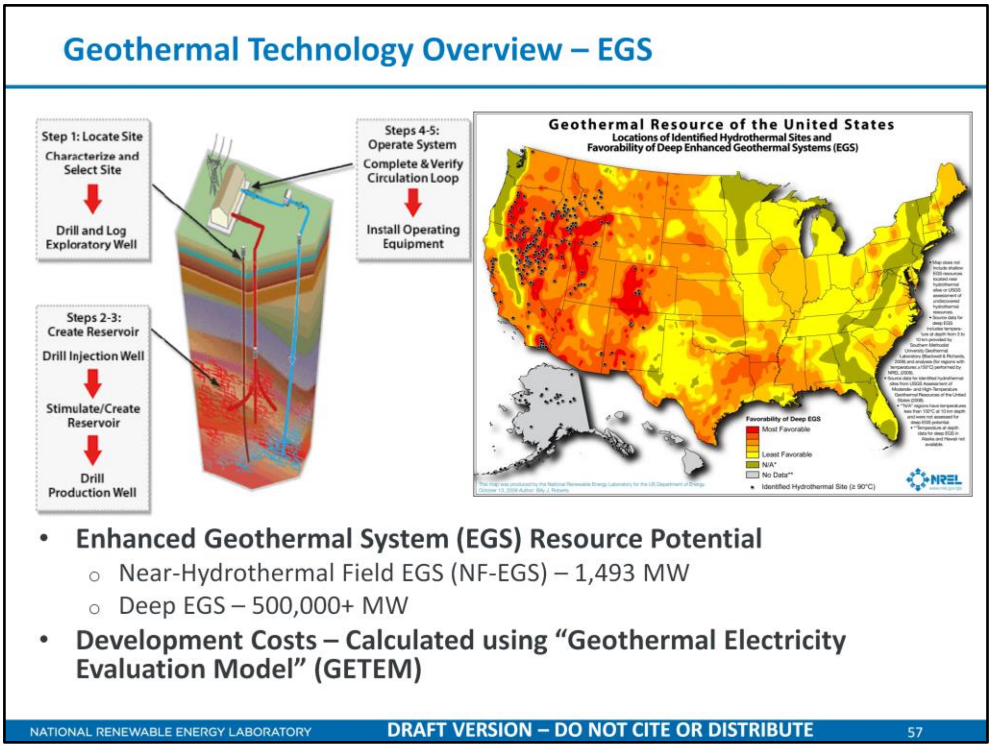
- Hydrothermal geothermal resource concentrated in Western US – total potential is 45,370 GW
- Identified Hydrothermal from USGS 2008 Updated Geothermal Resource Assessment
  - Resource potential estimate at each site identified by USGS based on available reservoir thermal energy information from studies conducted at the site.
  - Installed capacity of about 3 GW in 2014 excluded from resource potential
  - Resource potential estimates increased 20-30% to reflect impact of in-field EGS technologies to increase productivity of dry wells and increase recovery of heat in place from hydrothermal reservoirs.
- Undiscovered hydrothermal values from USGS 2008 Updated Geothermal Resource Assessment
  - Resource potential estimated based on a series of GIS statistical models for the spatial correlation of geological factors that facilitate the formation of geothermal systems.
  - Resource potential estimates increased 20-30% to reflect impact of in-field EGS technologies to increase productivity of dry wells and increase recovery of heat in place from hydrothermal reservoirs.

- Hydrothermal generation plant cost and performance estimated for each potential site using GETEM, a bottom-up cost analysis tool that accounts for each phase of development of a geothermal plant. Model results based on resource attributes (estimated reservoir temperature, depth, and potential) at each site.
  - Site attribute values from USGS (2008) for identified resource potential, and capacity weighted averages of site attribute values from nearby identified resources for undiscovered resource potential.
  - GETEM used to estimate overnight capital cost, and parasitic plant losses that affect net energy production
- Typical geothermal plant size for hydrothermal resource sites are represented from 30 MW to 40 MW depending on technology type, binary or flash. https://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf, Slide 9.

References

U .S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model.

Williams, C.; Reed, M.; Mariner, R.; DeAngelo, J.; Galanis, S. (2008). Assessment of moderate- and high-temperature geothermal resources of the United States: U.S. Geological Survey Fact Sheet 2008-3082.



- Near Field-EGS Resource Potential based on data from USGS for EGS potential on the periphery of select, studied, identified hydrothermal sites estimated at 1,493 MW.
- Deep EGS resource potential (Augustine 2011), based on SMU Geothermal Laboratory temp-at-depth maps and methodology from MIT Future of Geothermal Energy Report
    - EGS resource is thousands of GW (16,000 GW) and many locations are likely not commercially feasible.
    - Approaches to restrict resource potential to about 500 GW based on USGS analysis may be implemented in the future.
- EGS generation plant cost and performance estimated for each potential site using GETEM, a bottom-up cost analysis tool that accounts for each phase of development of a geothermal plant. Model results based on resource attributes (estimated reservoir temperature, depth, and potential) at each site.
    - Site attribute values from USGS (2008) for identified resource potential, and capacity weighted averages of site attribute values from nearby identified resources for undiscovered resource potential.
    - GETEM used to estimate overnight capital cost, and parasitic plant losses that affect net energy production
- Typical geothermal plant size for enhanced geothermal system plants are represented by a range from 20 MW to 25 MW for binary or flash technologies. https://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf, Slide 9.

References

Augustine, C. (2011). Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input. 103 pp.; NREL Report No. TP-6A2-47459.

Robert, B. (2009). Geothermal Resource of the United States: Locations of Identified Hydrothermal Sites and Favorability of Deep Enhanced Geothermal Systems (EBS). National Renewable Energy Laboratory. http://www.nrel.gov/gis/pdfs/National%20Geothermal%20EGS%20Hydrothermal%20%202009.pdf

U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/sites/prod/files/2014/02/f7/geothermal_electricity_technology_evaluation_model_may_2011.pdf

Williams, C.; Reed, M.; Mariner, R.; DeAngelo, J.; Galanis, S. (2008). Assessment of moderate- and high-temperature geothermal resources of the United States: U.S. Geological Survey Fact Sheet 2008-3082.

Geothermal Plant CAPEX Definition

CAPEX = ConFinFactor*(OCC*CapRegMult + GCC)

Geothermal Generation Plant	Balance of System	Financial Costs

- CAPEX – expenditures required to achieve commercial operation in a given year
- Geothermal plant envelope includes:
  - Exploration, well field development, reservoir stimulation (EGS), plant equipment
  - Balance of System including installation, electrical infrastructure, and project indirect costs
  - Financial costs including owner's costs, electrical interconnection, and interest during construction (ConFinFactor)
- Regional cost variations and geographically specific grid connection costs not included in ATB (CapRegMult = 1; GCC = 0); ATB spreadsheet input is overnight capital cost (OCC) and details to calculate interest during construction (ConFinFactor).

- CAPEX in ATB based on GETEM model results using resource attributes (estimated reservoir temperature, depth, and potential) at each site.
- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs.

- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following based on GETEM component cost calculations and (Beamon and Leff, 2013):
  - Geothermal Generation Plant including
    - exploration (including exploration at "unsuccessful" sites), confirmation drilling, well field development, reservoir stimulation (EGS), and plant construction
    - power plant equipment, well-field equipment and components for wells (including dry/non-commercial wells)
  - Balance of System including
    - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results
- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., and neither does ReEDS
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, and neither does ReEDS

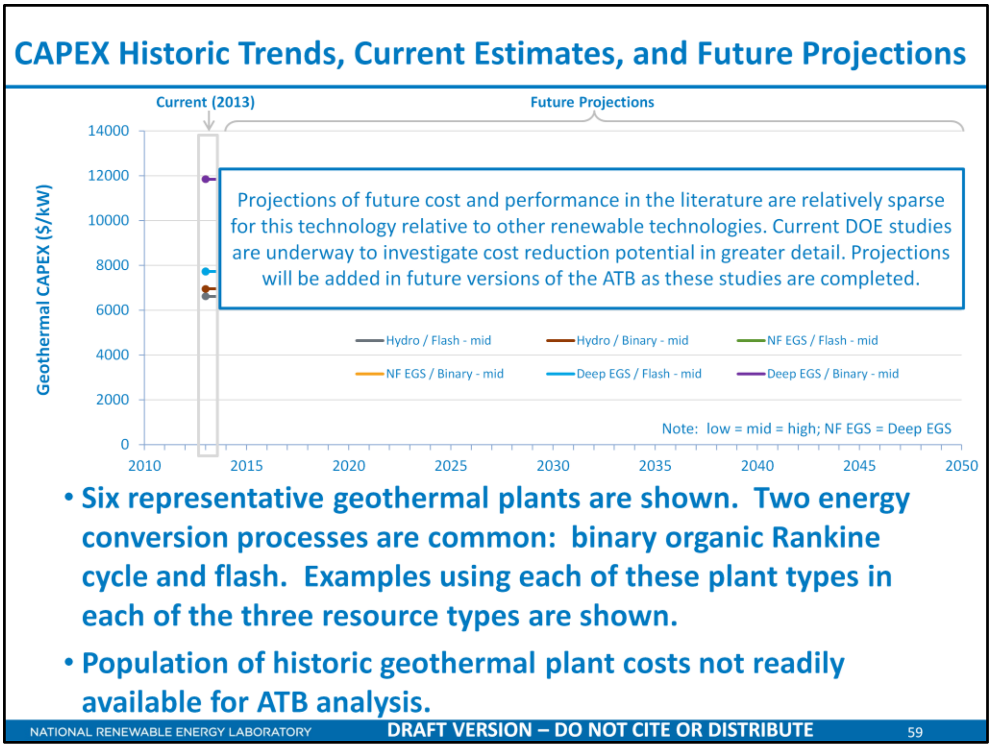
References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Mines, G.; and Nathwani, J. (2013). Estimated Power Generation Costs for EGS. Proceedings for the Thirty-Eight Workshop on Geothermal Reservoir Engineering. Stanford University, Stanford, California, February 11-13, 2013. Idaho National Laboratory and the U.S. Department of Energy.http://www.geothermal-energy.org/pdf/IGAstandard/SGW/2013/Nathwani.pdf?

U.S. Department of Energy (2014). "GETEM Development." U.S. Department of Energy website. http://www4.eere.energy.gov/geothermal/projects/1096.

U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model



- For illustration in ATB, six representative geothermal plants are shown. Two energy conversion processes are common: binary organic Rankine cycle and flash. Examples using each of these plant types in each of the three resource types, hydrothermal (hydro), near-hydrothermal field EGS (NF-EGS) and deep EGS, are shown.
- Costs are for new or "greenfield" hydrothermal projects, not for re-drilling or additional development/capacity additions at an existing site.
- Binary organic Rankine cycle plants use a heat exchanger to transfer geothermal energy to the steam turbine generator; this technology generally applies to lower temperature systems. Due to the increased number of components, lower temperature operation, and general requirement for a number of wells to be drilled for a given power output, these systems have higher CAPEX than flash systems.
- Flash plants create steam directly from the thermal fluid through a pressure change; this technology generally applies to higher temperature systems. Due to the reduced number of components, higher temperature operation, these systems generally produce more power per well reducing drilling costs. These systems generally have lower CAPEX than binary systems.
- Characteristics for the six example plants representing current technology were developed based on discussion with industry stakeholders (GTO internal). The CAPEX estimates were estimated using GETEM. CAPEX for NF-EGS and EGS are equivalent.
- CAPEX estimates do not include cost improvements with time. Geothermal is a fairly mature technology, as are the underlying technologies (drilling, power plant mainly) that drive costs. Historic trend data is difficult to obtain, due to the relatively small number of plants deployed each year and the difficulty in comparing costs across projects (since costs are highly site specific). Since anecdotal historical cost data does not point to decreasing costs with time and major advances in underlying technologies are unlikely without significant R&D, no assumptions about CAPEX cost improvements were included at this time.

Standard Scenario Model Results

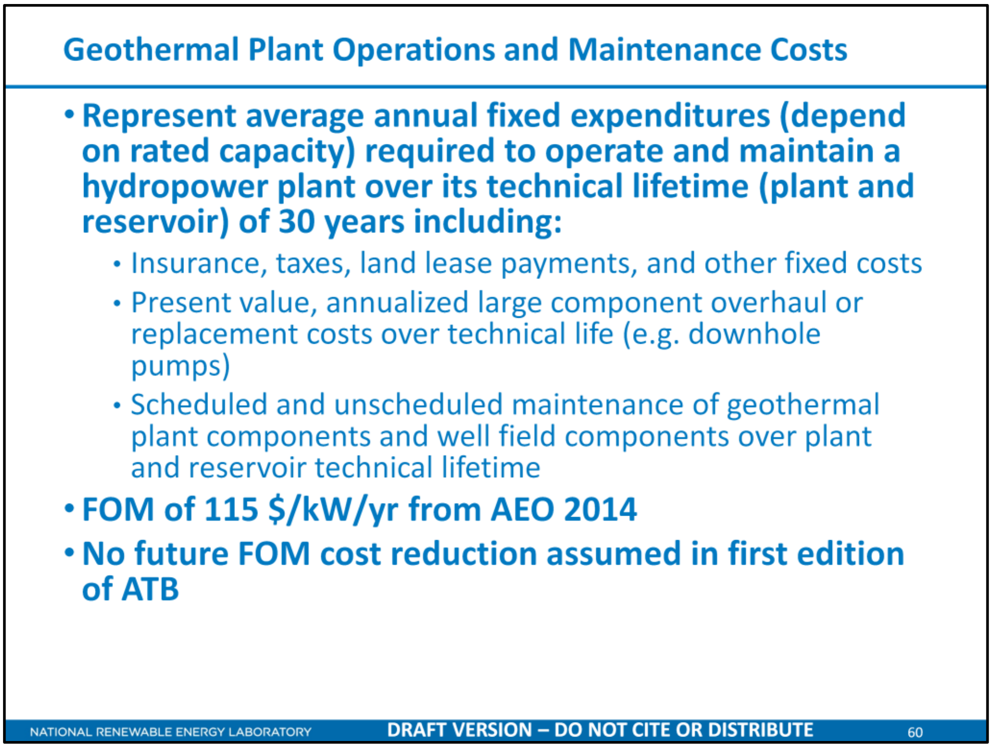
- ReEDS represents cost and performance for hydrothermal, NF-EGS and EGS potential in five bins for each of 134 geographic regions resulting in greater CAPEX range in the reference supply curve than what is shown in examples in ATB.

Future ATB Representation Under Consideration

- For this version of the ATB, future geothermal CAPEX are assumed to be the same as current costs. It is anticipated that ongoing GTO-directed analysis will improve this assumption for future versions of the ATB.

References

Mines, G.; Nathwani, J. (2013). Geothermal Electricity Technology Evaluation Model. U.S. Department of Energy, Geothermal Technologies Office 2013 Peer Review.
http://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf



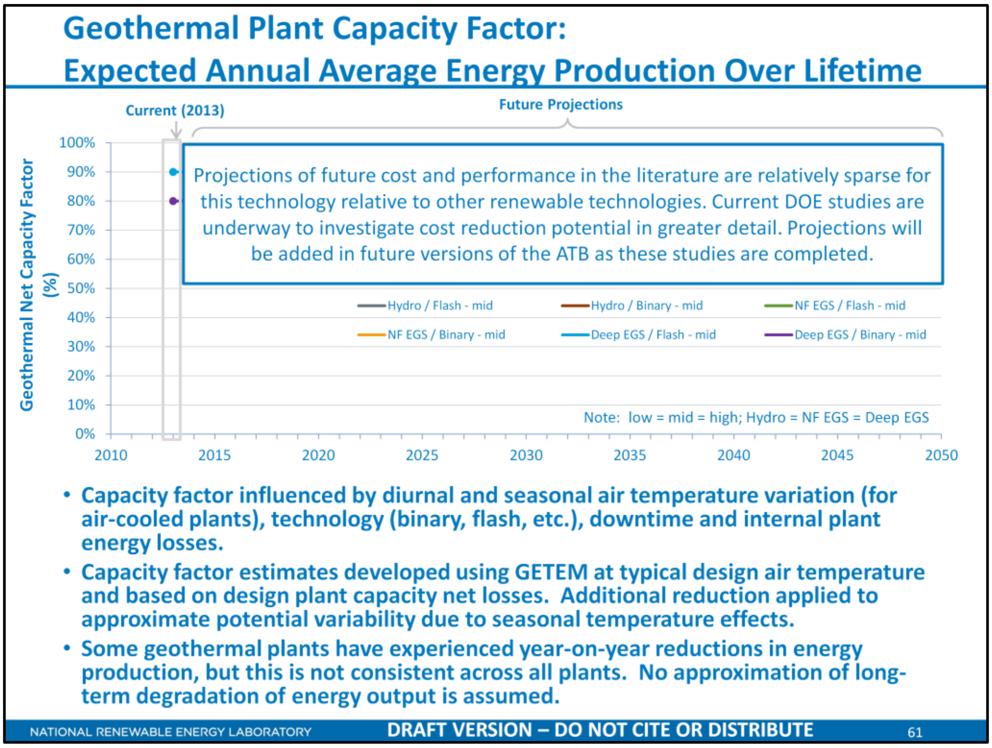
- Represent average annual fixed expenditures (depend on rated capacity) required to operate and maintain a hydropower plant over its technical lifetime (plant and reservoir) of 30 years including:
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component overhaul or replacement costs over technical life (e.g. downhole pumps)
    - Scheduled and unscheduled maintenance of geothermal plant components and well field components over plant and reservoir technical lifetime
- FOM of 115 $/kW/yr from AEO 2014.
- No future FOM cost reduction assumed in first edition of ATB

Standard Scenarios Model Results
- ReEDS Version 2015.1 standard scenario model results use FOM from AEO 2014 for all geothermal resource types and technologies.

Future ATB Representation Under Consideration
- GETEM used to estimate FOM for each of six representative plants; no variation with plant capacity is a simplification due to insufficient data that could be resolved using GETEM method.

References
U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/sites/prod/files/2014/02/f7/geothermal_electricity_technology_evaluation_model_may_2011.pdf

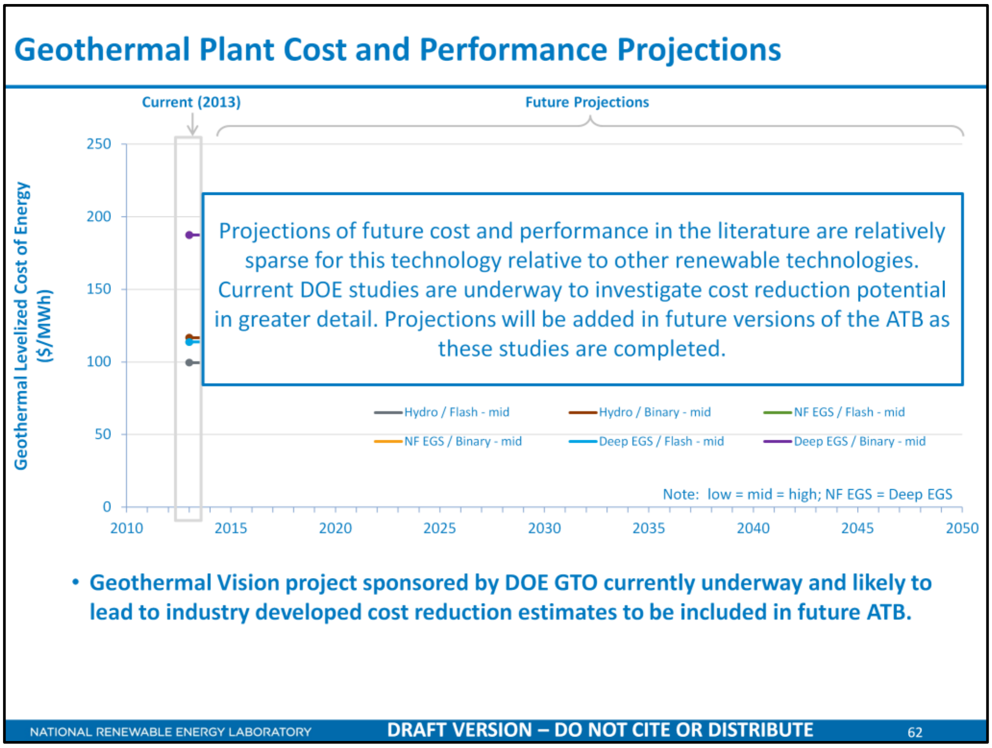
U.S. Energy Information Administration, U.S. Department of Energy (EIA). (2014a). *Annual Energy Outlook 2014 with Projections to 2040*. DOE/EIA-0383(2014). Washington, D.C.: U.S. Department of Energy Office of Integrated and International Energy Analysis. http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf



- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- Capacity factor influenced by diurnal and seasonal air temperature variation (for air-cooled plants), technology (binary, flash, etc.), downtime and internal plant energy losses.
- Capacity factor estimates developed using GETEM at typical design air temperature and based on design plant capacity net losses. Additional reduction applied to approximate potential variability due to seasonal temperature effects.
- Some geothermal plants have experienced year-on-year reductions in energy production, but this is not consistent across all plants. No approximation of long-term degradation of energy output is assumed.
- Ongoing work at NREL and INL is helping to improve capacity factor estimates for geothermal plants. As their work progresses, it will be incorporated into future versions of the ATB.

References

U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/sites/prod/files/2014/02/f7/geothermal_electricity_technology_evaluation_model_may_2011.pdf



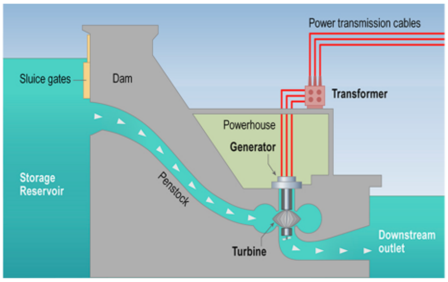
- Cost reduction projections for hydrothermal geothermal technologies or EGS technologies have not been found in initial literature review (sources such as IEA, EPRI). This may be due to the site-specific nature of geothermal plant cost, the relative maturity of hydrothermal plant technology and the very early stage development of EGS technologies.
- For this version of the ATB, future geothermal LCOE is assumed to be the same as the current LCOE.
- Geothermal Vision project sponsored by DOE GTO currently underway and likely to lead to industry developed cost reduction estimates to be included in future ATB.
- Areas identified as having potential cost reduction opportunities include:
    - development of exploration and characterization tools, which reduce well-field costs through risk reduction by locating and characterizing low- and moderate-temperature hydrothermal systems prior to drilling.
    - high-temperature tools and electronics for geothermal subsurface operations
    - novel or mixed working fluids in binary power plant designed to increase plant efficiency
    - advanced drilling system using flames or lasers to drill through rock; drilling steering technology; and other technologies to reduce drilling costs

Future ATB Representation Under Consideration

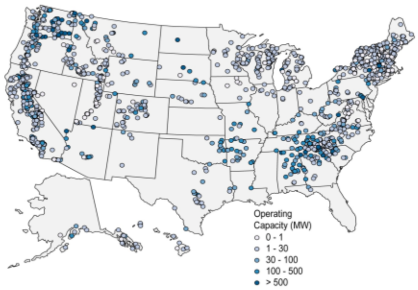
- Low cost scenario reflecting technology improvements to Hydrothermal geothermal plants by 2020 and to EGS plants by 2030 have been developed.

Note: pumped storage hydropower is considered a storage technology in ATB and will be addressed in future years. Pumped storage hydropower, and other storage technologies, are represented in Standard Scenarios Model Results from ReEDS model.

Hydropower – Upgrades to Existing Facilities



Source: NREL, 2012, Renewable Electricity Futures



Data Source: Homeland Security Infrastructure Program 2010

- **Hydropower technologies have produced electricity in the U.S. for over a century.**
- **As plants reach a license renewal period, upgrades to existing facilities to increase capacity or energy output are typically considered.**
- **Total potential: 7 GW / 25 TWh at about 2400 facilities**
- **Capital Expenditure (CAPEX) for each facility based on direct estimates where available.**
- **Capacity factor based on actual 10-year average energy production**

Upgrades of existing facilities are not included in the first edition of ATB.

Future ATB Representation Under Consideration

- Upgrade potential based on DOI, USACE, TVA and HAP case studies of existing facilities that estimate 6.9 GW/25 TWh at about 2400 facilities.
- Capital Expenditure (CAPEX) for each existing facility based on direct estimates (USBR HMI study) or relationship developed by INL as a function of capacity.
    - CAPEX = \$309,000*MW$^{0.7}$ + \$2,060,000*MW$^{0.81}$ from INL "Estimation of Economic Parameters of U.S. Hydropower Resources" (2003)
- Capacity factor based on actual10-year average energy production reported in EIA 923 forms. Hydropower facilities are typically operated to meet electric system operation and other reservoir management needs using their dispatch capability.
- No future cost reductions projections assumed; based on industry input during DOE Hydropower Vision project, cost projections may be developed and used in future ATB editions.

Standard Scenarios Model Results

- Future ReEDS versions will time upgrade potential availability with re-licensing date and or plant age.
- Upgrade potential not included in ReEDS Version 2015.1 standard scenarios model results.

References

DOI (Department of the Interior) et al. (2007), Potential Hydroelectric Development at Existing Federal Facilities, for Section 1834 of the Energy Policy Act of 2005, Department of the Interior.

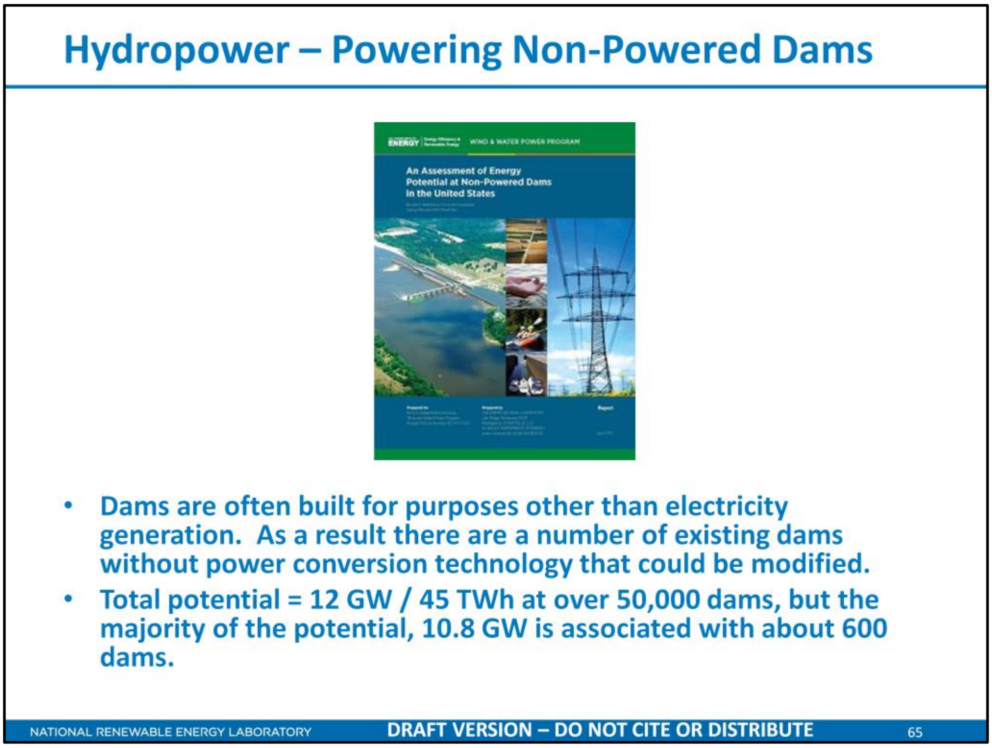
EIA (Energy Information Administration). (2013). 860, http://www.eia.gov/electricity/data/eia860/

Reclamation (U.S. Bureau of Reclamation). (2011). Hydropower Resource Assessment at Existing Reclamation Facilities, Denver, CO, March 2011.

USACE (U.S. Army Corps of Engineers). (1983). National Hydroelectric Power Resources Study, Report No. IWR-82-H-1, Washington, D.C.

USACE (U.S. Army Corps of Engineers). (2011). Hydroelectric Power Assessment—State of Hawaii. http://energy.hawaii.gov/wp-content/uploads/2011/10/HydroelectricPowerAssess.pdf.

TVA and HAP



- Resource potential estimated to be 12 GW / 45 TWh (assuming a capacity factor of 43%) at over 50,000 dams, but the majority of the potential, 10.8 GW is associated with about 600 dams (Hadjerioua, 2012).
- New hydropower facilities that result from adding power conversion technology to existing facilities are assumed to apply run of river operation strategies or run of release strategies. Run of river operation means that flow rate into reservoir is equal to flow rate out of facility. Run of release operation means that the facility may generate power from releases specified by the dam owner instead of inflows. These facilities do not have dispatch capability.
- CAPEX for each facility is based on analysis conducted by Idaho National Laboratory (Hall et al., 2003).
- Capacity factor estimated based on regional historic averages (Hadjerioua, 2012).

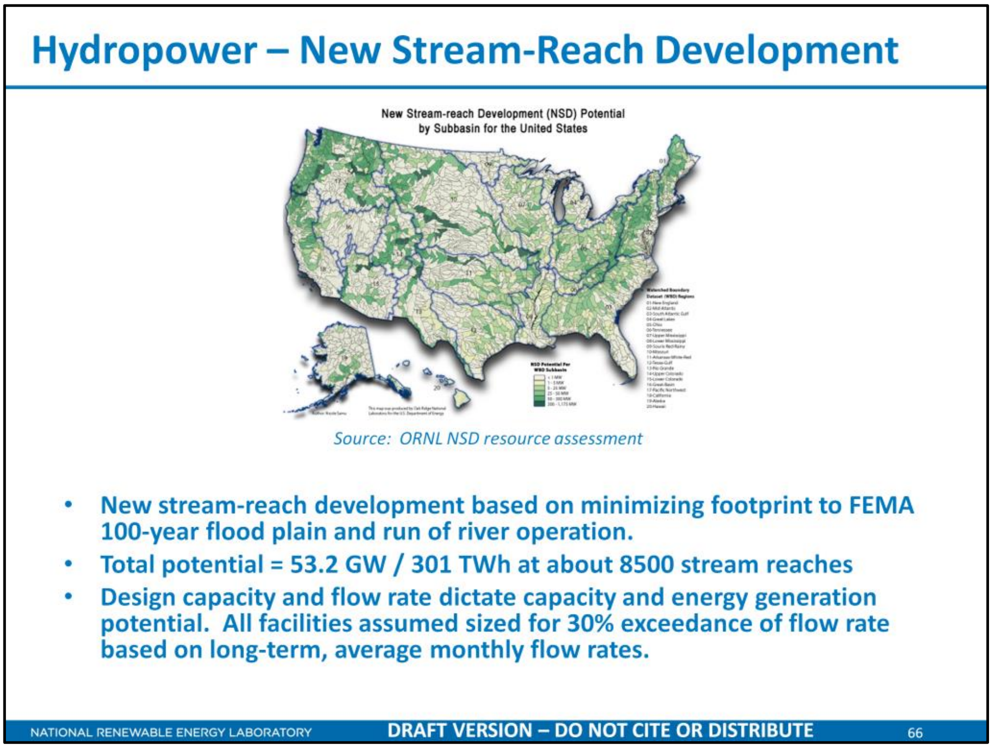
Future ATB Representations Under Consideration
- Resource potential estimated to be 5.7 GW / 32 TWh at about 600 facilities. Resource potential differs from previously published report due to a new methodology for sizing potential hydropower facilities that was developed for the New-Stream Reach Development resource. (Kao et al., 2014) This method is summarized below.
- About 600 existing facilities were evaluated to assess resource potential (capacity) and energy generation potential (CF). For each facility a design capacity, average monthly flow rate over a 20-year period and design flow rate exceedance level of 30% are assumed. The exceedance level represents the fraction of time that the design flow is exceeded. This parameter can be varied and results in different capacity and energy generation for a given site. The value of 30% was chosen based on industry rules of thumb. The capacity factor for a given facility is determined by these design criteria.
- CAPEX for each facility is based on regression analysis of historical construction costs; analysis underway by ORNL in support of Hydropower Vision project.

References
Hadjerioua, B. et al. (2012). An Assessment of Energy Potential at Non-Powered Dams in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. http://www1.eere.energy.gov/water/pdfs/npd_report.pdf

Hall et al. (2003). Estimation of Economic Parameters of U.S. Hydropower Resources. Idaho National Laboratory. http://www1.eere.energy.gov/water/pdfs/doewater-00662.pdf.

Kao et al. (2014). New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States

Oakridge National Laboratory. Hydropower Resource Map expected publication 2015.



- Resource potential estimated to be 53.2 GW / 301 TWh at about 8500 facilities. (Kao et al., 2014) after accounting for exclusions such as national parks, wild and scenic rivers, and wilderness areas.
- About 8500 stream reaches were evaluated to assess resource potential (capacity) and energy generation potential (CF). For each stream reach a design capacity, average monthly flow rate over a 20-year period and design flow rate exceedance level of 30% are assumed. The exceedance level represents the fraction of time that the design flow is exceeded. This parameter can be varied and results in different capacity and energy generation for a given site. The value of 30% was chosen based on industry rules of thumb. The capacity factor for a given stream reach is determined by these design criteria.
- Plant sizes range from kW to multi-MW (Kao et al., 2014).
- Resource assessment approach designed to minimize footprint of hydropower facility by restricting inundation area to FEMA 100 year flood plain.
- New hydropower facilities are assumed to apply run of river operation strategies. Run of river operation means that flow rate into reservoir is equal to flow rate out of facility. These facilities do not have dispatch capability.
- CAPEX for each facility is based on analysis conducted by Idaho National Laboratory (Hall et al., 2003).

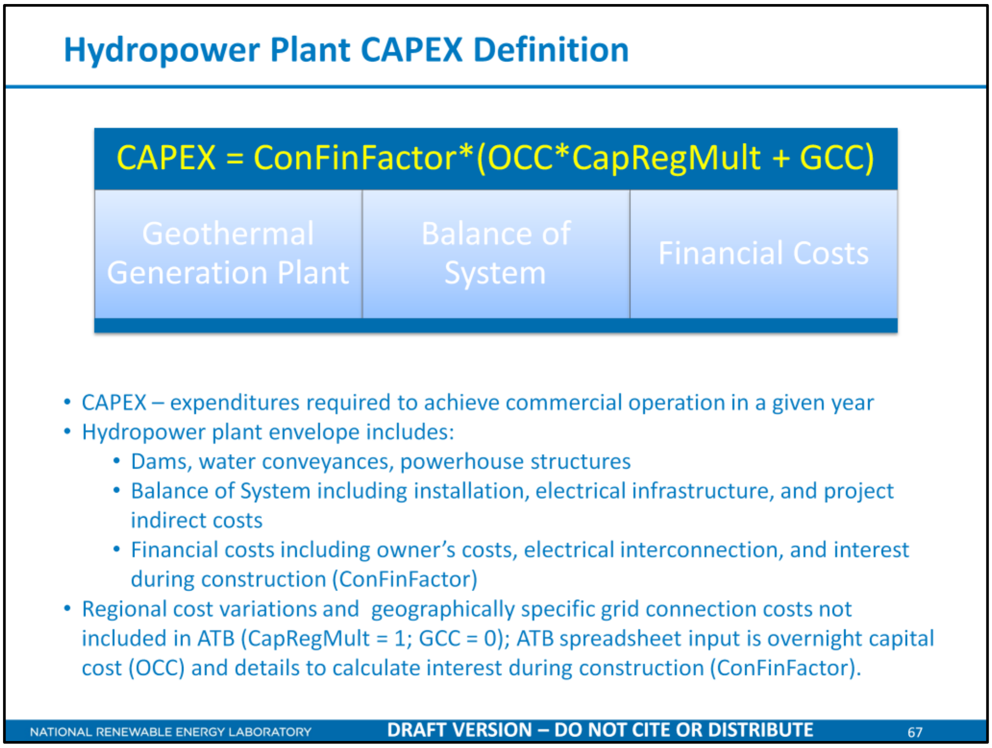
Future ATB Representation Under Consideration

- CAPEX for each facility is based on regression analysis of historical construction costs; analysis underway by ORNL in support of Hydropower Vision project.

References

Hall et al. (2003). Estimation of Economic Parameters of U.S. Hydropower Resources. Idaho National Laboratory. http://www1.eere.energy.gov/water/pdfs/doewater-00662.pdf.

Kao et al. (2014). New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. [New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States]



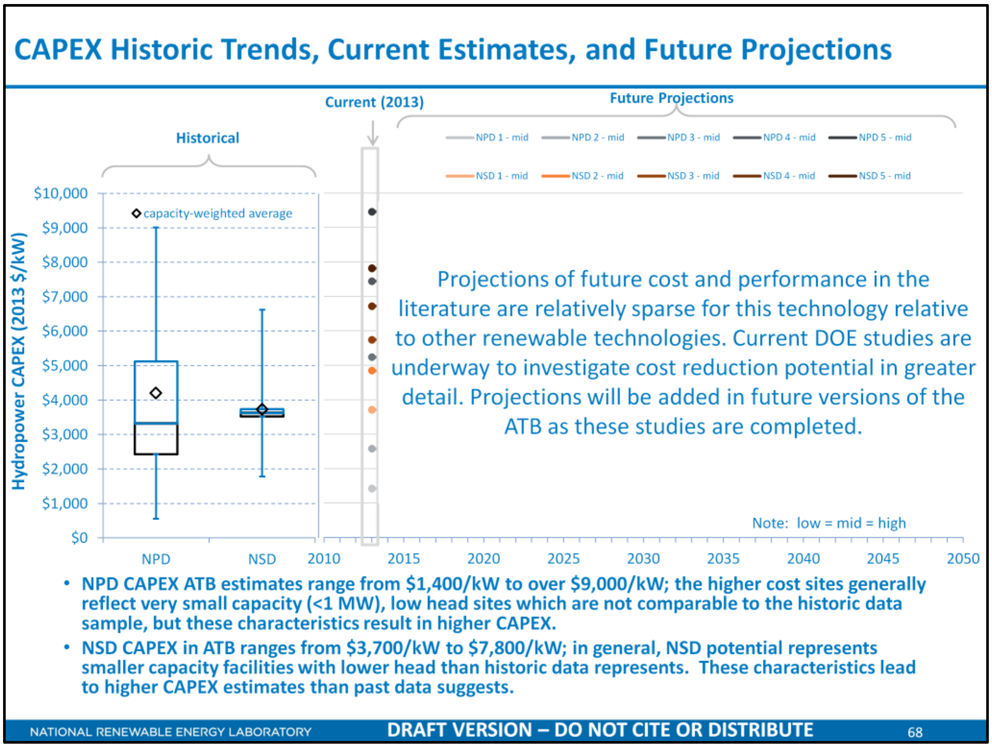
- CAPEX for each facility is based on analysis conducted by Idaho National Laboratory (Hall et al., 2003).
- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs.

- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following (Beamon and Leff, 2013; WWPTO CBS):
    - Hydropower Generation Plant including
        - site preparation, dams, water conveyances, powerhouse structures, powertrain equipment, ancillary plant electrical and mechanical systems
    - Balance of System including
        - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
        - project indirect costs including environmental mitigation equipment, engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
    - Financial Costs
        - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
        - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
        - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
            - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results
- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., and neither does ReEDS
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, and neither does ReEDS

References
Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

WWPTO CBS – Oak Ridge publication expected 2015?



- For illustration in ATB, all potential NPD and NSD sites were represented in five bins each. The bins were defined based on LCOE ranges. Capacity and generation for each of the technology bins are shown below.

Example projects are XXXXX of supply curves shown at right.	Available Capacity (GW)	Available Generation (GWh)
Non-Power Dams (NPD)	7.8	44,600
Non-Power Dams (NPD)	3.2	18,100
Non-Power Dams (NPD)	0.7	3,600
Non-Power Dams (NPD)	0.2	1,300
Non-Power Dams (NPD)	0.1	400
New Stream-Reach Development (NSD)	3.6	21,500
New Stream-Reach Development (NSD)	13.5	80,000
New Stream-Reach Development (NSD)	8.4	48,400
New Stream-Reach Development (NSD)	7.4	42,500
New Stream-Reach Development (NSD)	3.7	19,900

- Actual and proposed NPD and NSD CAPEX from 1981-2013 (ORNL data) are shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections.
- NPD CAPEX ATB estimates range from $1400/kW to over $9,000/kW; the higher cost sites generally reflect very small capacity (<1 MW), low head sites which are not comparable to the historic data sample, but these characteristics result in higher CAPEX.
- NSD CAPEX in ATB ranges from $3700/kW to $7,800/kW; in general, NSD potential represents smaller capacity facilities with lower head than historic data represents. These characteristics lead to higher CAPEX estimates than past data suggests.

Future ATB Representation Under Consideration

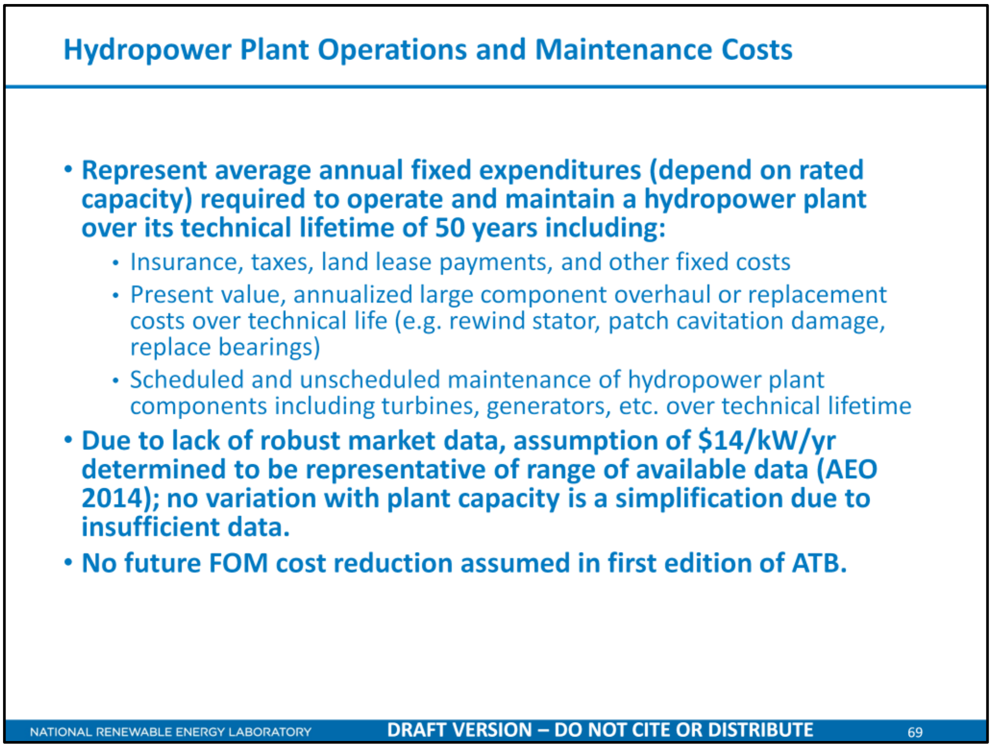
- CAPEX in ATB based on site head and capacity curves developed through regression analysis of actual and proposed projects from 1981-2013 (NPD) and from 1981-2013 (NSD) (in process, ORNL, anticipated publication , March 2015).
- NPD CAPEX ATB estimates range from $3700/kW to over $14,000/kW; the higher cost sites generally reflect very small capacity (<1 MW), low head sites which are not comparable to the historic data sample, but these characteristics result in higher CAPEX.
- NSD CAPEX in ATB ranges from $6400/kW to over $15,000/kW; in general, NSD potential represents smaller capacity facilities with lower head than historic data represents. These characteristics lead to higher CAPEX estimates than past data suggests.
- Historic data reflects projects that were realized while the current and future estimates reflect the total potential available. The historic data should then tend to represent the lower end of the range of the total resource potential.

Standard Scenarios Model Results

- ReEDS Version 2015.1 standard scenario model results use resource/cost supply curves representing estimates at each individual facility (~50,000 NPD, ~8500 NSD).
- ReEDS represents cost and performance for NPD and NSD potential in five bins for each of 134 geographic regions resulting in CAPEX range from $2300/kW to $66,000/kW for NPD resource and from $5500/kW to $13,000/kW for NSD.

References

- ORNL historic data.



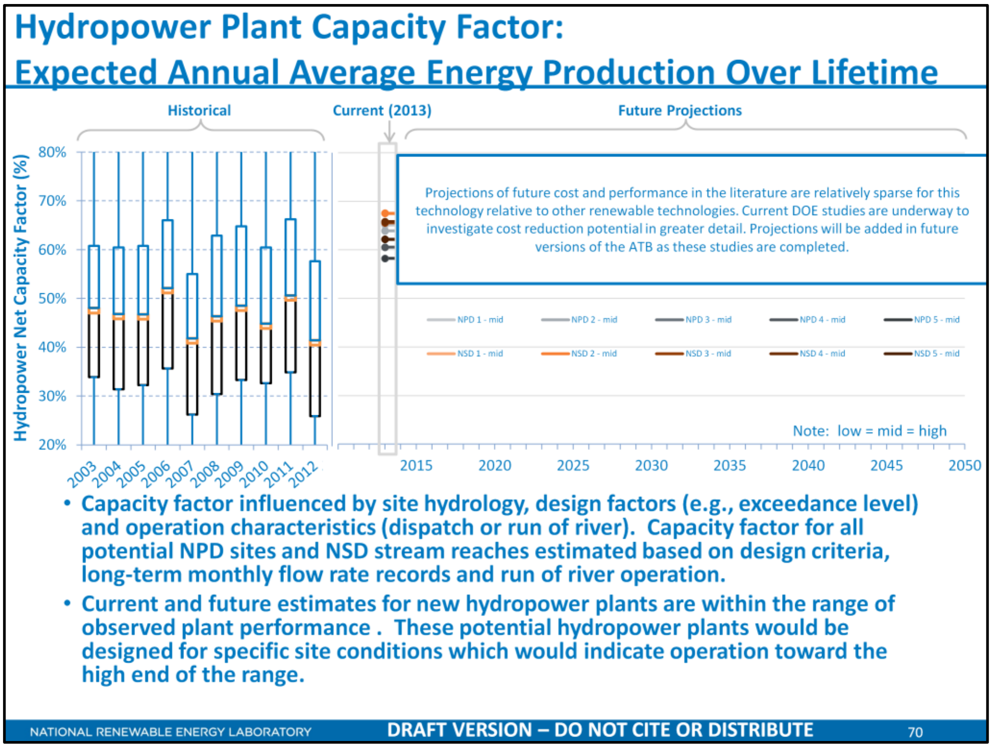
- Represent average annual fixed expenditures (depend on rated capacity) required to operate and maintain a hydropower plant over its technical lifetime of 50 years including:
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component overhaul or replacement costs over technical life (e.g. rewind stator, patch cavitation damage, replace bearings)
  - Scheduled and unscheduled maintenance of hydropower plant components including turbines, generators, etc. over technical lifetime
- Due to lack of robust market data, assumption of $14/kW/yr determined to be representative of range of available data (AEO 2014); no variation with plant capacity is a simplification due to insufficient data. Consistent with AEO a small VOM cost of $3/MWh is included.
- No future FOM cost reduction assumed in first edition of ATB.

Future ATB Representation Under Consideration

- Analysis of FERC Form-1 data on reported O&M costs may be used to provide improved resolution on O&M cost as a function of capacity.

References

AEO 2014



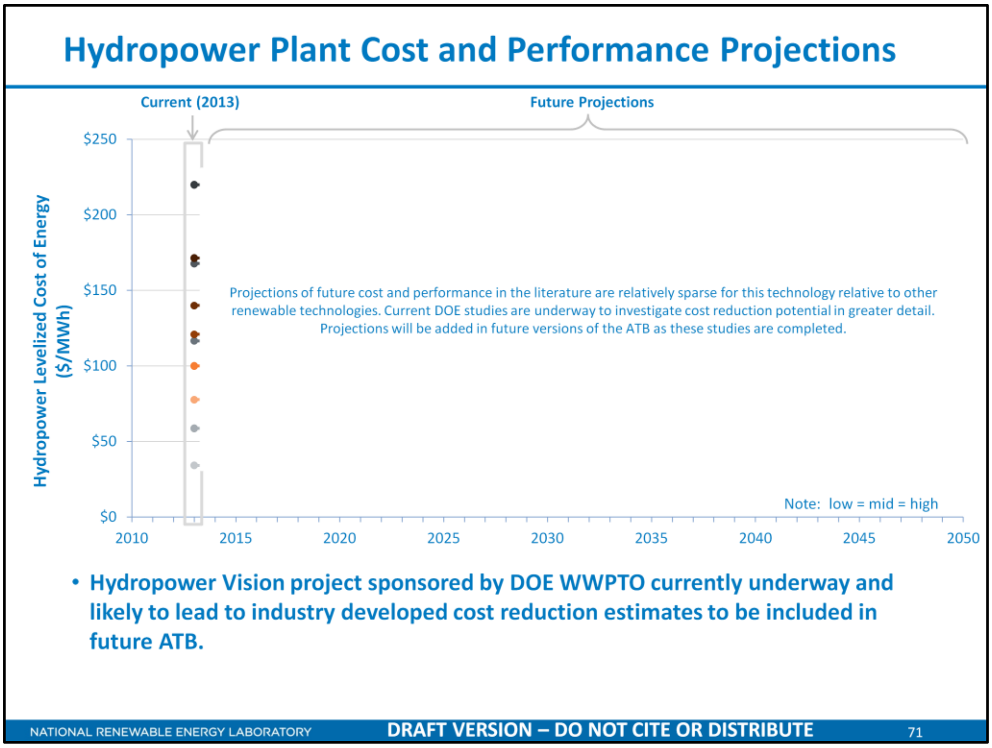
- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- Capacity factor influenced by site hydrology, design factors (e.g., exceedance level) and operation characteristics (dispatch or run of river). Capacity factor for all potential NPD sites and NSD stream reaches estimated based on design criteria, long-term monthly flow rate records and run of river operation.
- For illustration in ATB, all potential NPD and NSD sites were represented in five bins each. The bins were defined based on LCOE ranges and are described on an earlier slide.
- Actual energy production from about 200 run of river plants operating in the U.S. from 2003 to 2012 (EIA) is shown in box and whiskers format for comparison with current estimates and future projections. This sample includes some very old plants that may have lower availability and efficiency losses. It also includes plants that have been relicensed and may no longer be optimally designed for current operating regime (e.g., a peaking unit now operating as run of river). This contributes to the broad range, particularly on the low end.
- Current and future estimates for new hydropower plants are within the range of observed plant performance. These potential new hydropower plants would be designed for specific site conditions which would indicate operation toward the high end of the range.
- Inter-annual variation of hydropower plant output for run of river plants may be significant due to hydrological changes such as drought. This impact may be exacerbated by climate change over the long term.

Standard Scenarios Model Results

- ReEDS Version 2015.1 standard scenario model results use resource/cost supply curves representing estimates at each individual facility (~50,000 NPD, ~8500 NSD).
- ReEDS represents cost and performance for NPD and NSD potential in five bins for each of 134 geographic regions resulting in CF range from 20% to 84% for NPD resource and from 50% to 81% for NSD.
- Existing hydropower facilities in ReEDS provide dispatch capability such that their annual energy production is determined by the electric system needs by dispatching generators to accommodate diurnal and seasonal load variations and output from variable generation sources (wind and solar-PV).

References

- EIA data for historic capacity factor



- Cost reduction projections for hydropower technologies at existing facilities (upgrades), non-powered dams or new stream-reach development (low capacity, low head facilities) have not been found in initial literature review (sources such as EIA, IEA, EPRI). This may be due to site-specific nature of hydropower plant cost and performance, the relative maturity of the technology, and very limited new installations in the U.S. in recent years. Most hydropower deployment globally is associated with large reservoir applications unlike the potential low capacity, low head applications anticipated in the U.S.
- ATB assumes no change from current cost and performance through 2050.
- Hydropower Vision project sponsored by DOE WWPTO currently underway and likely to lead to industry developed cost reduction estimates to be included in future ATB.
- Areas identified as having potential cost reduction opportunities include:
    - modular “drop in” systems that minimize civil works and maximize ease of manufacture
    - research and development on environmentally enhanced turbines to improve performance of the existing hydropower fleet
    - efficient, certain, permitting, licensing, and approval procedures

Conventional Power Plants

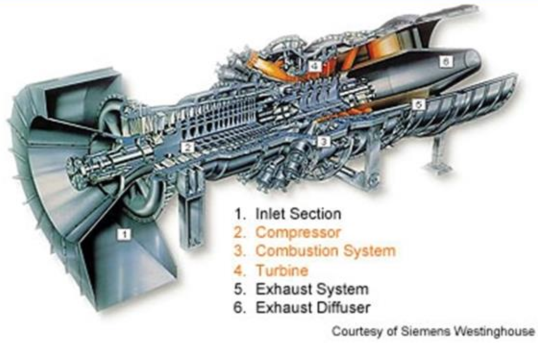
Conventional Technologies – Overview

- For the inaugural Annual Technology Baseline, the cost and performance of conventional technologies is taken directly from the Annual Energy Outlook, produced by the U.S. Department of Energy (DOE)'s Energy Information Administration
- The reference case does not include any carbon costs for any of the conventional technologies.
- Note that the capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type. Individual capacity factors for each plant's actual operation will vary significantly, and new investments likely would anticipate higher capacity factors.
- In future years, the ATB cost and performance of conventional technologies will also be informed by other DOE national laboratories and published literature.

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Natural Gas Plants

Natural Gas Power Plants – Technology Overview



The combustion (gas) turbines involve:

1. **The air compressor**, compresses and feeds it into the combustion chamber at hundreds of miles per hour.
2. **The combustion system.** A a ring of fuel injectors inject fuel into combustion chambers where it mixes with the air. The high temperature, high pressure gas stream enters and expands through the turbine.
3. **The turbine** has alternate stationary and rotating aerofoil-section blades, driven by expanding, hot combustion gas. The rotating blades drive the compressor and spin a generator to produce electricity.

Simple cycle gas turbine can achieve 20%-35% energy conversion efficiency. Future hydrogen and syngas fired gas turbine combined cycle plants are likely to achieve efficiencies of 60 percent or more. When waste heat is captured from these systems for heating or industrial purposes, the overall energy cycle efficiency could approach 80 percent.

Source: U.S. DOE “How Gas Turbine Power Plants Work”

http://energy.gov/fe/how-gas-turbine-power-plants-work

Natural Gas CapEx Required for Commercial Operation

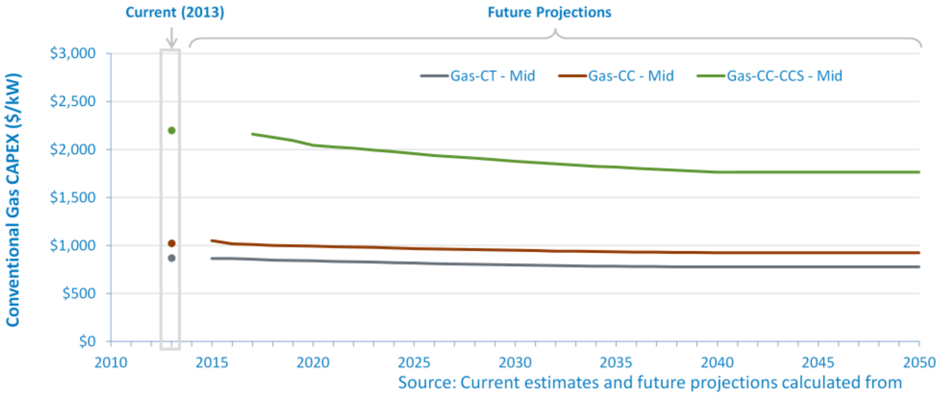
Natural Gas Technologies	
Gas-CT	Conventional Combustion Turbine
Gas-CC	Conventional Combined Cycle
Gas-CC-CCS	Combined Cycle with carbon capture sequestration

	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Gas-CT	$834	1.039	$867
Gas-CC	$983	1.039	$1,021
Gas-CC-CCS	$2,115	1.039	$2,198

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2014
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Fuel costs are just passed through to end user**
- **Fuel costs are also taken from EIA's AEO 2014**

Natural Gas - CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2014, modified.

- **A natural gas turbine (either combustion turbine /CT or combined cycle/CC) is a well-known technology that performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.**
- **The one exception is natural gas CC with carbon capture and storage (CCS). The U.S. Department of Energy's Fossil Energy office and the National Energy Technology Laboratory conduct research on reducing the costs and increasing the performance of the CCS technology and costs are expected to reduce over time**

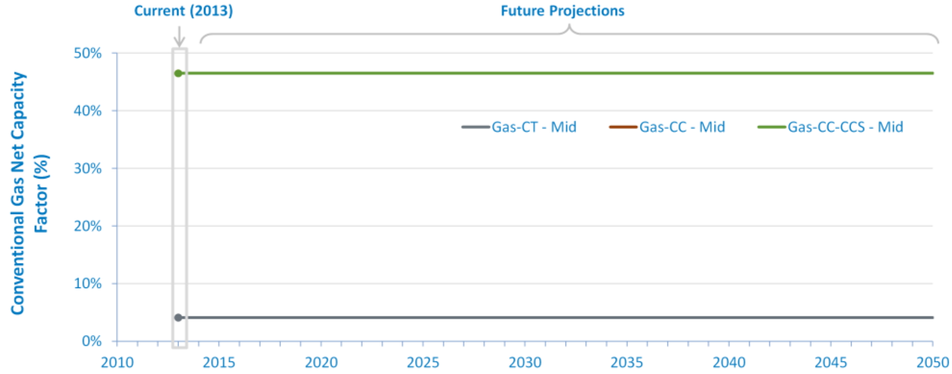
Natural Gas Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a natural gas power plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of natural gas power plants, transformers, etc. over technical lifetime
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

Photo credit: Duke Energy
H.F. Lee natural gas plant 1;
Goldsboro, NC
Taken on September 24, 2013

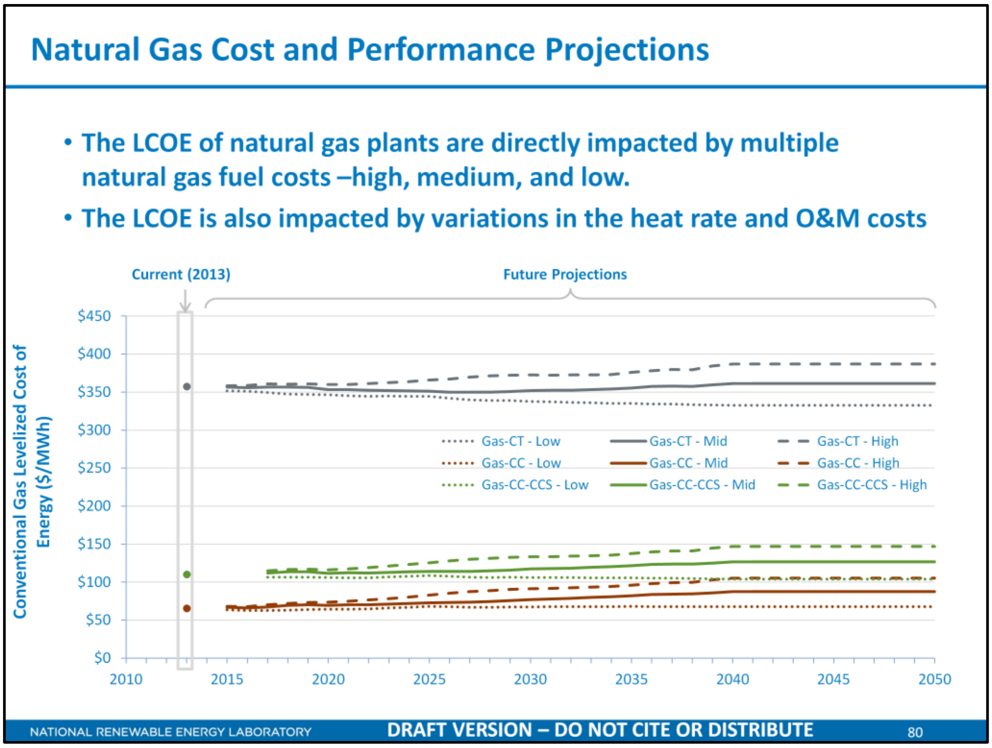
https://www.flickr.com/photos/dukeenergy/11441374433

Natural Gas – Capacity Factor: Annual Average Energy Production over Lifetime



Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2013 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a)

- **Natural gas CC power plants are typically baseload plants, with steady capacity factors.**
  - Today, NGCC is the most economic generation; it will run when not down for maintenance
- **Natural gas CT power plants are less efficient than CCs and tend to run as intermediate power plants, or as peakers (depending on market, time of day)**
- **Natural gas CC with CCS has not yet been built. It is expected to be a baseload unit. While it may have a derate due to the emissions capture at the end, we assumed the same capacity factor for NGCC and NGCC - CCS.**

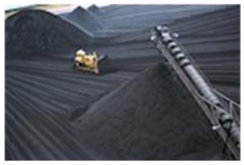


The reference case does not include any carbon costs for conventional technologies.

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Coal Plants

Coal Power Plant – Technology Overview



Niagara Mohawk's Dunkirk steam station in New York – soon to be set up for cofiring biomass

Photographer: David Parsons
Source: NREL photo library 06705.jpg and 06735.jpg

Electrical transmission lines in front of coal-fired power plant
Photographer: Warren Getz
Source: NREL photo library 10933.jpg

1. **Heat is created:** coal is pulverized, mixed with hot air and burnt in suspension
2. **Water turns to steam**: the heat turns purified water into steam and is piped to the turbine
3. **Steam turns the turbine:** the pressure of the steam pushes the turbine blade, turns the shaft in the generator and creates power
4. **Steam turned back into water**: cool water is drawn into a condenser where the steam turns back into water that can be used over again in the plant.

Adapted from: Duke Energy's website; http://www.duke-energy.com/about-energy/generating-electricity/coal-fired-how.asp

http://www.duke-energy.com/about-energy/generating-electricity/coal-fired-how.asp

Coal Generation CapEx Required for Commercial Operation

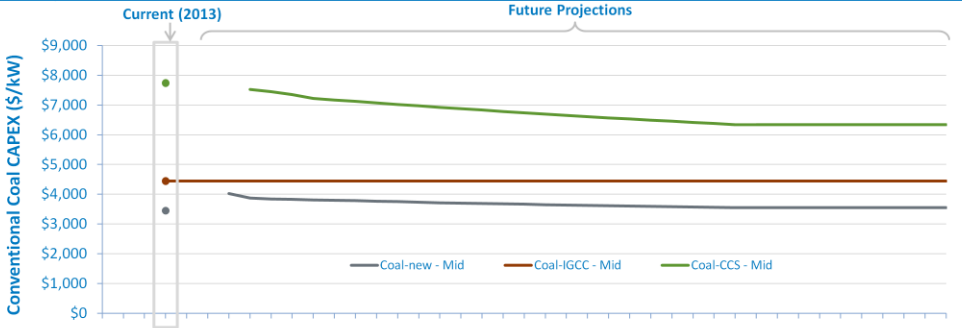
Coal Generation Technologies	
Coal-new	Advanced super critical with SO2 and NOx controls
Coal-IGCC	Integrated gasification combined cycle (IGCC)
Coal-CCS	IGCC with carbon capture & sequestration (CCS) options

	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Coal-new	$2,969	1.186	$3,520
Coal-IGCC	$3,828	1.186	$4,538
Coal-CCS	$6,666	1.186	$7,903

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2014
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Fuel costs are just passed through to end user**
- **Fuel costs are also taken from EIA's AEO 2014**

Coal – CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2014, modified.

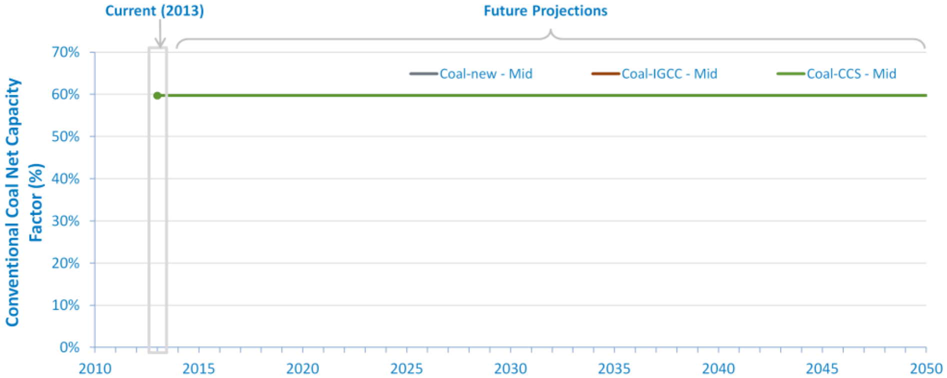
- **A coal power plant is a well-known technology that already performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.**
- **There are two exceptions. The U.S. Department of Energy's Fossil Energy office and the National Energy Technology Laboratory conduct research on reducing the costs and increasing the performance of :**
  - Integrated gasification combined cycle (where the coal is gasified, and then fed into a combined cycle turbine usually used to burn natural gas)
  - Coal in combination with carbon capture and storage (CCS). The CCS technology and costs are expected to reduce over time

Coal Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a coal plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of coal power plants, transformers, etc. over technical lifetime
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

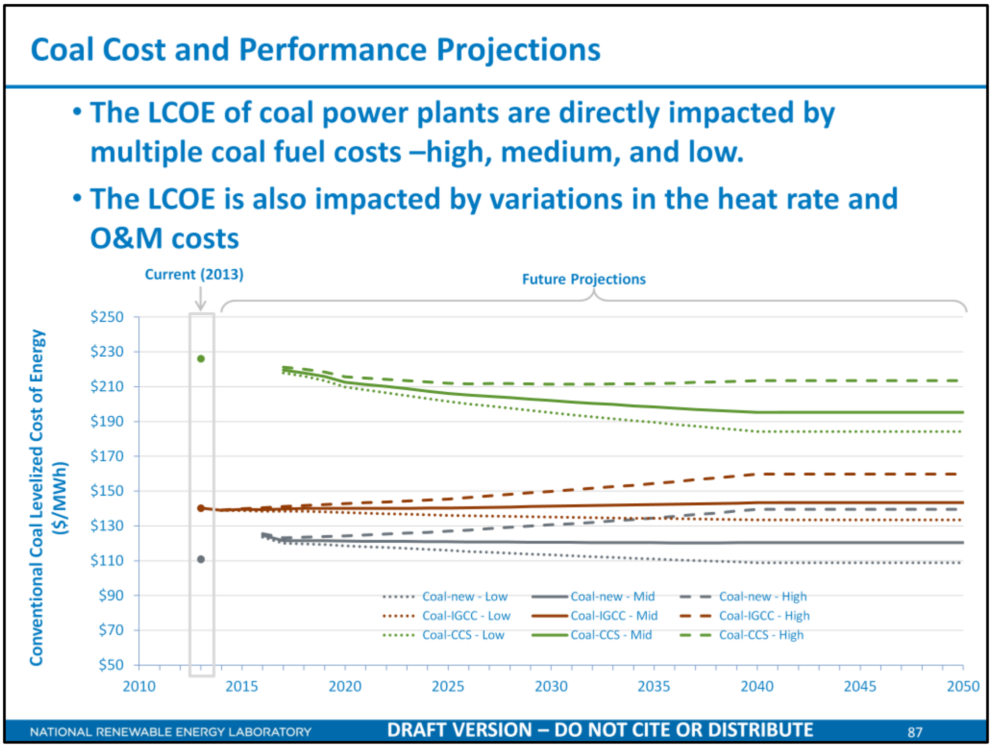
Cherokee Station coal-powered plant, Denver, Colorado
Photographer: Warren Getz
Source: NREL photo library 06360.jpg

Coal – Capacity Factor: Annual Average Energy Production over Lifetime



Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2013 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a)

- **Coal power plants are typically baseload plants, with steady capacity factors.**
- **Even though IGCC and Coal with CCS have not yet been deployed in the United States, it is expected that their characteristics would be similar to new coal power plants, so all capacity factors are at 85%.**



The reference case does not include any carbon costs for conventional technologies.

Nuclear Plants

Nuclear Power Plant – Technology Overview

Source: TVA Watts Bar Nuclear Power Plant | Photo courtesy of Tennessee Valley Authority
http://www.energy.gov/ne/nuclear-reactor-technologies

- Nuclear power contributed about 20% of U.S. electrical generation over the past two decades.
- Atoms have a large amount of energy holding their nuclei together. Isotopes of some elements can be split and will release part of their energy as heat. This splitting is called fission. The heat released in fission can be used to help generate electricity in power plants.
- During fission, U-235 atoms absorb loose neutrons. This causes U-235 to become unstable and split into two light atoms called fission products. The combined mass of the fission products is less than that of the original U-235. The reduction occurs because some of the matter changes into energy (namely heat). Two or three neutrons are released along with the heat. These neutrons may hit other atoms, causing more fission.
- A series of fissions is called a chain reaction. If enough uranium is brought together under the right conditions, a continuous chain reaction occurs. This is called a self-sustaining chain reaction, which creates a great deal of heat, which can be used to help generate electricity.
- Nuclear power plants generate electricity like any other steam-electric power plant. Water is heated, and steam from the boiling water turns turbines and generates electricity. The main difference is that heat from a self-sustaining chain reaction boils the water in a nuclear power plant (as opposed to burning fuels in fossil fuel plants).

http://energy.gov/ne/nuclear-reactor-technologies/light-water-reactor-sustainability-lwrs-program
http://energy.gov/ne/about-us/history
http://www.energy.gov/ne/nuclear-reactor-technologies

Nuclear Generation CapEx Required for Commercial Operation

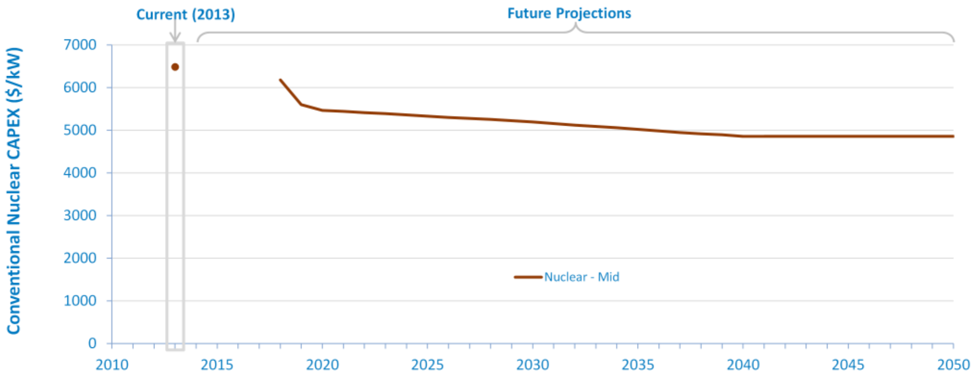
Nuclear Generation Technology	
Nuclear	Advanced nuclear power generation

	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Nuclear	$5,584	1.186	$6,620

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2014
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Costs are also taken from EIA's AEO 2014**

Nuclear – CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2014, modified.

- **A nuclear power plant is a well-known technology that already performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.**

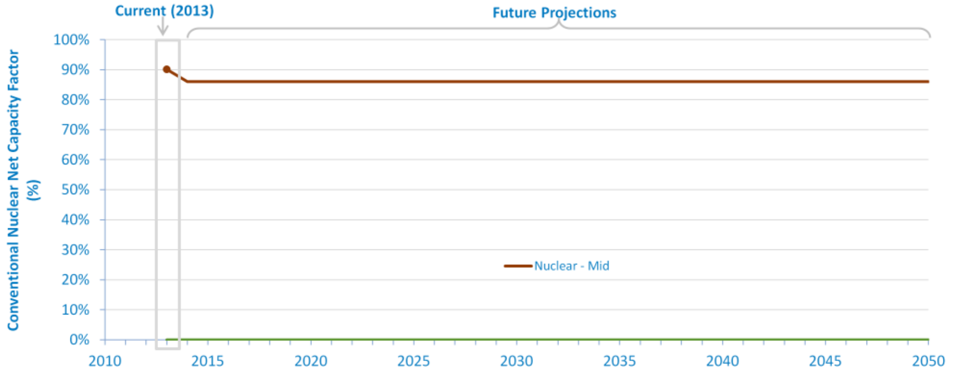
Nuclear Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a nuclear plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of nuclear power plants, transformers, etc. over technical lifetime
  - Fuel rod replacement, storage, and handling
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

Photo credit: Idaho National Laboratory
Nuclear operating crews run simulations with the HSSL research team
Taken on November 7, 2012

https://www.flickr.com/photos/inl/9420873449/

Nuclear – Capacity Factor: Annual Average Energy Production over Lifetime



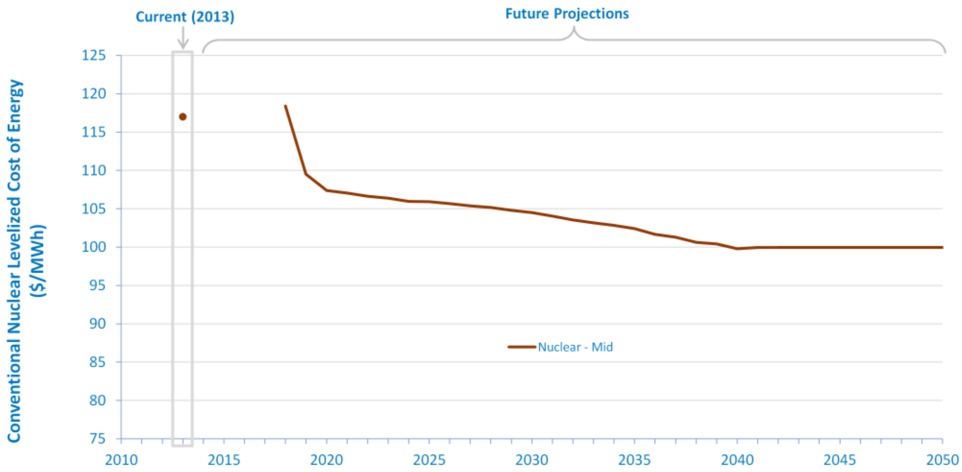
Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2013 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a)

- **Nuclear power plants are typically baseload plants, with steady capacity factors.**
- **Nuclear power plants need to change out their uranium fuel rods about every 24 moths. After 18-36 months, the used fuel is removed from the reactor. The average fueling outage duration in 2013 was 41 days; from 1990-1997, the refueling days ranged from 66-106, so improvements have helped capacity factors.**
- **According to the Nuclear Energy Institute, the average capacity factors for nuclear power plants was 90.9% in 2013. In fact, since 2007, the capacity factors have ranged between 86.4% - 91.8%.**

http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Introduction/Nuclear-Fuel-Cycle-Overview/
http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Refueling-Outage-Days
http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants
http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Capacity-Factors

Nuclear Cost and Performance Projections

- The LCOE of nuclear power plants are directly impacted by the cost of uranium, variations in the heat rate, and O&M costs.
- The downtime from refueling nuclear power plants is another big factor.



NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Biomass Plants

Biomass Power Plant Technology Overview

NIPSCO generating station
Photographer: Photographer: Kevin Craig
Source: NREL photo library, 08928.jpg

McNeil Generating Station in Burlington, VT operates on wood chips
Photographer: David Parsons
Source: NREL photo library, 06905.jpg

1. **Heat is created:** biomass (sometimes co-fired with coal) is pulverized, mixed with hot air and burnt in suspension
2. **Water turns to steam**: the heat turns purified water into steam; is piped to the turbine
3. **Steam turns the turbine:** the pressure of the steam pushes the turbine blade, turns the shaft in the generator and creates power
4. **Steam turned back into water**: cool water is drawn into a condenser where the steam turns back into water that can be used over again in the plant.

Adapted from: Duke Energy's website

Biomass Generation CapEx Required for Commercial Operation

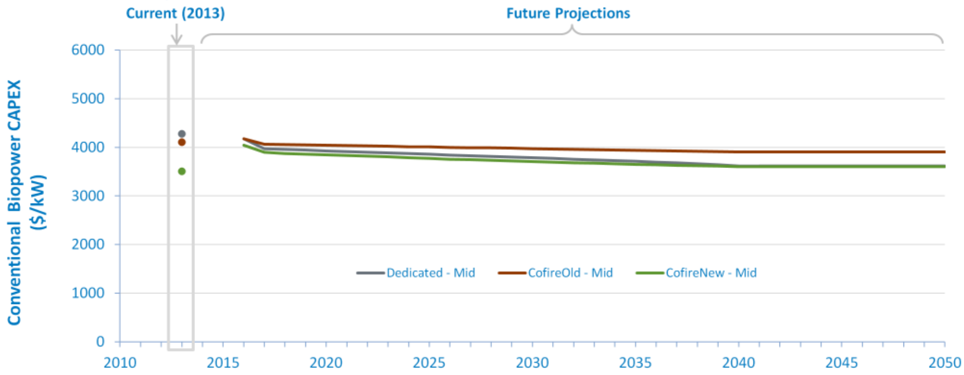
Biomass Generation Technologies	
Dedicated	Dedicated biomass plant
CofireOld	Pulverized coal with sulfur dioxide (SO2) scrubbers and biomass co-firing
CofireNew	Advanced super critical coal with SO2 & NOx controls and biomass co-firing

	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Dedicated	$3,987	1.186	$4,716
CofireOld	$3,817	1.186	$4,525
CofireNew	$3,259	1.186	$3,864

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2014
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Fuel costs are just passed through to end user**
- **Fuel costs are also taken from EIA's AEO 2014**

Biomass – CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2014, modified.

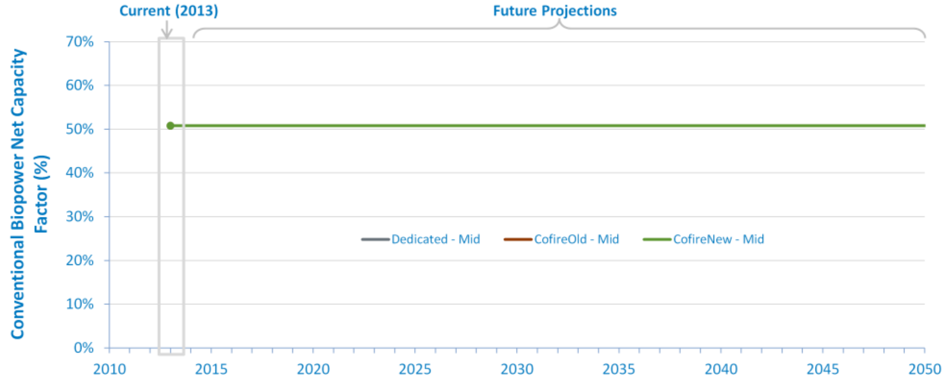
- **A biomass power plant is a well-known technology that performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.**
- **The exception is new biomass cofiring, which is expected to have the costs reduce a bit more than existing cofiring project technologies.**

Biomass Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a biomass plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of biomass power plants, transformers, etc. over technical lifetime
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

McNeil Generating Station at Burlington, VT – a biomass gasifier which operates on wood chips.
Photographer: Warren Gretz
Source: NREL photo library, 06382.jpg

Biomass – Capacity Factor:
Annual Average Energy Production over Lifetime

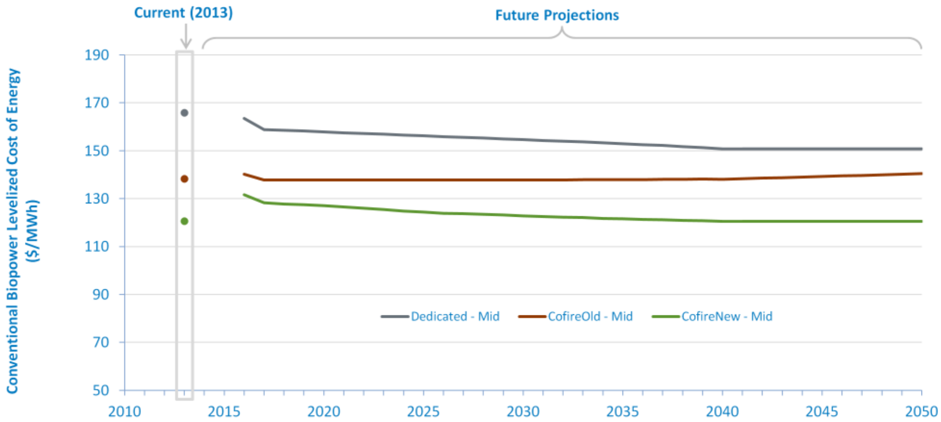


Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2013 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a)

- **Biomass power plants are typically baseload plants, with steady capacity factors.**
- **Biopower capacity factors are influenced by technology and feedstock supply, expected downtime, and energy losses.**

Biomass Cost and Performance Projections

- The LCOE of biomass power plants are directly impacted by the differences in CAPEX (installed capacity costs), as well as heat rate differences.
- Regional variations will ultimately impact biomass feedstock costs, but those are not included in this analysis.



NATIONAL RENEWABLE ENERGY LABORATORY DRAFT VERSION – DO NOT CITE OR DISTRIBUTE 10

The reference case does not include any carbon costs for conventional technologies.