Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 3rd, 2015

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. Approved the use of new "Other GI Firm" resources [not designated to a utility] to meet any potential renewable Mandate or Goal shortfalls.
2. Approved the resource inclusion methodology for the ITP studies, including the process of sending a request to the ESWG for resources that do not meet the criteria.
3. Approved the use of prototypes from Lazard's 2014 Levelized Cost of Energy Study (Version 8).
4. Approved the use of 2012 hourly wind profiles from the NREL 2012 WIND toolkit dataset.

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ECONOMIC STUDIES WORKING GROUP

June 3rd, 2015

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• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:30 AM, welcomed those in attendance, and asked for introductions.

There were 45 web conference participants and 1 telephone participant representing 11 of 12 ESWG members. (Attachment 1 – June 3rd, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Don Le (NextEra) named Brian Gedrich (NextEra) as his proxy. (Attachment 2 – Proxies)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – June 3rd, 2015 Agenda)

> **Kip Fox (AEP-Transource) made a motion; seconded by Kurt Stradley (LES) to adopt the agenda. The motion was approved unanimously.**

Agenda Item 2 – 2017 ITP10 Generation and Load Review Update

Kelsey Allen (SPP Staff) gave an update to the group. He reminded them that June 2nd was the deadline for feedback on the Economic Model data and that staff is currently reviewing all of the updates for inclusion in the model.

Agenda Item 3 – ITP Resource Expansion Methodology

Kelsey Allen (SPP Staff) gave a presentation of the ITP resource expansion methodology. The response window for the renewable survey has closed and for companies who did not submit a response, staff will calculate values based on available state Mandates/Goals and the information in the Generation and/or Load review. These calculations will be provided to the Stakeholder for review. Staff recommended using non designated "Other GI Firm" resources to meet any potential renewable Mandate or Goal shortfalls.

> **Kip Fox (AEP-Transource) made a motion; seconded by Brian Gedrich (NextEra) to approve the use of new "Other GI Firm" resources [not designated to a utility] to meet any potential renewable Mandate or Goal shortfalls. The motion was approved unanimously.**

Kelsey reviewed the proposed ITP10/20 resource inclusion criteria:

Resources are to be included in the model if they have an executed Interconnection Agreement that is not on suspension and has minimal network upgrade costs. Otherwise, the facility will be included if it has a high probability of going into service and;

- a Resource Addition Request (RAR) has been sent to SPP requesting the generation capacity be included into the ITP**;**
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA; and
- The generating resource will have firm contract for delivery in one or more forms:

  - a) The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts; or
  - b) The utility to be designated will own and operate the resource or has procured a Purchase Power Agreement (PPA) from the generation owner.
- If a generating resource does not meet all the above requirements, a RAR for generation capacity to be included in a long-term ITP assessment can be made to ESWG on a case by case basis. ESWG will take into account the following, but not limited to, additional points:
  - i) a Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable;
  - ii) an RFP for the generating resource has been awarded, if applicable. All other resource expansion needs will be determined through the SPP resource planning process.

(Attachment 4 – ITP Resource Expansion Methodology)

Kip Fox (AEP-Transource) made a motion; seconded by Paul Dietz (Westar) to approve the proposed resource inclusion methodology for the ITP studies, including the process of sending a request to the ESWG for resources that do not meet the criteria. The motion was approved unanimously.

Agenda Item 4 – 2017 ITP10 Scope

Kelsey Allen (SPP Staff) presented prototype data source option to the group. In past ITP studies, the EIA Annual Energy Outlook report has been leveraged. Staff recommended utilizing the Lazard levelized cost of energy analysis data. The group agreed with this recommendation and requested that staff come back with details of how we will utilize the available data. (Attachment 5 – 2017 ITP10 Scope) (Attachment 6 - 2014 Lazard-Levelized Cost of Energy-Version 8.0)

Paul Dietz (Westar) made a motion; seconded by Leon Howell (OG&E) to approve using the Lazard data set for generation prototypes. The motion was approved unanimously.

Discussion moved on to the wind capacity factors, Kelsey reminded the group that in the last study, we used the 2005 NREL EWITS profiles, and increased the capacity factors of new wind farms by 15%. For the 2017 ITP10, staff is recommending to utilize the 2012 NREL toolkit dataset. This dataset was not available during the 2015 ITP10, it has higher capacity factors that reflect technological advances and it is also more comprehensive.

Leon Howell (OG&E) made a motion; seconded by Paul Dietz (Westar) to approve using the 2012 hourly wind profiles from the NREL 2012 WIND toolkit dataset. The motion was approved unanimously.

The group briefly discussed benchmarking and determined that they would like to continue looking at the same data as we have in previous studies; capacity factor by unit type, generation by unit type, production cost, LMP's, etc. The group also agreed to use the same process for the constraint assessment, beginning with the IDC Book of Flowgates and adding additional constraints using PAT.

When the topic of solution development was brought up, the main topic of conversation was the seams project cost sharing methodology. The 80/20 cost sharing may be the best option with some of our neighbors, but stakeholders would like to re-evaluate the cost sharing with MISO. Staff was also asked to investigate the 1-year B/C threshold by pulling data from past studies and looking at the addition of all metrics, the addition of the 40-year benefits, and the change in costs between Study and Conceptual estimates. The ESWG asked for more time to think about project selection and project grouping, but there was some concern about the 70% congestion relief threshold Staff used to filter potential economic projects.

Closing Items

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion.

There were no official action items from the meeting. SPP Staff and ESWG members will continue to refine methodology and ideas for the 2017 ITP10 scope and study.

The meeting was adjourned at 11:30 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Name	Attendance	Company
Alan Myers	Webex	
Anita	Webex	
Bennie Weeks	Webex	
Bethany King	Webex	
Bill Leung (NPRB)	Webex	
Blaine Erhardt	Webex	
Brett Hooton	Webex	
Brian Buffington (Xcel)	Webex	
Brian Gedrich	Webex	
Cindy Ireland (AR PSC)	Webex	
Deral Danis	Webex	
ed pfeiffer (quanta)	Webex	
Eric Burkey	Webex	
Gayle Freier	Webex	
Henry Tilghman	Webex	
Jason Frasier	Webex	
Jason Schmidt (Xcel)	Webex	
Jeremy Harris (WERE)	Webex	
Jeremy Severson (BEPC)	Webex	
Jerry Bradshaw (SPRM)	Webex	
Jody Holland	Webex	
Joe Fultz	Webex	
John Boshears	Webex	
Jon Shipman (OPPD)	Webex	
Jordan Schmick	Webex	
Kim McClafferty	Webex	
Kip Fox (AEPTHC)	Webex	
Kirk Hall	Webex	
Kurt Stradley (LES)	Webex	
Leon Howell	Webex	
Michael Massery (AECC)	Webex	
Michael Odom (SPP)	Webex	
Michael Watt (OMPA)	Webex	
Michael Wegner (ITC)	Webex	
Monica Evans	Webex	
Natasha	Webex	
Pat McCool	Webex	
Paul Dietz	Webex	
Randy Collier (CUS)	Webex	
sam loudenslager (SPP)	Webex	
Steve Gaw	Webex	
Tim Owens (NPPD)	Webex	
Wayman Smith	Webex	
Heather Starns	Phone	MJMEUC/CUS/SCMCN
Kelsey Allen	Webex	SPP
Juliano Freitas	Webex	SPP

1. Don Le proxy to Brian Gedrich

Brian Gedrich has my proxy for the June 3, 2015 Meeting as I will be unable to attend.

Thanks,
Don Le
System Planning Manager
Lone Star Transmission, LLC
NextEra Energy Transmission, LLC
(M) 713-366-6105
(O) 512-236-3144
Don.Le@NextEraEnergy.com

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 3rd, 2015

Net Conference

• AGENDA •

8:30 am – 11:30 am

1. Administrative Items
   a. Call to Order, Introductions........Alan Myers (5 minutes)
   b. Receipt of Proxies........Kelsey Allen (1 minute)
   c. Review of Agenda[1]........Alan Myers (1 minute)
2. 2017 ITP10 Generation and Load Review Update........SPP Staff (10 minutes)
3. ITP Resource Expansion Methodology[1]........SPP Staff (45 minutes)
4. 2017 ITP10 Scope[1]........SPP Staff (120 minutes)
   a. Data Inputs and Methodology
   b. Futures Assumptions
5. Closing Items........All

[1] Background Material Included

ITP Resource Expansion Methodology

ESWG

Kelsey Allen
June 3rd, 2015

Southwest Power Pool

Renewable Recommendation

- Survey
  - Non-Responders:
    - Calculate values based on state Mandate/Goal and information from Generation and/or Load Review
- Resource Plan
  - Designation of the new Other GI Firm resources to utilities by Staff for any potential Mandate or Goal shortfalls

ITP10/20 Resource Inclusion

Generation interconnection resources and facilities are included in the ITP models if they have an executed Interconnection Agreement (IA) that is not on suspension and minimal network upgrade costs. Generation capacity will automatically be designated to any utility once there is an executed transmission service agreement.

Proposed resources and facilities that have a high probability of going into service (i.e. If a planned generating resource does not have a TSR filed service agreement but does have a high probability of going into service) will be designated to a utility if it meets all of the following requirements:

ITP10/20 Resource Inclusion

- A Resource Addition Request (RAR) has been sent to SPP requesting the generation capacity be included into the ITP;
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA; and
- The generating resource will have firm contract for delivery in one or more forms:
  - The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts; or
  - The utility to be designated will own and operate the resource or has procured a Purchase Power Agreement (PPA) from the generation owner

ITP10/20 Resource Inclusion

- If a generating resource does not meet all the above requirements, a RAR for generation capacity to be included in a long-term ITP assessment can be made to ESWG on a case by case basis. ESWG will take into account the following, but not limited to, additional points:
  - A Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable
  - An RFP for the generating resource has been awarded, if applicable.

- All other resource expansion needs will be determined through the SPP resource planning process

Timeline

6/3 – Recommendation approval

6/3 – Solicit Resource Addition Requests (RAR)

6/10 – RAR due

6/11 – Post ESWG meeting materials

6/18 – Gen and load review/RAR approvals

Staff Recommendation

SPP Staff recommends the ESWG approve the proposed ITP resource inclusion methodology.

APPENDIX

Resource Expansion Methodology

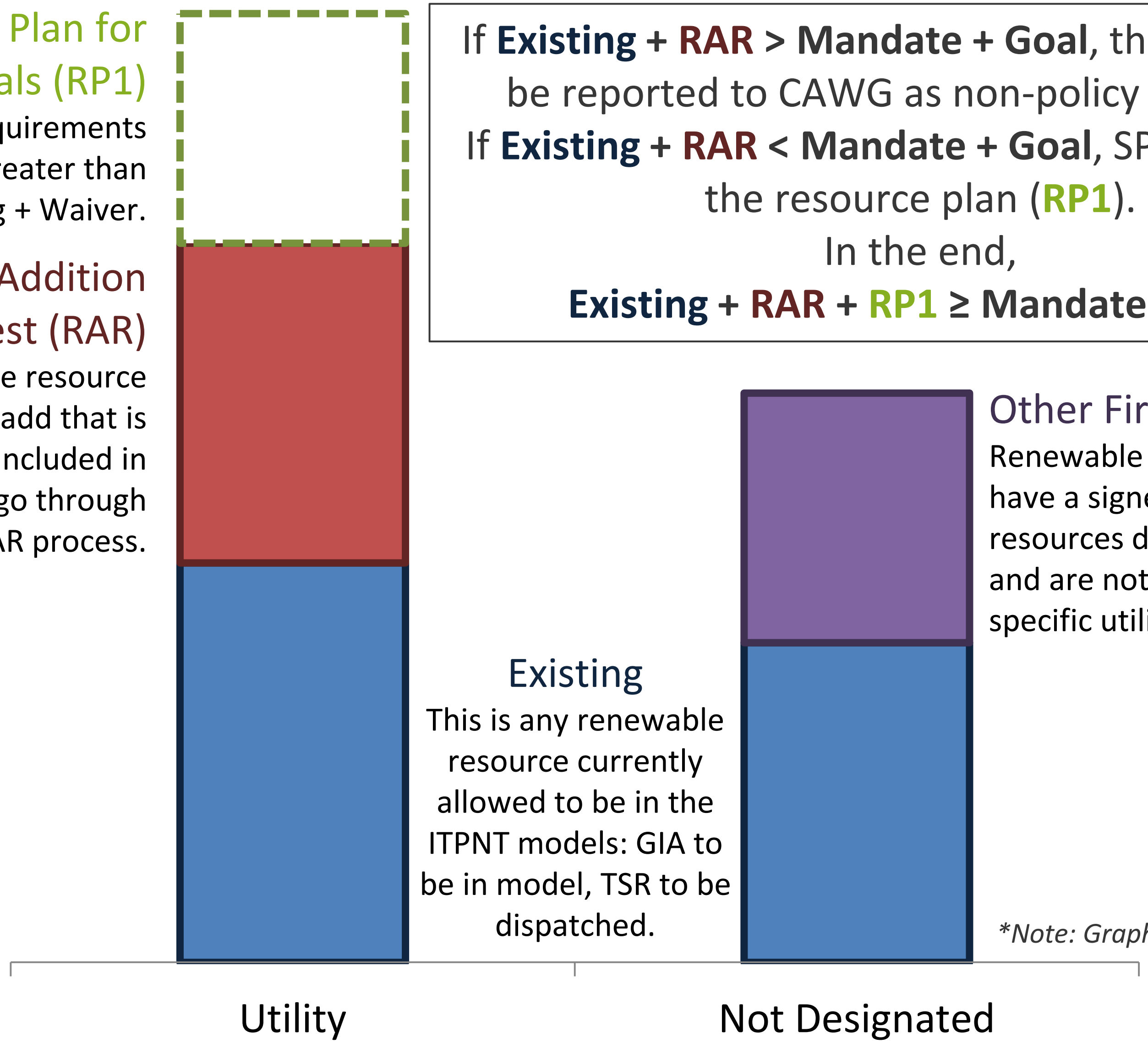
Resource Plan for Mandates/Goals (RP1)

These renewable requirements may or may not be greater than Existing + Waiver.

Resource Addition Request (RAR)

This is any renewable resource a utility would like to add that is not currently included in Existing. This will go through the RAR process.

If **Existing** + **RAR** > **Mandate** + **Goal**, the surplus will be reported to CAWG as non-policy resources.
If **Existing** + **RAR** < **Mandate** + **Goal**, SPP will add to the resource plan (**RP1**).
In the end,
Existing + **RAR** + **RP1** ≥ **Mandate** + **Goal**



Other Firm GI

Renewable resources that have a signed GIA. These resources do not have a TSR and are not assigned to a specific utility.

Existing

This is any renewable resource currently allowed to be in the ITPNT models: GIA to be in model, TSR to be dispatched.

**Note: Graph not to scale*

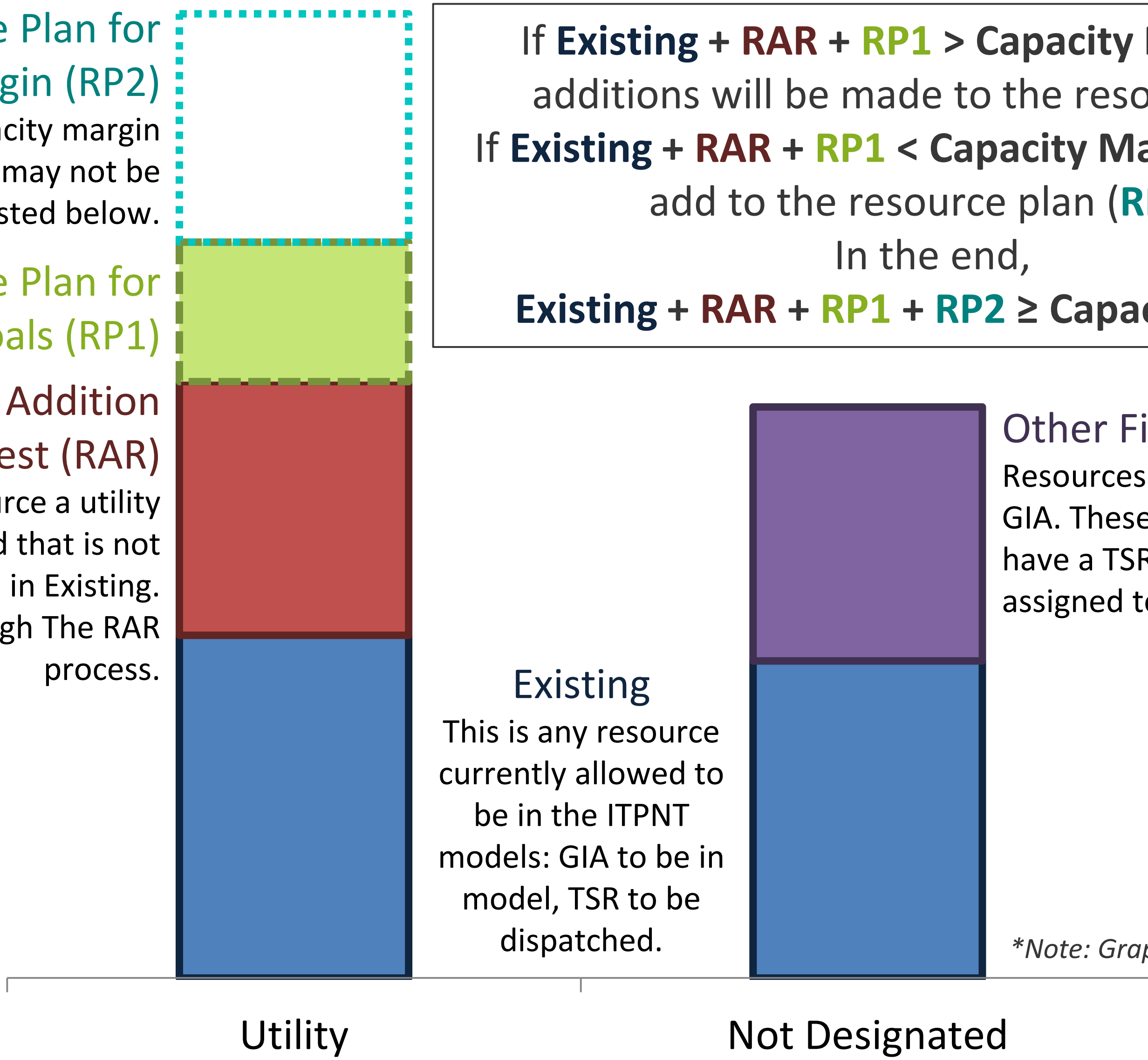
Resource Expansion Methodology

If **Existing** + **RAR** + **RP1** > **Capacity Margin**, no additions will be made to the resource plan.
If **Existing** + **RAR** + **RP1** < **Capacity Margin**, SPP will add to the resource plan (**RP2**).
In the end,
Existing + **RAR** + **RP1** + **RP2** ≥ **Capacity Margin**

Resource Plan for Capacity Margin (RP2)
The capacity margin requirement may or may not be met by resources listed below.

Resource Plan for Mandates/Goals (RP1)

Resource Addition Request (RAR)
This is any resource a utility would like to add that is not currently included in Existing. This will go through The RAR process.



Existing
This is any resource currently allowed to be in the ITPNT models: GIA to be in model, TSR to be dispatched.

Other Firm GI
Resources that have a signed GIA. These resources do not have a TSR and are not assigned to a specific utility.

**Note: Graph not to scale*

Additional Block Details

- Other Firm GI
  - Resources with signed GIAs
    - Not in ITPNT models
    - On schedule with minimal network upgrade costs
  - Staff-driven
  - Results in non-designated resources
  - Potentially leverage for RP1

Service Status	Designated?	Wind Capacity (MW)	Non-Wind Capacity (MW)
Existing	No	238.5	24.2
Projected	No	4040.4	324.5

Table shows resources that could have been added to the 2015 ITP10 (less Other Renewables) today with the proposed methodology.

Additional Block Details

- Resource Addition Request (RAR)
  - Leverage ITPNT waiver process
    - Add ESWG vetting
    - Process defined in ITP Manual Section 3.3.1.2
  - Stakeholder-driven
  - Results in utility designation
- Suggested Changes to process
  - Remove TSR requirement
  - Required- RAR for publically announced resource expansion
  - Optional- RAR for non-public resource expansion

2017 ITP10 Scope

SPP Staff

June 3rd, 2015

Data Inputs & Study Methodology

- Load & Gen review
- Renewable survey
- System topology
- Fuel prices
- Emissions price
- DC Ties
- Hourly Load Profiles
- Hourly Renewable Profiles
- Resource plan
  - Capacity accreditation/margin
  - Prototypes

- Siting
- GOF
- Define constraints
- Benchmarking
- Needs Assessment
- Project Selection
- Project Grouping
- Portfolio Consolidation
- Benefit Metrics
- Sensitivities

*Complete Discussing Today Reference

2017 ITP10 Data Inputs

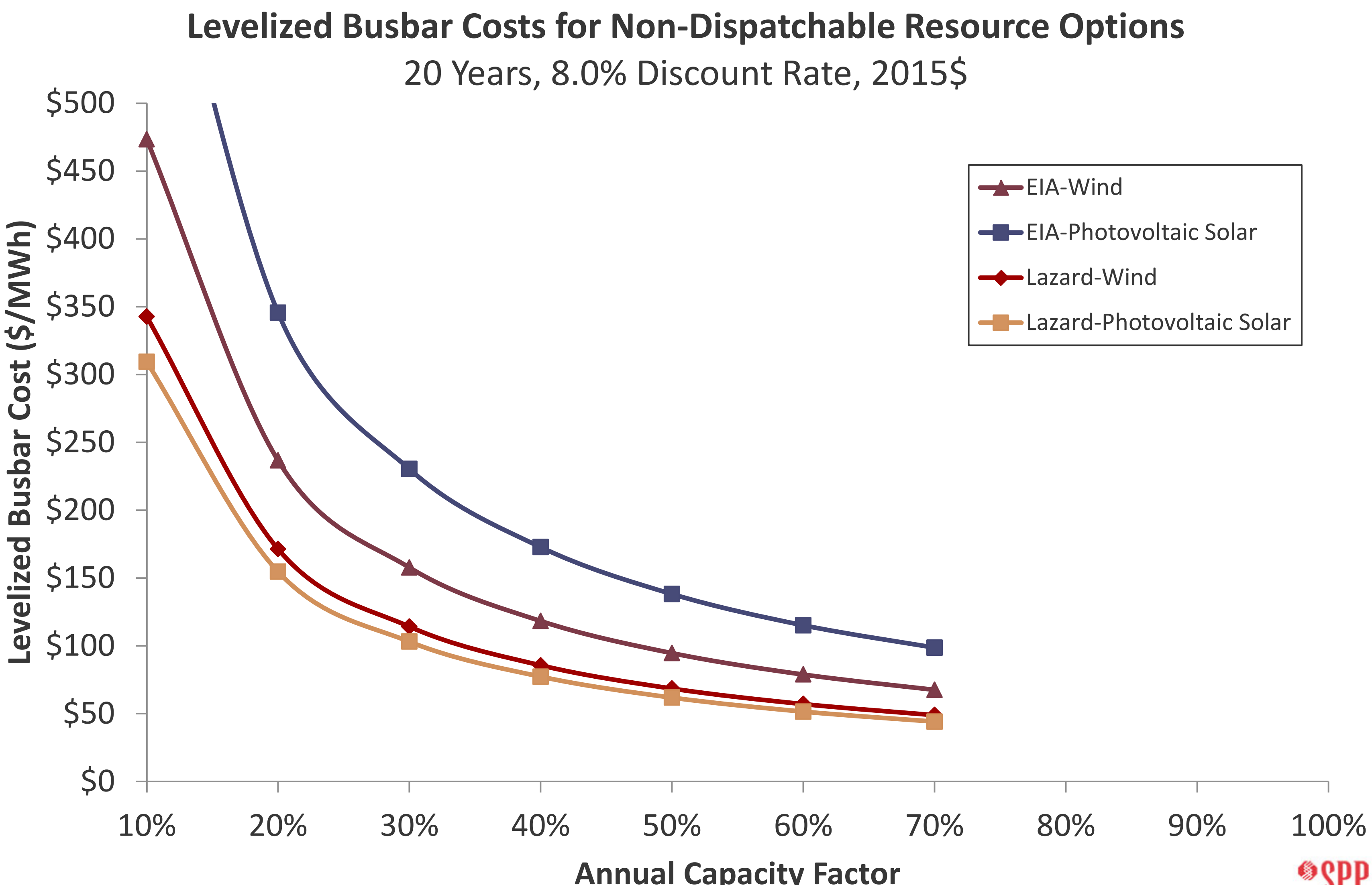
GENERATION PROTOTYPES

Prototype Data Source Options

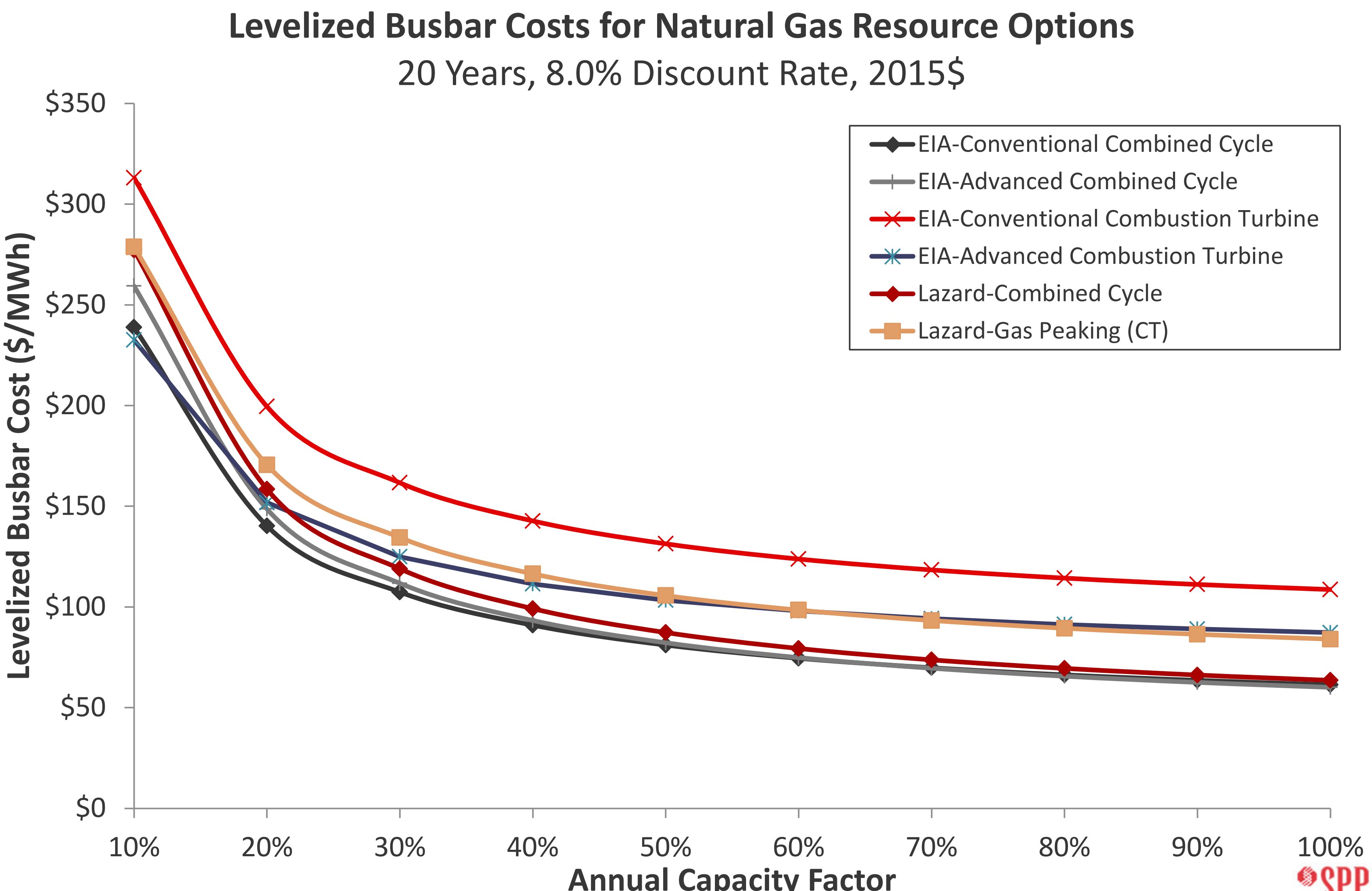
- EIA Annual Energy Outlook (AEO) Report
  - Used in past ITP studies
  - AEO 2015 data available in June
- Lazard Levelized Cost of Energy Analysis – Version 8.0
  - September 2014

Generation Type	Data Source	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA AEO2014	400	1,073	3.44	16.15	6,430
	Lazard	550	1,006-1,318	3.50-2.00	6.20-5.50	6,700-6,900
Combustion Turbine (CT)	EIA AEO2014	210	673	10.37	7.04	9,750
	Lazard	216-103	800-1000	4.70-7.50	5.00-25.00	10,300-9,000
Coal	EIA AEO2014	1,300	3,073	4.70	32.76	8,800
	Lazard	600	3,000-8,400	2.00-5.00	40.00-80.00	8,750-12,000
Nuclear	EIA AEO2014	2,234	5,779	2.25	98.00	10,464
	Lazard	1,100	5,385-8,199	0.25-0.75	95.00-115.00	10,450
Wind	EIA AEO2014	100	2,317	0.00	41.55	N/A
	Lazard	100	1,400-1,800	0.00	35.00-40.00	N/A
Solar PV (Utility Scale)	EIA AEO2014	150	3,744	0.00	25.94	N/A
	Lazard	10	1,750-1,500	0.00	20.00-13.00	N/A

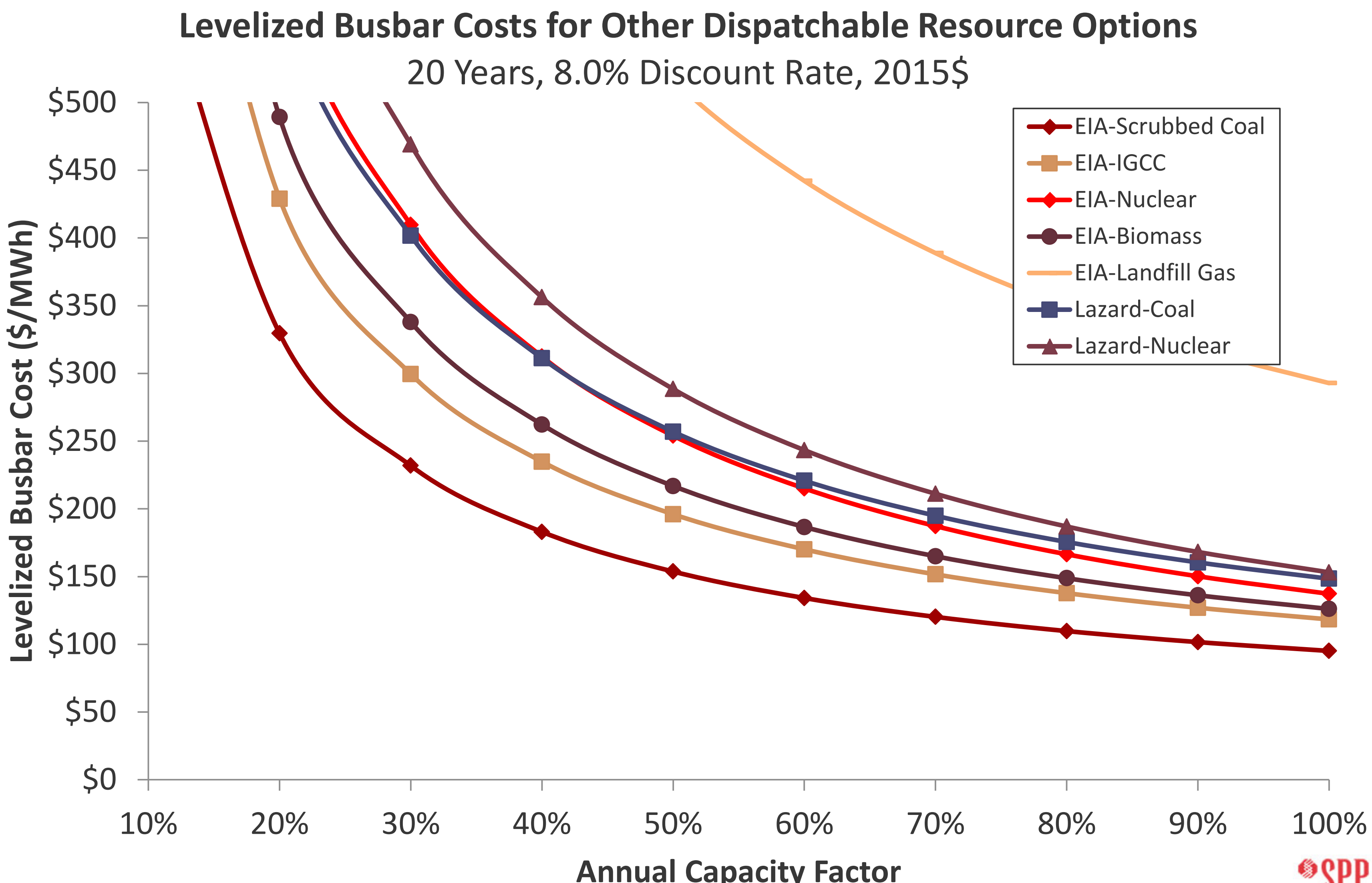
Busbar Curves – Renewable Units



Busbar Curves – Gas Units



Busbar Curves – Other Conventional Units



Prototypes Recommendation

SPP Staff recommends the ESWG approve using the Lazard data set for generation prototypes

2017 ITP10 Data Inputs

WIND CAPACITY FACTORS

Wind Capacity Factors

- 2015 ITP10 Approach
  - Use existing 2005 NREL EWITS profiles, and increase capacity factors of new wind farms by 15%
- Staff Recommended Approach for 2017 ITP10
  - Use NREL 2012 WIND toolkit dataset

Wind Capacity Factors – 2012 dataset

- This newer data was not yet available during 2015 ITP10 modeling
- NREL WIND toolkit includes 2007 – 2012 datasets, we propose to utilize the 2012 data
- Higher capacity factors that reflect technological advances
- More comprehensive, higher resolution
- Corrects some smaller errors that were present in the 2004 – 2006 datasets
- 100m hub heights, Class I, II, or III, depending on the annual average wind speed

Recommendation

- **SPP Staff recommends the ESWG approve the use of NREL 2012 datasets for modeling hourly profiles of wind in the 2017 ITP10 study**

Benchmarking Recommendation

- Assess 2014-2015 Operations Data
- Benchmarking data
  - Capacity factor by unit type
  - Generation by unit type
  - Operating & spinning reserve
  - System LMPs
- Hurdle Rates
  - Reassess
  - Flowgate loading
  - Zonal production cost
  - Generation dispatch order
  - Zonal purchases & sales

Define Constraints - TWG

- NERC Book of Flowgates
- Additional constraints added using PAT
- Contingencies 100 kV and above in SPP and first-tier
- Monitored elements 100 kV and above in SPP and first-tier
- Unless other information is available, each constraint’s rating will be selected based upon the applicable Rating A (normal rating) or Rating B (emergency rating) in the power flow model

Needs Assessments Recommendation

- Economic, Policy, Reliability conducted in parallel
- Policy Assessment
  - Shortfall in the achievement of renewable requirements
- Economic Assessment
  - The SCED will solve nodal LMPs
  - Constraints ranked based on flowgate congestion cost
  - Up to 25 constraints based upon the ranking will be identified as economic need per future

Solution Development Recommendation

- Solicit stakeholders for solutions for all identified needs
- Policy projects: mitigate renewable curtailment to meet the regulatory/statutory mandates and goals
- Economic projects: B/C ≥ 0.9 for one year
- Seams projects
  - Identified based on benefits to other regions
  - For seams projects with MISO, assign cost based on the APC benefits received by each region, reducing MISO benefits by 20%
  - 80/20 cost sharing with all other regions

Phase 1 – Individual Project Testing Recommendation

- Projects will move on to Phase 2 for further testing if they meet the following criteria
  - The project must meet the need for which it was submitted and
    - Projects to address economic needs must provide a 1-year B/C ratio greater than 0.75 by reducing the congestion.
    - Policy Projects must allow the utilities to meet the regulatory/statutory mandates and goals.

Project Grouping Methodology Recommendation

- Reliability, policy, and economic projects will be combined into project groupings for each future and evaluated for redundancies
- Project groupings will be developed considering:
  - Project's Phase 1 performance
  - 70% congestion relief per need to address locality of constraint and solution
- Groupings per Future:
  - Cost Effective
  - Highest Gross APC benefit
  - Highest Net APC benefit
  - Multi-Variable Grouping

Phase 2 – Combined Project Testing Recommendation

- **Cost-Effective Rank - Total Project Cost / Flowgate Congestion Cost Mitigated**
- **Highest Gross APC benefit - Highest APC benefit, not considering the cost of the projects**
  - Projects will be ranked based on the gross benefit when considering mitigation of each individual constraint
- **Highest Net APC benefit - The cost of the projects will be subtracted from the APC benefit provided**
  - Projects will be ranked based on the net benefit when considering mitigation of each individual constraint
- **Multi-Variable Grouping (Optional) – Allows SPP staff to layer multiple criteria. The experience gained from analyzing projects for the first three groups will be utilized to determine projects**

Project Staging criteria Recommendation

- Single project classification
  - Economic – based on a linear interpolation of B/C ratios from 2020 to 2025
  - Reliability - based on linear interpolation of thermal loadings from 2020 to 2025
  - Policy – staged to meet renewable requirement
- Multiple project classification
  - Staged to meet the earliest need date established through the Single Project Classification
  - Economic projects must cross the 1.0 B/C ratio threshold

Benefit Metrics Recommendation

Metric Description
APC Savings
Value of Replacing Previously Approved Projects
Reduced Losses
Reduced Capacity Costs
Reduction of Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs

2017 ITP10 Data Inputs

FUTURES ASSUMPTIONS

Carbon Cost Adder

Limiting emissions

- driving dispatch, which
- changes resource expansion
- $36/ton adder in 2015 ITP10 Future 3
- $45/ton adder in SPP regional CPP study

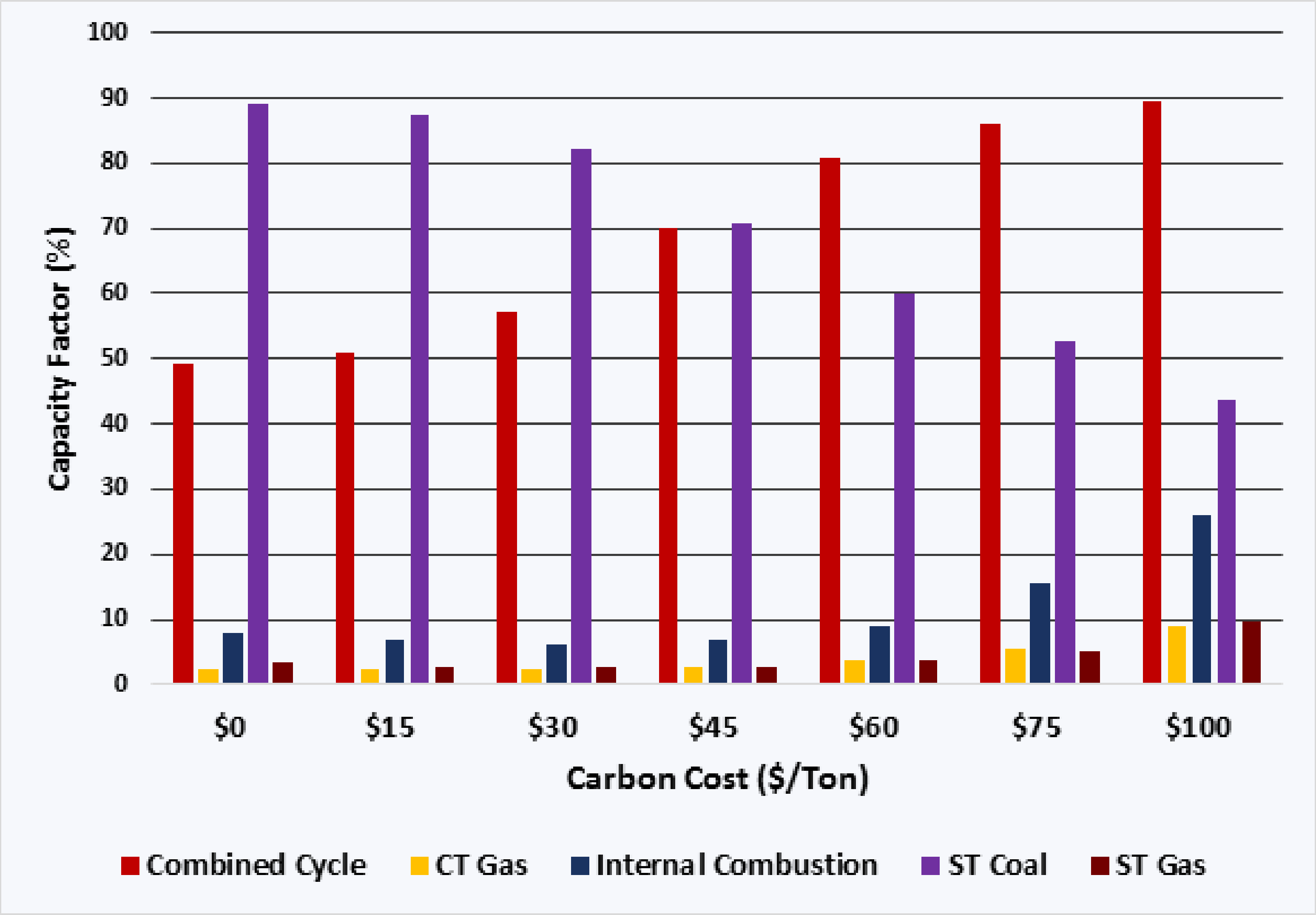
Future 3

- Zero CO_2 emission limits

Futures 1 and 2

- Regional CO_2 price
- State by State CO_2 price
- Inter-regional Impacts
  - Tier 1 CO_2 price?
  - Hurdle Rates?

SPP CPP Carbon Cost Analysis



EPA Social Cost of Carbon

The table below presents the most recent SCC estimates (PDF, 22 pp, 780 KB) (updated in 2013) for certain years.

Social Cost of CO_2, 2015-2050 [a] (in 2011 Dollars)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$12	$39	$61	$116
2020	$13	$46	$68	$137
2025	$15	$50	$74	$153
2030	$17	$55	$80	$170
2035	$20	$60	$85	$187
2040	$22	$65	$92	$204
2045	$26	$70	$98	$220
2050	$28	$76	$104	$235

[a] The SCC values are dollar-year and emissions-year specific.

http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

SEPTEMBER 2014

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 8.0

LAZARD

Introduction

Lazard's Levelized Cost of Energy Analysis ("LCOE") addresses the following topics:

- Comparative "levelized cost of energy" for various technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel costs, geography and cost of capital, among other factors
- Comparison of the implied cost of carbon abatement given resource planning decisions for various generation technologies
- Illustration of how the cost of utility-scale and rooftop solar-produced energy compares against generation rates in large metropolitan areas of the United States
- Illustration of utility-scale and rooftop solar versus peaking generation technologies globally
- Illustration of how the costs of utility-scale and rooftop solar and wind vary across the United States, based on average available resources
- Forecast of rooftop solar levelized cost of energy through 2017
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Decomposition of the levelized cost of energy for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense, and fuel cost, as relevant
- Considerations regarding the usage characteristics and applicability of various generation technologies, taking into account factors such as location requirements/constraints, dispatch capability, land and water requirements and other contingencies
- Summary assumptions for the various generation technologies examined
- Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies

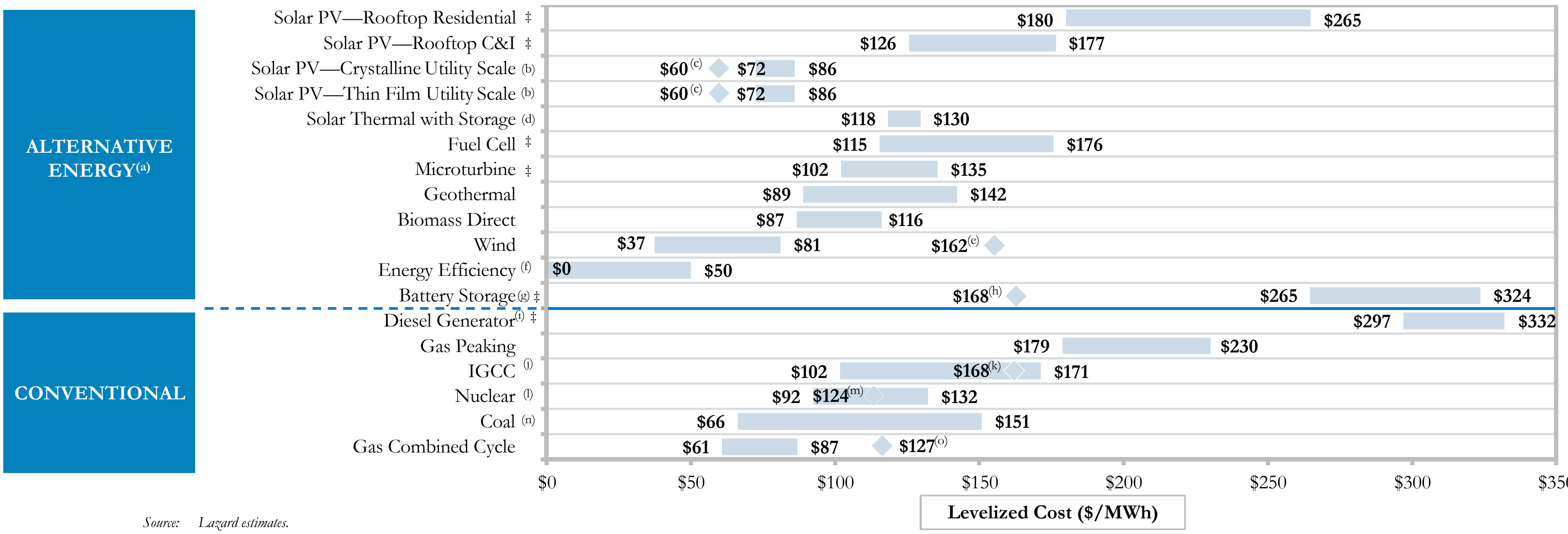
Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.)

While prior versions of this study have presented the LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present the LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies"

Note: This study has been prepared by Lazard for general informational purposes only, and it is not intended to be, and should not be construed as, financial or other advice.

Unsubsidized Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies)



Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Assumes Powder River Basin coal price of $1.99 per MMBtu and natural gas price of $4.50 per MMBtu. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

(a) Analysis excludes integration costs for intermittent technologies. A variety of studies suggest integration costs ranging from $2.00 to $10.00 per MWh.

(b) Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(c) Diamonds represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

(d) Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

(e) Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.

(f) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely. Estimates involving demand response may fail to account for opportunity cost of foregone consumption.

(g) Indicative range based on current stationary storage technologies; assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

(h) Diamond represents estimated implied levelized cost for "next generation" storage in 2017; assumes capital costs of $300/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% and fixed O&M costs of $5.00 per KWh installed per year.

(i) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

(j) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

(k) Represents estimate of current U.S. new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.

(l) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

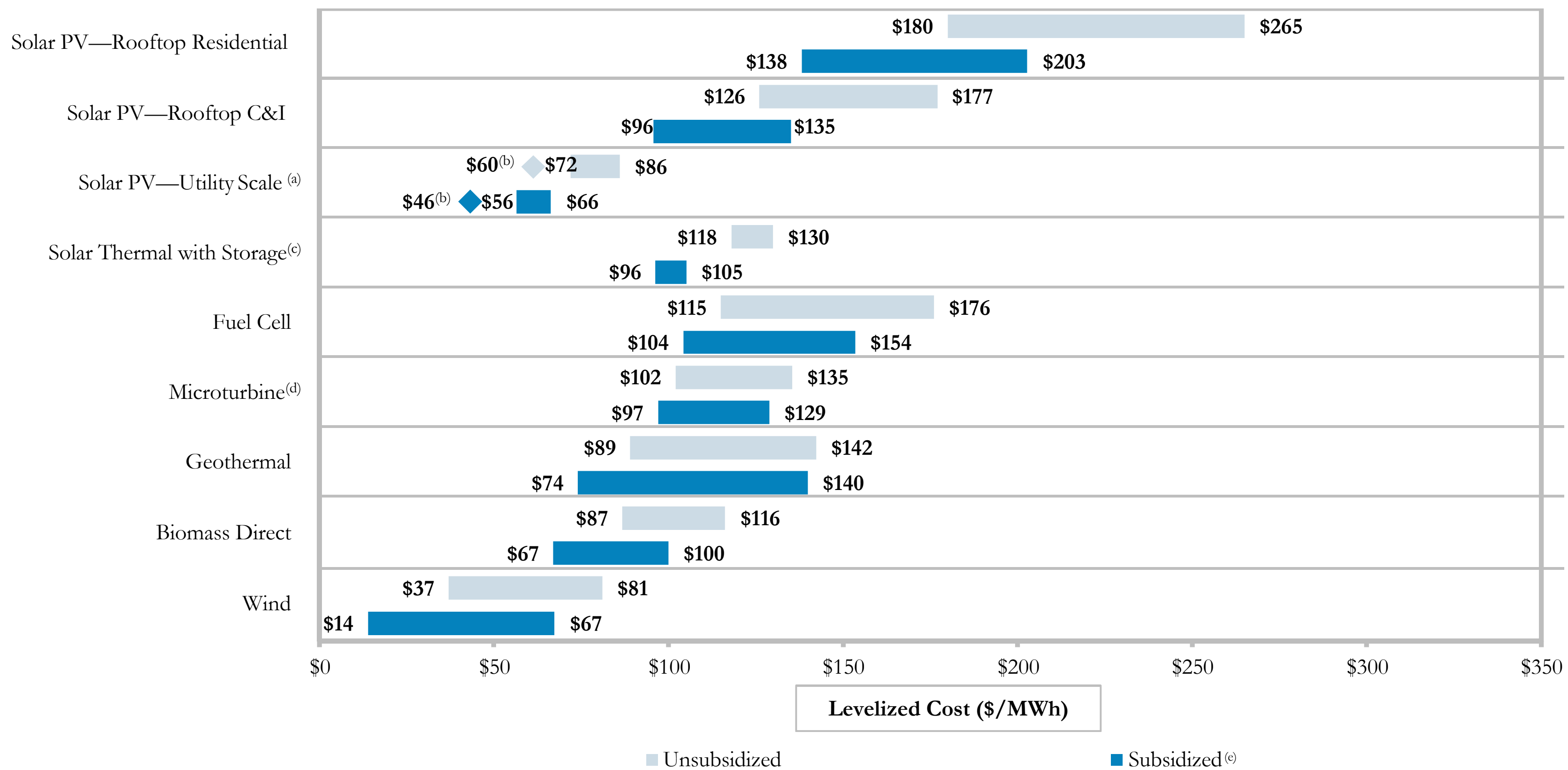
(m) Represents estimate of current U.S. new nuclear construction.

(n) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

(o) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies

U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are, generally, currently important in all regions); while some Alternative Energy generation technologies have achieved notional "grid parity" under certain conditions (e.g., best-in-class wind/solar resource), such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies)

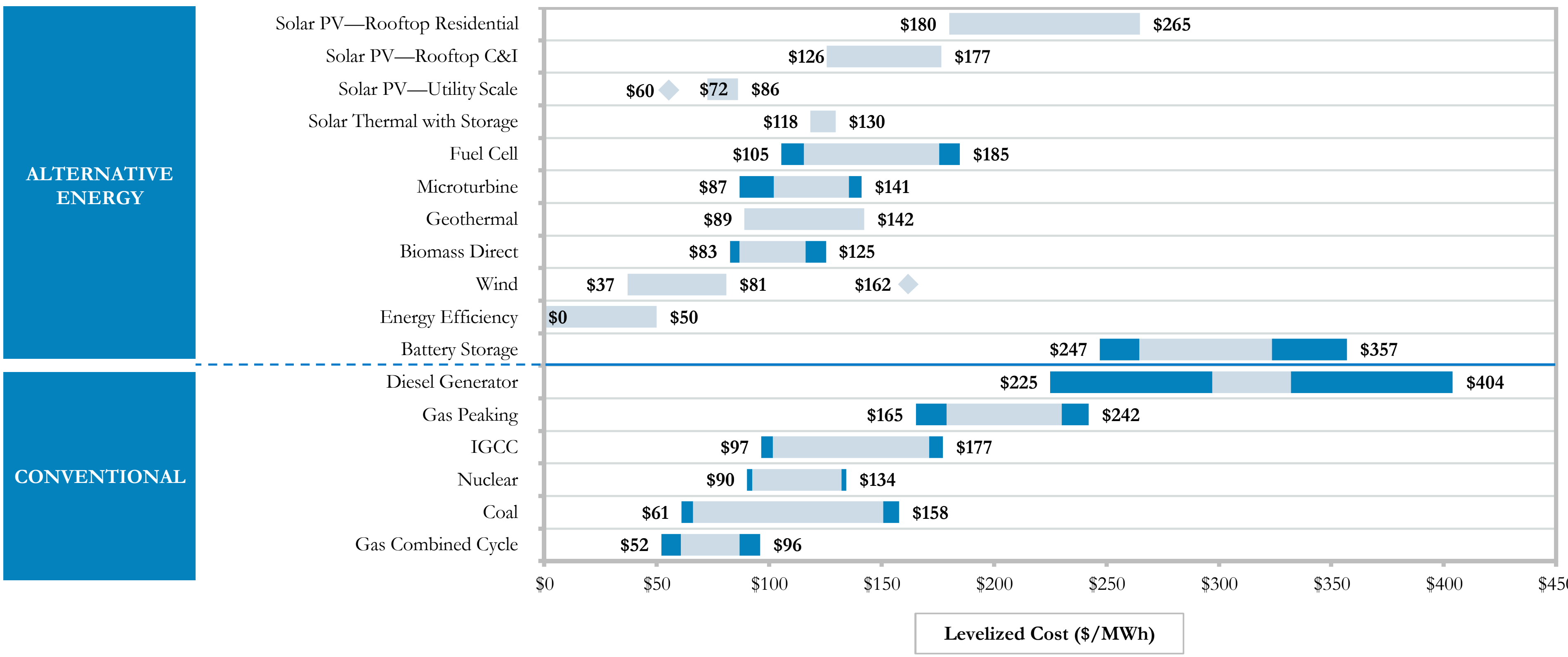


Source: Lazard estimates.

(a) Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW fixed-tilt installation in high insolation jurisdiction (e.g., Southwest U.S.).
(b) Diamonds represent estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.
(c) Low end represents concentrating solar tower with 18-hour storage. High end represents concentrating solar tower with 10-hour storage capability.
(d) Reflects 10% Investment Tax Credit. Capital structure adjusted for lower Investment Tax Credit; assumes 50% debt at 8.0% interest rate, 20% tax equity at 12.0% cost and 30% common equity at 12.0% cost.
(e) Except where noted, reflects 30% Investment Tax Credit. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 12.0% cost and 20% common equity at 12.0% cost.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



Source: Lazard estimates.
Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations.

Cost of Carbon Abatement Comparison

As policymakers consider the best and most cost-effective ways to limit carbon emissions (including in the U.S., in respect of Section 111(d) regulations), they should consider the implicit costs of carbon abatement of various Alternative Energy generation technologies; an analysis of such implicit costs suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost effective way of limiting carbon emissions; rooftop solar and solar thermal remain expensive, by comparison

- **Such observation does not take into account potential social and environmental externalities or reliability-related considerations**

		CONVENTIONAL GENERATION			ALTERNATIVE ENERGY RESOURCES			
	Units	Coal[b]	Gas Combined Cycle	Nuclear	Wind	Solar PV Rooftop	Solar PV Utility Scale[c]	Solar Thermal[d] with Storage
Capital Investment/KW of Capacity[a]	$/kW	$3,000	$1,006	$5,385	$1,400	$3,500	$1,750	$9,800
Total Capital Investment	**$mm**	**$1,800**	**$805**	**$3,339**	**$1,498**	**$8,505**	**$3,255**	**$6,860**
Memo: Total ITC/PTC Tax Subsidization	$mm	––	—	—	$449	$2,552	$977	$2,058
Facility Output	**MW**	**600**	**800**	**620**	**1,070**	**2,430**	**1,860**	**700**
Capacity Factor	%	93%	70%	90%	52%	23%	30%	80%
Effective Facility Output	**MW**	**558**	**558**	**558**	**558**	**558**	**558**	**558**
MWh/Year Produced[e]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$66	$61	$92	$37	$180	$72	$118
Total Cost of Energy Produced	**$mm/yr**	**$324** ②	**$298**	**$452**	**$183**	**$880**	**$354** ①	**$579**
Carbon Emitted	mm Tons/yr	4.54	1.92	—	––	—	––	––
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		––	2.62	4.54	4.54	4.54	4.54 ③	4.54
vs. Gas		––	—	1.92	1.92	1.92	1.92	1.92
Difference in Total Energy Cost	$mm/yr							
vs. Coal		––	($26)	$128	($141)	$557	$31 ④	$255
vs. Gas		––	—	$154	($115)	$582	$57	$281
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		––	($10)	$28	($31)	$123	$7 ⑤	$56
vs. Gas		––	—	$80	($60)	$304	$30	$147

Source: Lazard estimates.

Note: Does not reflect production tax credit or investment tax credit. Assumes 2014 dollars, 20 – 40 year economic life, 40% tax rate and 5 – 40 year tax life. Assumes 2.5% annual escalation for O&M costs and fuel prices. Inputs for each of the various technologies are those associated with the low end levelized cost of energy.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) Based on advanced supercritical pulverized coal. Does not incorporate carbon capture and compression.

(c) Represents single-axis tracking.

(d) Low end represents concentrating solar tower with 18-hour storage capability.

(e) All facilities sized to produce 4,888 GWh/yr.

Illustrative Implied Carbon Abatement Cost Calculation:

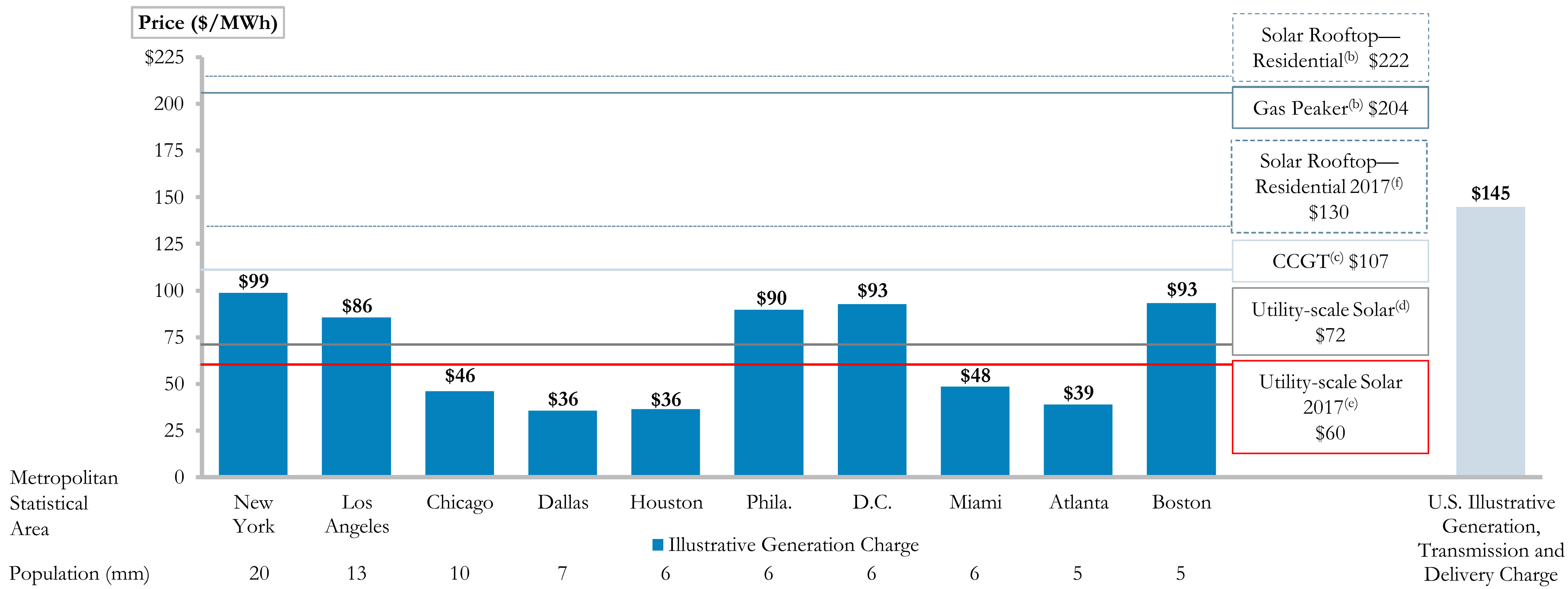
④ Difference in Total Energy Cost vs. Coal = ① – ②
= $354 mm/yr (solar) – $324 mm/yr (coal) = $31 mm/yr

⑤ Implied Abatement Cost vs. Coal = ④ ÷ ③
= $31 mm/yr ÷ 4.54 mm Tons/yr = $7/Ton

Generation Rates for the 10 Largest U.S. Metropolitan Areas[(a)]

Setting aside the legislatively-mandated demand for solar and other Alternative Energy resources, utility-scale solar is becoming a more economically viable peaking energy product in many areas of the U.S. and, as pricing declines, could become economically competitive across a broader array of geographies

- **Such observation does not take into account potential social and environmental externalities or reliability-related considerations**

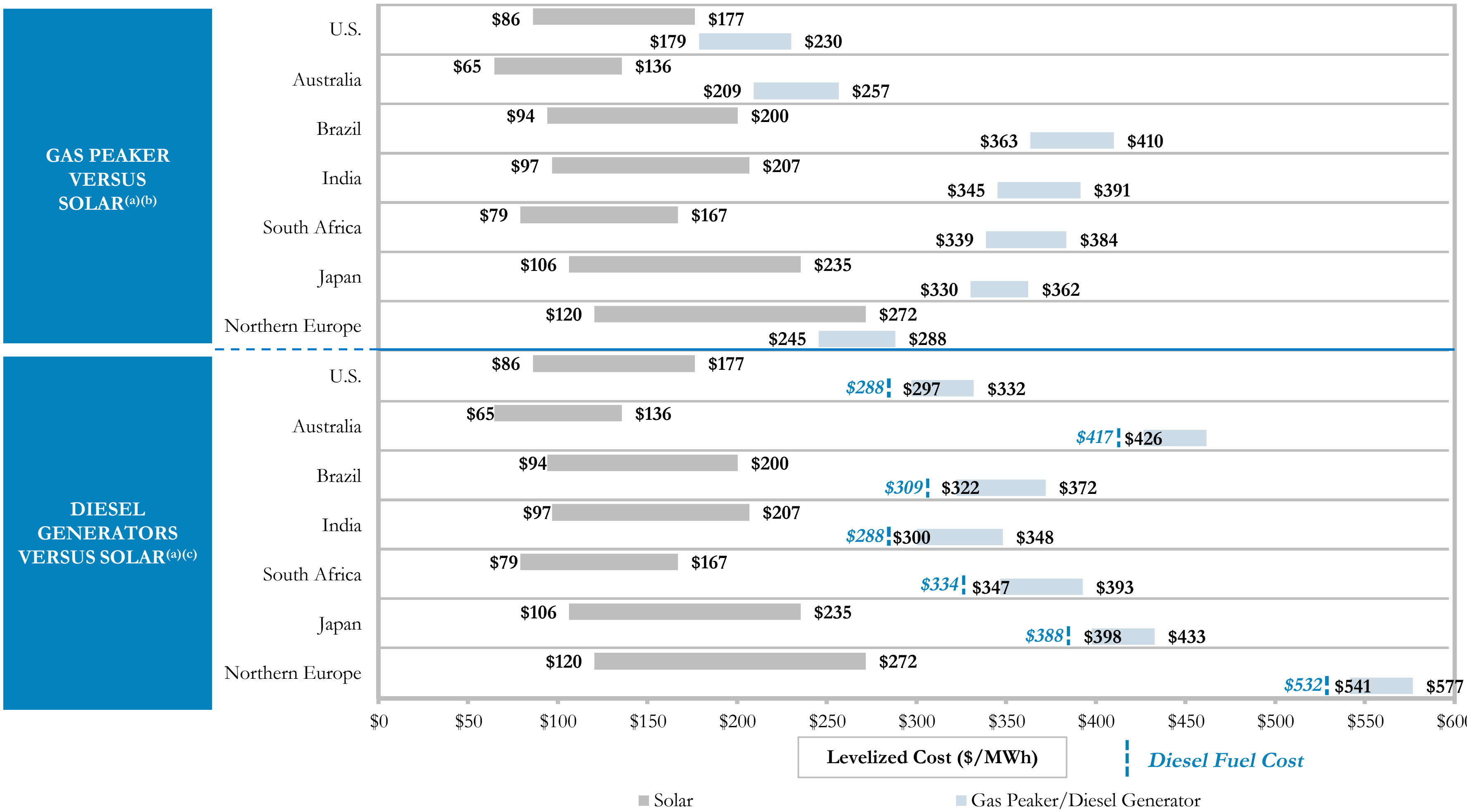


	New York	Los Angeles	Chicago	Dallas	Houston	Phila.	D.C.	Miami	Atlanta	Boston
Population (mm)	20	13	10	7	6	6	6	6	5	5
Cumulative % of U.S. population[(g)]	6%	11%	14%	16%	18%	20%	22%	23%	25%	27%

Source: *EEI, Ventyx.*
Note: Actual delivered generation prices may be higher, reflecting historical composition of resource portfolio.
(a) Defined as 10 largest Metropolitan Statistical Areas per the U.S. Census Bureau for a total population of 83 million.
(b) Represents an average of the high and low levelized cost of energy.
(c) Assumes 25% capacity factor.
(d) Represents low end of utility-scale solar. Excludes investment tax credit.
(e) Represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system. Excludes investment tax credit.
(f) Represents estimated implied levelized cost of energy in 2017, assuming $2.20 per watt (average of high and low).
(g) Represents 2013 census data.

Solar versus Peaking Capacity—Global Markets

Solar PV can be an attractive resource relative to gas and diesel-fired peaking in many parts of the world due to high fuel costs; without storage, however, solar lacks the dispatch characteristics of conventional peaking technologies



Source: *World Bank, IHS Waterborne LNG, Department of Energy of South Africa, Sydney and Brisbane Hub Trading Prices and Lazard estimates.*

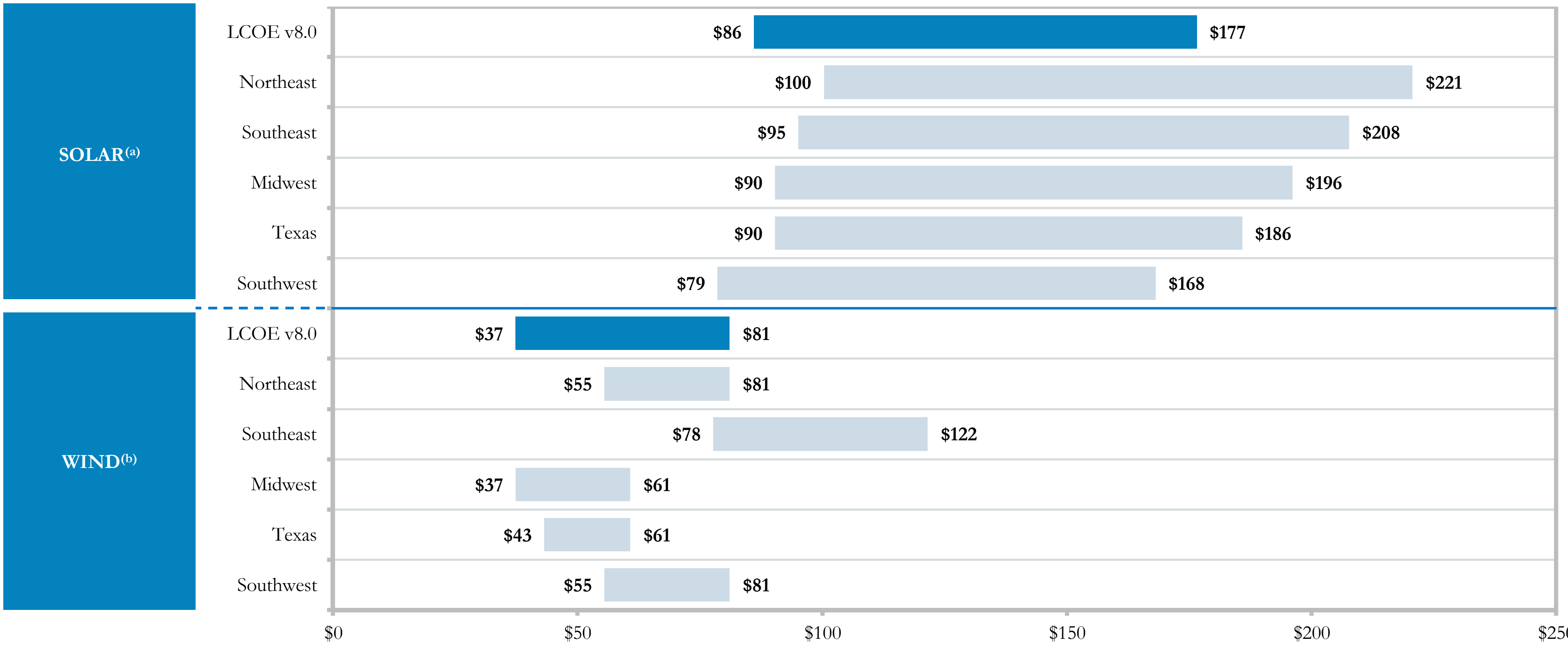
(a) Low end assumes a solar fixed-tilt utility-scale system with per watt capital costs of $1.50. High end assumes a solar rooftop C&I system with per watt capital costs of $3.00. Solar projects assume capacity factors of 26% – 28% for Australia, 25% – 27% for Brazil, 23% – 25% for India, 27% – 29% for South Africa, 15% – 17% for Japan and 13% – 15% for Northern Europe. Equity IRRs of 12% are assumed for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa; assumes cost of debt of 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(b) Assumes natural gas prices of $7 for Australia, $16 for Brazil, $15 for India, $15 for South Africa, $17 for Japan and $10 for Northern Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10%.

(c) Diesel assumes high end capacity factor of 30% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization, O&M cost of $15 per KW/year, heat rate of 10,000 Btu/KWh and total capital costs of $500 to $800 per KW of capacity. Assumes diesel prices of $5.80 for Australia, $4.30 for Brazil, $4.00 for India, $4.65 for South Africa, $5.40 for Japan and $7.40 for Northern Europe (all in U.S.$ per gallon).

Wind and Solar Resource—U.S. Regional Sensitivity (Unsubsidized)

The availability of wind and solar resource has a meaningful impact on the levelized cost of energy for various regions of the United States. This regional analysis varies capacity factors as a proxy for resource availability, while holding other variables constant. There are a variety of other factors (e.g., transmission, back-up generation/system reliability costs, labor rates, permitting and other costs) that would also impact regional costs

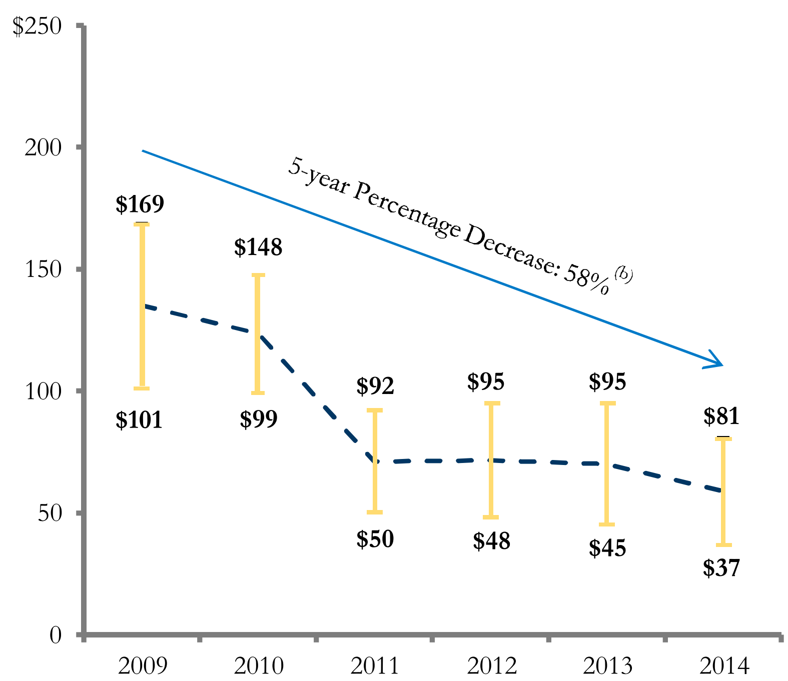


Source: Lazard estimates.
Note: Assumes solar capacity factors of 16% – 18% for the Northeast, 17% – 19% for the Southeast, 18% – 20% for the Midwest, 19% – 20% for Texas and 21% – 23% for the Southwest. Assumes wind capacity factors of 30% – 35% for the Northeast, 20% – 25% for the Southeast, 40% – 52% for the Midwest, 40% – 45% for Texas and 30% – 35% for the Southwest.
(a) Low end assumes a solar fixed-tilt utility-scale system with per watt capital costs of $1.50. High end assumes a solar rooftop C&I system with per watt capital costs of $3.00.
(b) Assumes an onshore wind generation plant with capital costs of $1.40 – $1.80 per watt.

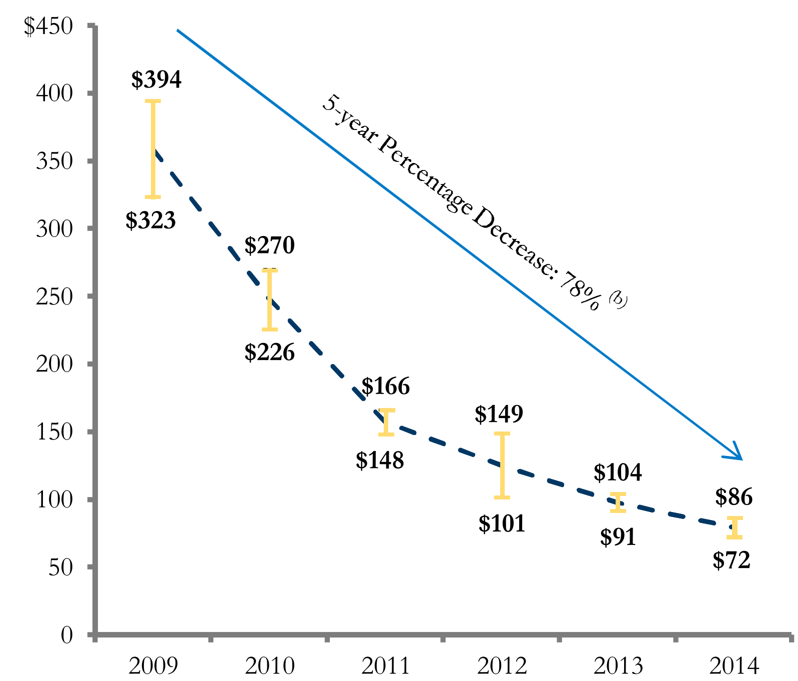
Levelized Cost of Energy—Wind/Solar PV (Historical)

Over the last five years, wind and solar PV have become increasingly cost-competitive with conventional generation technologies, on an unsubsidized basis, in light of material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors

WIND LCOE



SOLAR PV LCOE [(a)]



LCOE   LCOE Range

Source: Lazard estimates.

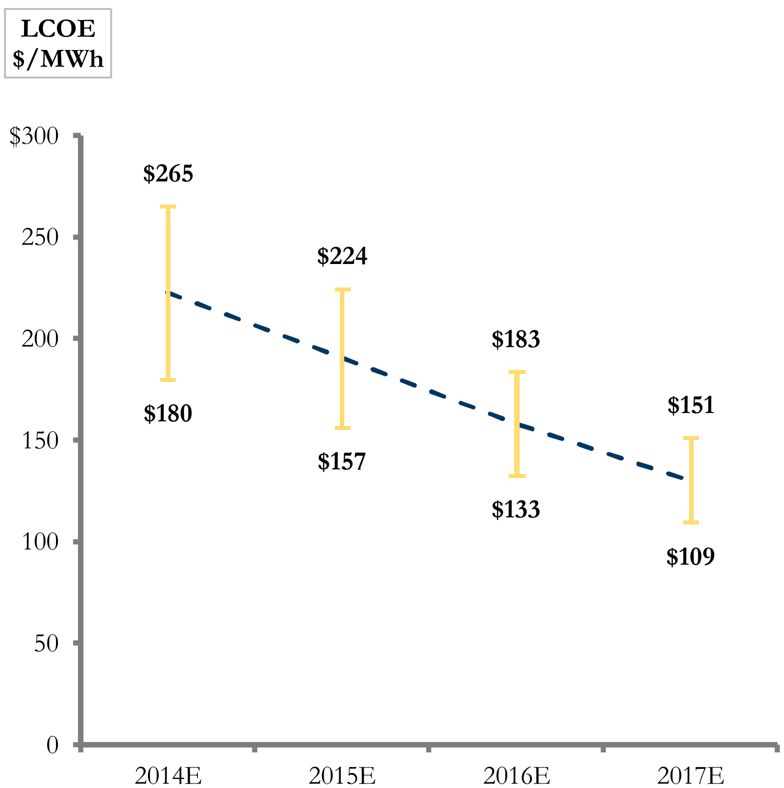
(a) Represents LCOE range of utility-scale crystalline solar PV. High end represents fixed installation, while low end represents single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.).

(b) Represents average percentage decrease of high and low of LCOE range.

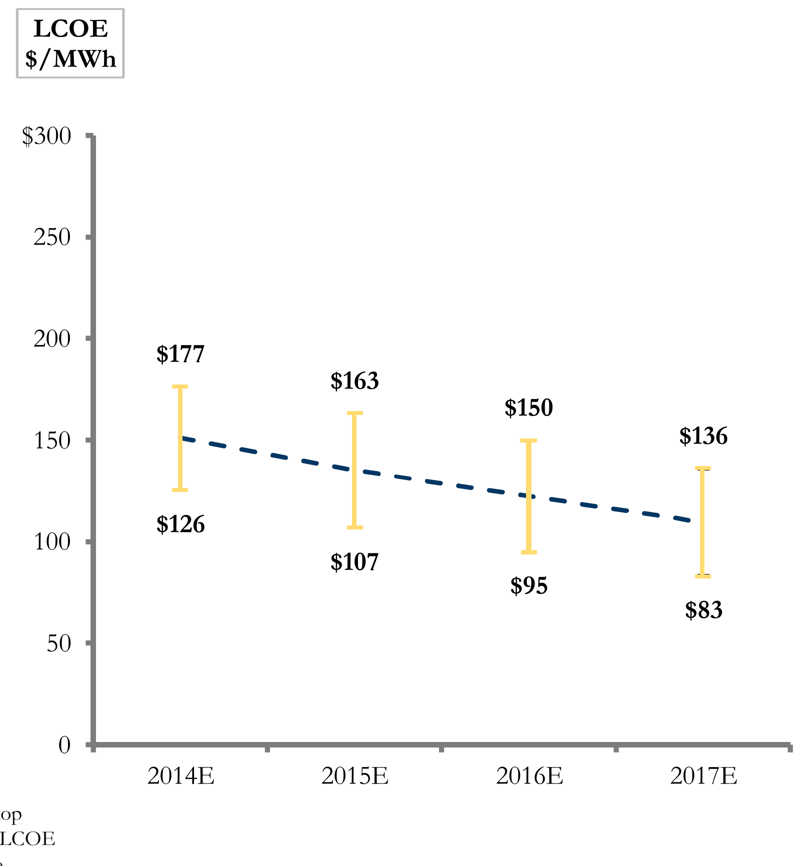
Levelized Cost of Energy—Rooftop Solar (Forecasted)

Rooftop solar has benefited from the rapid decline in price of both panels and key balance-of-system components (e.g., inverters, racking, etc.); while the small-scale nature and added complexity of rooftop installation limit cost reduction levels (vs. levels observed in utility-scale applications), more efficient installation techniques, lower costs of capital and improved supply chains will contribute to a lower rooftop solar LCOE over time

ROOFTOP RESIDENTIAL LCOE[(a)]



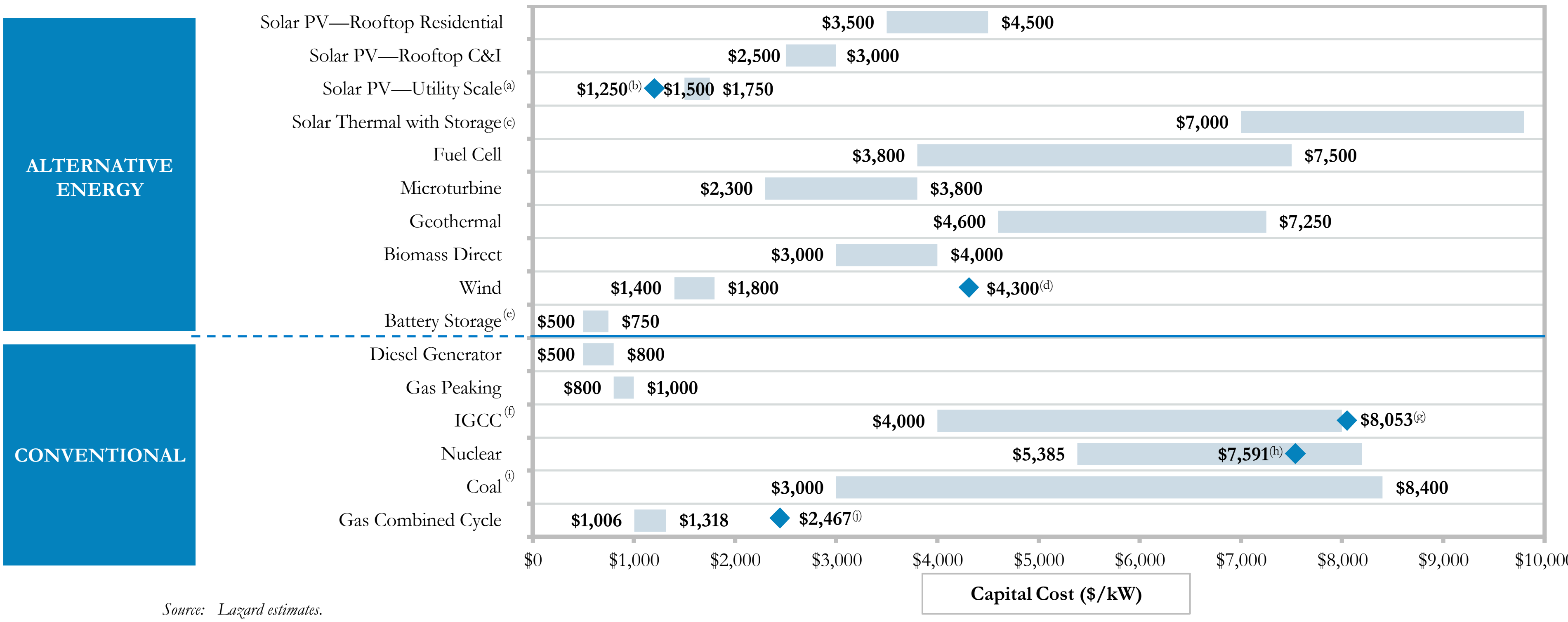
ROOFTOP C&I LCOE[(b)]



Source: Lazard estimates, BNEF and Wall Street research.
Note: Assumes capacity factors of 20% – 23%.
(a) Represents total high-end capital costs per watt of $4.50, $3.75, $3.00 and $2.40 and total low-end capital costs per watt of $3.50, $3.00, $2.50 and $2.00 over 2014 – 2017, respectively. Assumes fixed O&M of $25 – $30 per kW/year for 2014 – 2017.
(b) Represents total high-end capital costs per watt of $3.00, $2.75, $2.50 and $2.25 and total low-end capital costs per watt of $2.50, $2.10, $1.85 and $1.60 over 2014 – 2017, respectively. Assumes fixed O&M of $13 – $20 per kW/year for 2014 – 2017.

Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of some conventional generation technologies (e.g., gas), declining costs for many Alternative Energy generation technologies, coupled with rising long-term construction and uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies

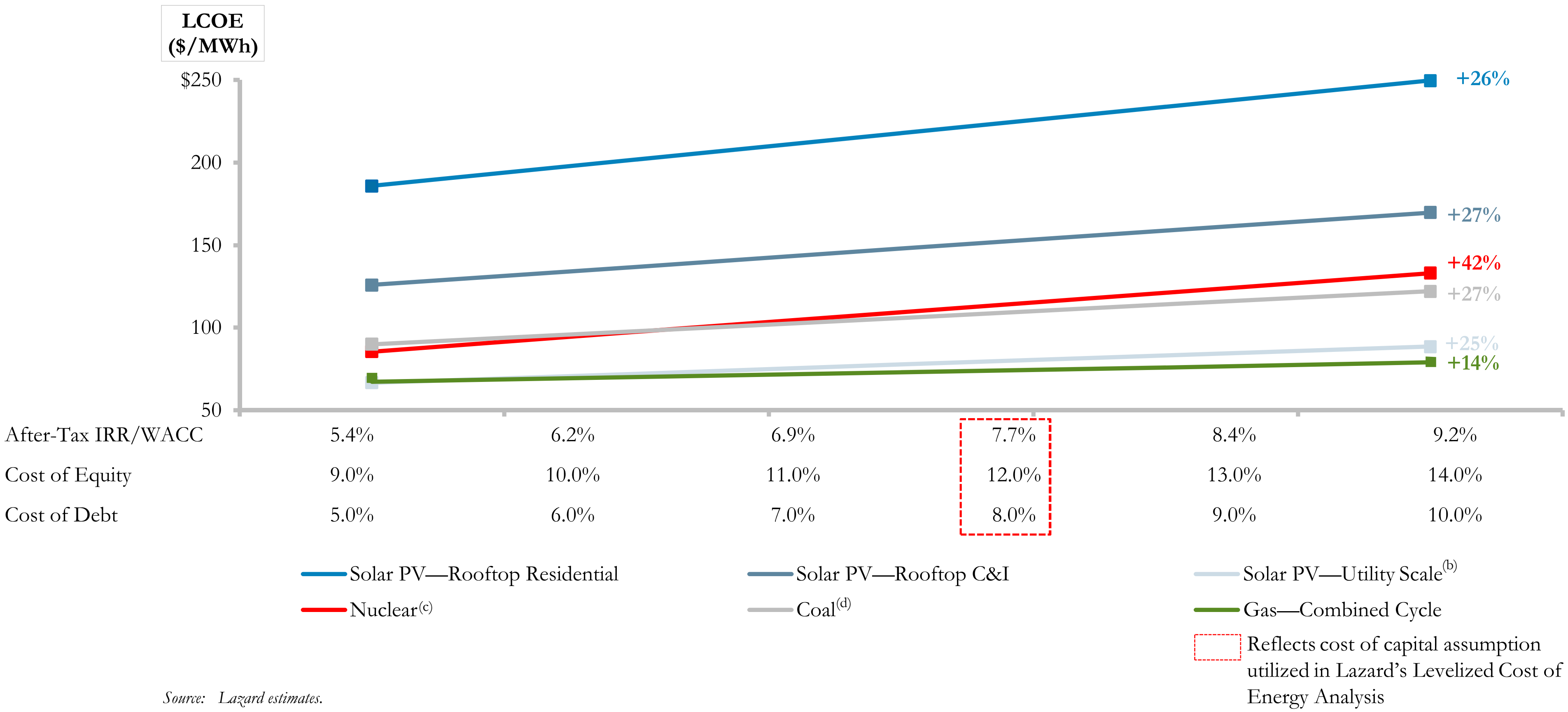


Source: Lazard estimates.

(a) High end represents single-axis tracking. Low end represents fixed-tilt installation.
(b) Diamond represents estimated capital costs in 2017, assuming $1.25 per watt for a single-axis tracking system.
(c) Low end represents concentrating solar tower with 10-hour storage capability. High end represents concentrating solar tower with 18-hour storage capability.
(d) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.
(e) Indicative range based on current stationary storage technologies.
(f) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(g) Represents estimate of current U.S. new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.
(h) Represents estimate of current U.S. new nuclear construction.
(i) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(j) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy—Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies resulting from the potential for intermittently disrupted capital markets (and the relatively immature state of some aspects of financing Alternative Energy technologies) is the impact of the availability and cost of capital[(a)] on their LCOEs; availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them



Source: Lazard estimates.

(a) Cost of capital associated with the particular Alternative Energy generation technology (not the cost of capital of the investor/developer).

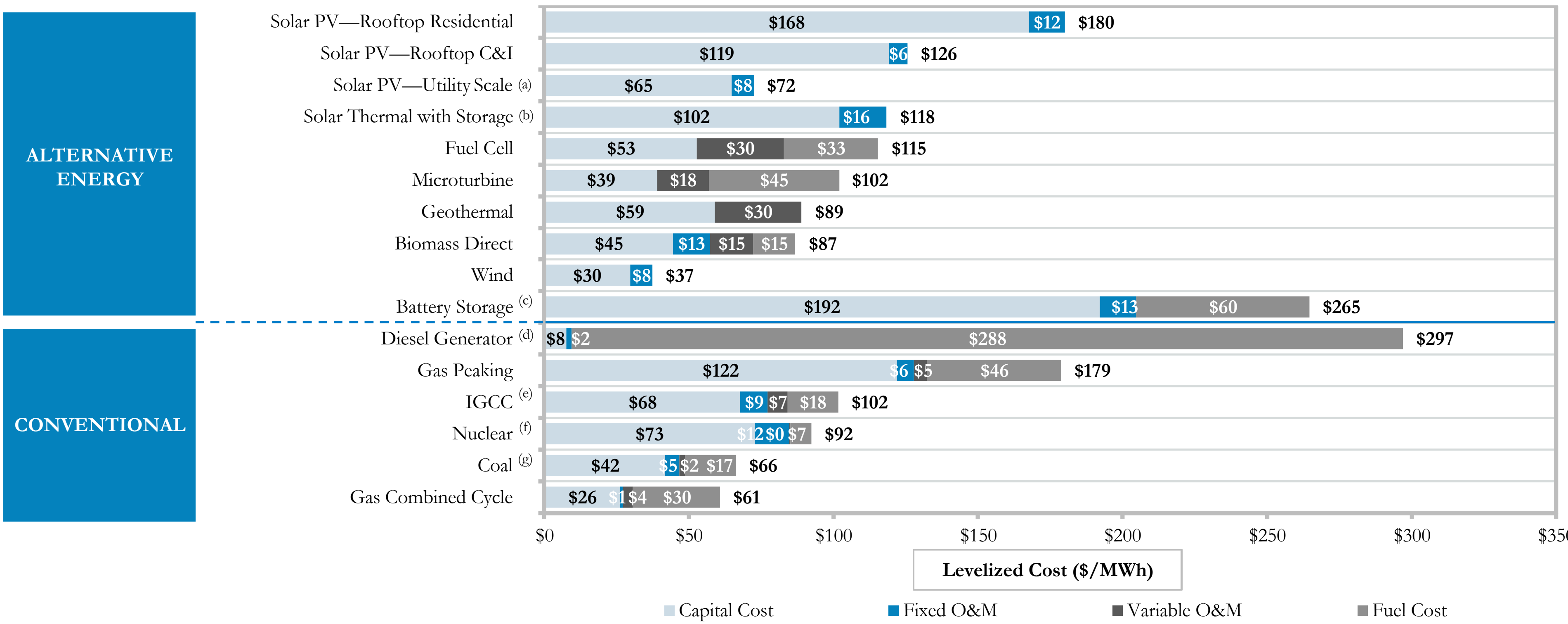
(b) Assumes a fixed-tilt Solar PV utility-scale system with capital costs of $1.50 per watt.

(c) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(d) Based on advanced supercritical pulverized coal.

Levelized Cost of Energy Components—Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)

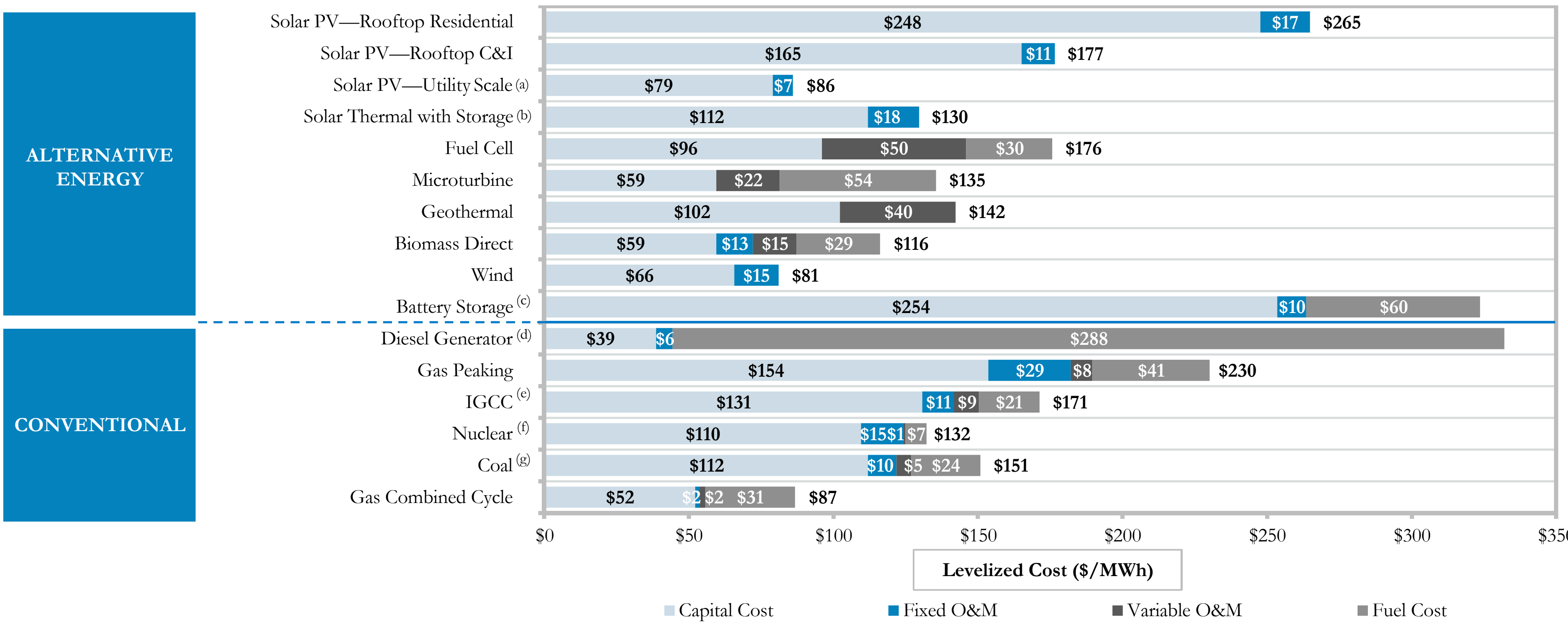


Source: Lazard estimates.

(a) Low end represents single-axis tracking.
(b) Low end represents concentrating solar tower with 18-hour storage capability.
(c) Low end represents lead acid battery.
(d) Low end represents continuous operation.
(e) Does not incorporate carbon capture and compression.
(f) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(g) Based on advanced supercritical pulverized coal. Does not incorporate carbon capture and compression.

Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)



Source: Lazard estimates.

(a) High end represents fixed-tilt installation.
(b) High end represents concentrating solar tower with 10-hour storage capability.
(c) High end represents NaS technology.
(d) High end represents intermittent operation.
(e) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(f) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(g) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is becoming increasingly competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., central station vs. customer-located) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- **This analysis does not take into account potential social and environmental externalities or reliability-related considerations**

					LOCATION			DISPATCH			
		LEVELIZED COST OF ENERGY	CARBON NEUTRAL/ REC POTENTIAL	STATE OF TECHNOLOGY	CUSTOMER LOCATED	CENTRAL STATION	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	SOLAR PV	$72 – 265[(a)]	✓	Commercial	✓	✓	Universal[(b)]	✓	✓		
	SOLAR THERMAL	$118 – 130[(a)]	✓	Commercial		✓	Southwest	✓	✓	✓	
	FUEL CELL	$115 – 176	?	Emerging/ Commercial	✓		Universal				✓
	MICROTURBINE	$102 – 135	?	Emerging/ Commercial	✓		Universal				✓
	GEOTHERMAL	$89 – 142	✓	Mature		✓	Varies				✓
	BIOMASS DIRECT	$87 – 116	✓	Mature		✓	Universal			✓	✓
	ONSHORE WIND	$37 – 81	✓	Mature		✓	Varies	✓			
	BATTERY STORAGE	$265 – 324	✓	Emerging	✓	✓	Varies		✓	✓	
CONVENTIONAL	DIESEL GENERATOR	$297 – 332	×	Mature	✓		Universal	✓	✓	✓	✓
	GAS PEAKING	$179 – 230	×	Mature	✓	✓	Universal		✓	✓	
	IGCC	$102 – 171	×[(c)]	Emerging[(d)]		✓	Co-located or rural				✓
	NUCLEAR	$92 – 132	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$66 – 151	×[(c)]	Mature[(d)]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$61 – 87	×	Mature	✓	✓	Universal			✓	✓

Source: *Lazard estimates.*
(a) LCOE study capacity factor assumes Southwest location.
(b) Qualification for RPS requirements varies by location.
(c) Could be considered carbon neutral technology, assuming carbon capture and compression.
(d) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy—Key Assumptions

		Solar PV					
	Units	Rooftop—Residential	Rooftop—C&I	Utility Scale—Crystalline[c]	Utility Scale—Thin Film[c]	Solar Thermal Tower with Storage[d]	Fuel Cell
Net Facility Output	MW	0.005	1	10	10	75 – 110	2.4
EPC Cost	$/kW	$3,500 – $4,500	$2,500 – $3,000	$1,750 – $1,500	$1,750 – $1,500	$8,750 – $6,250	$3,000 – $7,500
Capital Cost During Construction	$/kW	included	included	included	included	$1,050 – $750	included
Other Owner's Costs	$/kW	included	included	included	included	included	$800 – included
Total Capital Cost[a]	$/kW	$3,500 – $4,500	$2,500 – $3,000	$1,750 – $1,500	$1,750 – $1,500	$9,800 – $7,000	$3,800 – $7,500
Fixed O&M	$/kW-yr	$25.00 – $30.00	$13.00 – $20.00	$20.00 – $13.00	$20.00 – $13.00	$115.00 – $80.00	––
Variable O&M	$/MWh	––	––	––	––	––	$30 – $50
Heat Rate	Btu/kWh	––	––	––	––	––	7,260 – 6,600
Capacity Factor	%	23% – 20%	23% – 20%	30% – 21%	30% – 21%	80% – 52%	95%
Fuel Price	$/MMBtu	––	––	––	––	––	$4.50
Construction Time	Months	3	3	12	12	30	3
Facility Life	Years	20	20	20	20	40	20
CO_2 Emissions	lb/MMBtu	––	––	––	––	––	0 – 117
Investment Tax Credit[b]	%	––	––	––	––	––	––
Production Tax Credit[b]	$/MWh	––	––	––	––	––	––
Levelized Cost of Energy[b]	$/MWh	$180 – $265	$126 – $177	$72 – $86	$72 – $86	$118 – $130	$115 – $176

Source: *Lazard estimates.*

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies."

(c) Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(d) Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Microturbine	Geothermal	Biomass Direct	Wind	Off-Shore Wind	Battery Storage[c]
Net Facility Output	MW	1	30	35	100	210	6
EPC Cost	$/kW	$2,300 – $3,800	$4,021 – $6,337	$2,622 – $3,497	$1,100 – $1,400	$2,500 – $4,620	$500 – $750
Capital Cost During Construction	$/kW	included	$579 – $913	$378 – $503	included	included	included
Other Owner's Costs	$/kW	included	included	included	$300 – $400	$600 – $880	included
Total Capital Cost[a]	$/kW	$2,300 – $3,800	$4,600 – $7,250	$3,000 – $4,000	$1,400 – $1,800	$3,100 – $5,500	$500 – $750
Fixed O&M	$/kW-yr	—	—	$95.00	$35.00 – $40.00	$60.00 – $100.00	$27.50 – $22.00
Variable O&M	$/MWh	$18.00 – $22.00	$30.00 – $40.00	$15.00	—	$13.00 – $18.00	—
Heat Rate	Btu/kWh	10,000 – 12,000	—	14,500	—	—	—
Capacity Factor	%	95%	90% – 80%	85%	52% – 30%	43% – 37%	25% – 25%
Fuel Price	$/MMBtu	$4.50	—	$1.00 – $2.00	—	—	$60[c]
Construction Time	Months	3	36	36	12	12	3
Facility Life	Years	20	20	20	20	20	20
CO_2 Emissions	lb/MMBtu	—	—	—	—	—	—
Investment Tax Credit[b]	%	—	—	—	—	—	—
Production Tax Credit[b]	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$102 – $135	$89 – $142	$87 – $116	$37 – $81	$110 – $214	$265 – $324

Source: Lazard estimates.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies."

(c) Assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Diesel Generator[c]	Gas Peaking	IGCC[d]	Nuclear[e]	Coal[f]	Gas Combined Cycle
Net Facility Output	MW	2	216 – 103	580	1,100	600	550
EPC Cost	$/kW	$500 – $800	$580 – $700	$3,257 – $6,390	$3,750 – $5,250	$2,027 – $6,067	$743 – $1,004
Capital Cost During Construction	$/kW	included	included	$743 – $1,610	$1,035 – $1,449	$487 – $1,602	$107 – $145
Other Owner's Costs	$/kW	included	$220 – $300	included	$600 – $1,500	$486 – $731	$156 – $170
Total Capital Cost[a]	$/kW	$500 – $800	$800 – $1,000	$4,000 – $8,000	$5,385 – $8,199	$3,000 – $8,400	$1,006 – $1,318
Fixed O&M	$/kW-yr	$15.00	$5.00 – $25.00	$62.25 – $73.00	$95.00 – $115.00	$40.00 – $80.00	$6.20 – $5.50
Variable O&M	$/MWh	—	$4.70 – $7.50	$7.00 – $8.50	$0.25 – $0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	10,000	10,300 – 9,000	8,800 – 10,520	10,450	8,750 – 12,000	6,700 – 6,900
Capacity Factor	%	95% – 30%	10%	75%	90%	93%	70% – 40%
Fuel Price	$/MMBtu	$28.76	$4.50	$1.99	$0.70	$1.99	$4.50
Construction Time	Months	3	25	57 – 63	69	60 – 66	36
Facility Life	Years	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 – 117	117	169	—	211	117
Investment Tax Credit[b]	%	—	—	—	—	—	—
Production Tax Credit[b]	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$297 – $332	$179 – $230	$102 – $171	$92 – $132	$66 – $151	$61 – $87

Source: *Lazard estimates.*

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies."

(c) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

(d) High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(f) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase, and government subsidies in certain regions.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, and economic life) were identical for all technologies, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and U.S. federal tax incentives on the levelized cost of energy. These inputs were developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This study (as well as previous versions) has benefitted from additional input from a wide variety of industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.).