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MISO

Cost of New Entry PY 2020/21

Resource Adequacy Subcommittee

11 September 2019

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Purpose & Key Takeaways

Purpose:

Present summary of updated efforts on locational Cost of New Entry ("CONE") values

Key Takeaways:

- FERC filing will be made this week for estimates of MISO's CONE values for 2020/2021 Planning Year
- MISO's estimates are up on last year's estimates systematically across all LRZs.

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Sections

- Introduction
- Inputs
- Methodology
- Results

Introduction

- Cost of New Entry is an industry-wide term, used to indicate the current, annualised, capital cost of constructing a power plant.
  - The plant is assumed to be used infrequently.
  - The calculations made by various entities use differing assumptions and methods.
- CONE is used by MISO primarily as the maximum offer and maximum clearing price, converted to a daily value, in the Planning Resource Auctions.
- Net CONE is a related concept, wherein expected inframarginal rents from energy & ancillary services are subtracted from the CONE value.
  - Not currently in use at MISO

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Tariff Provisions

Section 69A.8

MISO and the Independent Market Monitor ("IMM") determine the CONE value for each LRZ, as follows:

- Consider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ.

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Inputs

- Primary Inputs
  - Economic
    - Implicit price deflator
    - O&M escalation factor (2.37%)
  - Financial
    - 55/45 debt/equity ratio
    - 20-year project/finance life
    - 6.20% cost of debt
    - 13.4% after tax return on equity
    - 26.7% effective tax rate
  - Capital Costs, by Local Resource Zone (EIA)
    - See filing, Attachment A
  - Operation & Maintenance Costs (EIA)

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Methodology

- Capital costs annualised using net present value (NPV) method
- O&M costs escalated, then annualised using NPV
- Insurance & property taxes are add-on costs
  - 1.5% of the capital costs
- Results checked and normalised against IMM calculations

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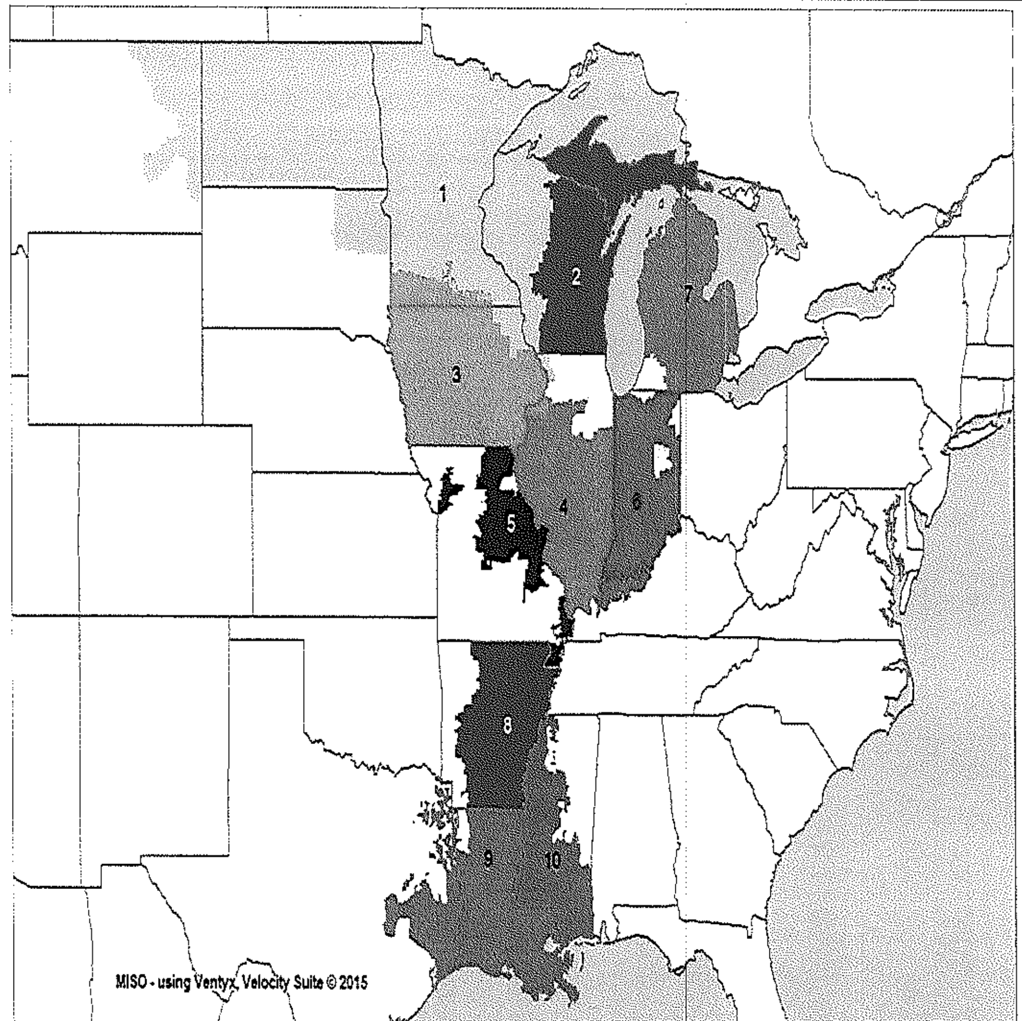
Results

ZONE	PY 2020/21 CONE $\$*(MW*yr)^{-1}$	PY 2019/20 CONE $\$*(MW*yr)^{-1}$
LRZ 1	$ 93,470	$ 88,460
LRZ 2	$ 91,860	$ 87,170
LRZ 3	$ 91,330	$ 87,420
LRZ 4	$ 92,960	$ 88,390
LRZ 5	$ 95,190	$ 89,960
LRZ 6	$ 93,030	$ 87,780
LRZ 7	$ 94,000	$ 88,830
LRZ 8	$ 89,660	$ 84,780
LRZ 9	$ 86,350	$ 81,640
LRZ10	$ 89,410	$ 84,370



Contact Information

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DECEMBER 2016

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 10.0

LAZARD

Introduction

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

- Comparative "levelized cost of energy" analysis 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 for various generation technologies
- Illustration of how the cost of various generation technologies compares against illustrative generation rates in a subset of the largest metropolitan areas of the U.S.
- 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 U.S., based on illustrative regional resources
- Illustration of the declines in the levelized cost of energy for various generation technologies over the past several years
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Illustration of the impact of cost of capital on the levelized cost of energy for selected 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 or other integration-related costs; significant permitting or other development costs, unless otherwise noted; 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 – 10.0 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.

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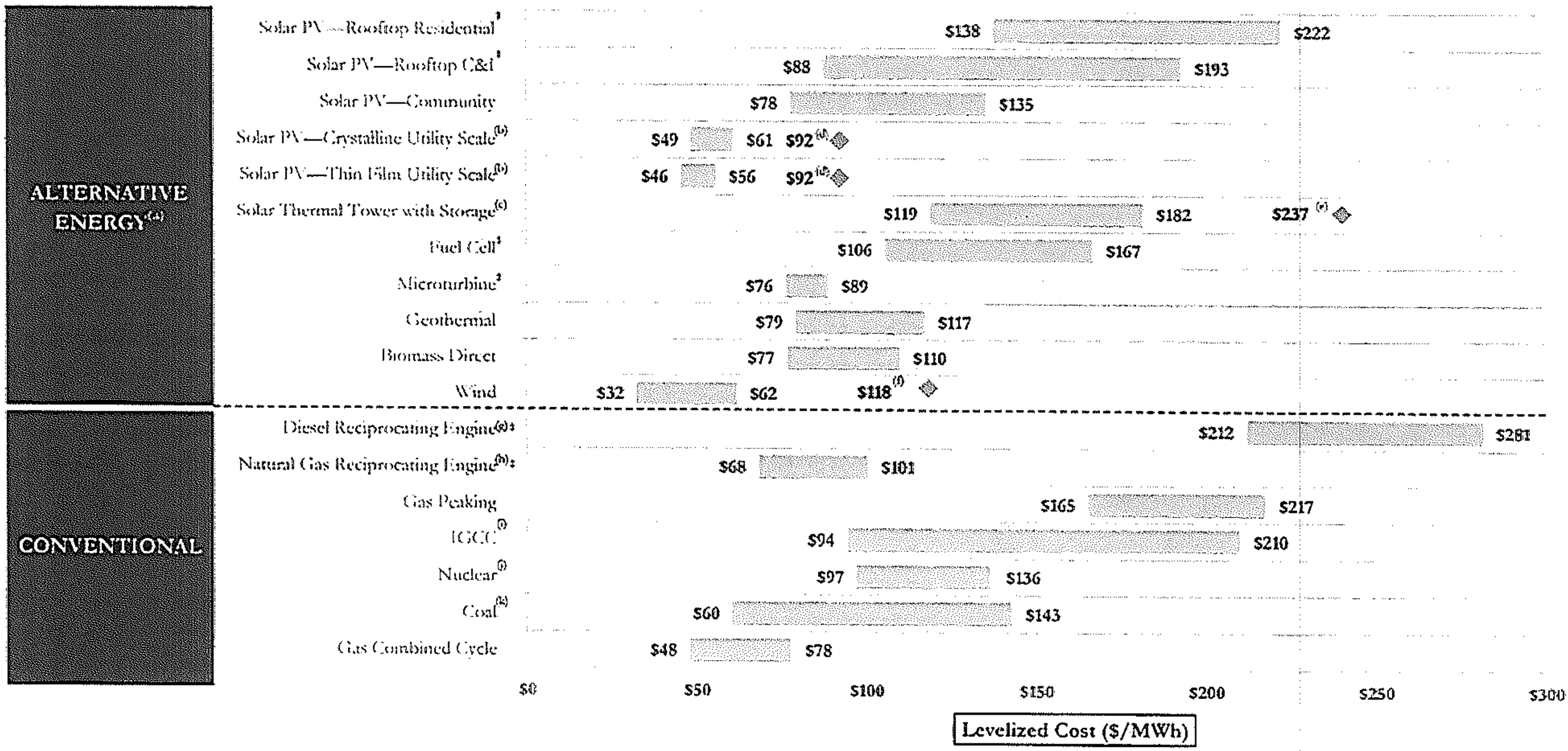
Unsubsidized Levelized Cost of Energy Comparison

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.), reliability or intermittency-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy 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. Reflects global, illustrative costs of capital, which may be significantly higher than OECD country costs of capital. See page 15 for additional details on cost of capital. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d). See pages 18–20 for fuel costs for each technology. See following page for footnotes.

‡ Denotes distributed generation technology.

Unsubsidized Levelized Cost of Energy Comparison (cont'd)

(a) Analysis excludes integration (e.g., grid and conventional generation investment to overcome system intermittency) costs for intermittent technologies.

(b) Low end represents single-axis tracking system. High end represents fixed-tilt design. Assumes 30 MW system in a high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients within technologies, balance-of-system costs or other potential factors which may differ across select solar technologies or more specific geographies.

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

(d) Illustrative "PV Plus Storage" unit. PV and battery system (and related mono-directional inverter, power control electronics, etc.) sized to compare with solar thermal with 10 hour storage on capacity factor basis (52%). Assumes storage nameplate "usable energy" capacity of ~400 MWh_{dc}, storage power rating of 110 MW_{ac} and ~200 MW_{ac} PV system. Implied output degradation of ~0.40%/year (assumes PV degradation of 0.5%/year and battery energy degradation of 1.5%/year, which includes calendar and cycling degradation). Battery round trip DC efficiency of 90% (including auxiliary losses). Storage opex of ~$10/kWh-year and PV O&M expense of ~$9.2/kW DC-year, with 20% discount applied to total opex as a result of synergies (e.g., fewer truck rolls, single team, etc.). Total capital costs of ~$3,900/kW include PV plus battery energy storage system and selected other development costs. Assumes 20 year useful life, although in practice the unit may perform longer. Illustrative system located in U.S. Southwest.

(e) Diamond represents an illustrative solar thermal facility without storage capability.

(f) Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $2.75 – $4.50 per watt.

(g) Represents distributed diesel generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 10% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 25,000 operating hours.

(h) Represents distributed natural gas generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 30% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 60,000 operating hours.

(i) Does not include cost of transportation and storage.

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

(k) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

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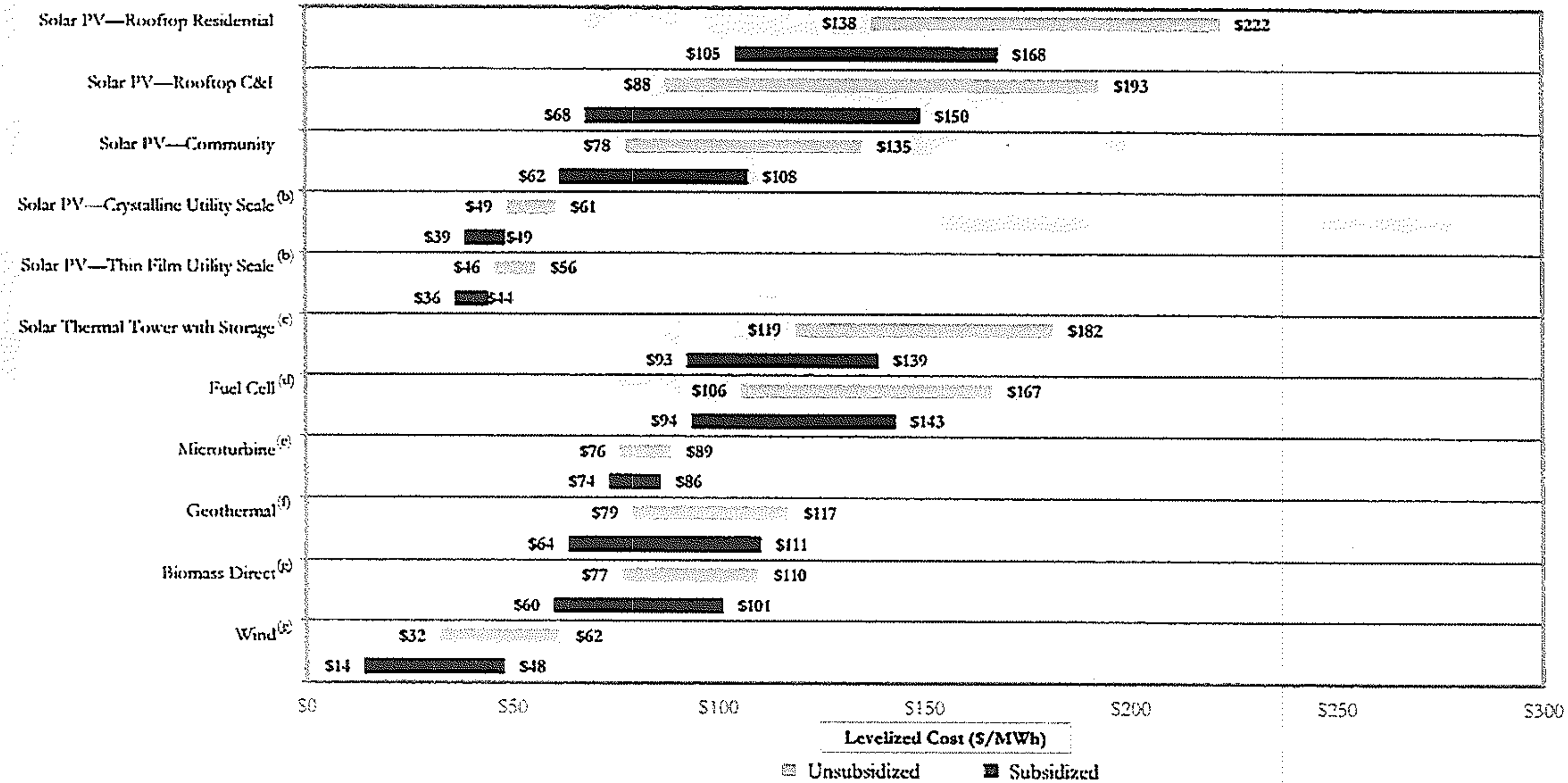
Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies[(a)]

Given the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") in December 2015 and resulting subsidy visibility, 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)



Source: Lazard estimates.

(a) Unless otherwise noted, the subsidized analysis assumes projects placed into service in time to qualify for full PTC/ITC. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 10.0% cost and 20% common equity at 12.0% cost, unless otherwise noted.

(b) Low end represents a single-axis tracking system. High end represents a fixed-tilt design. Assumes 30 MW installation in high insolation jurisdiction (e.g., Southwest U.S.).

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

(d) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

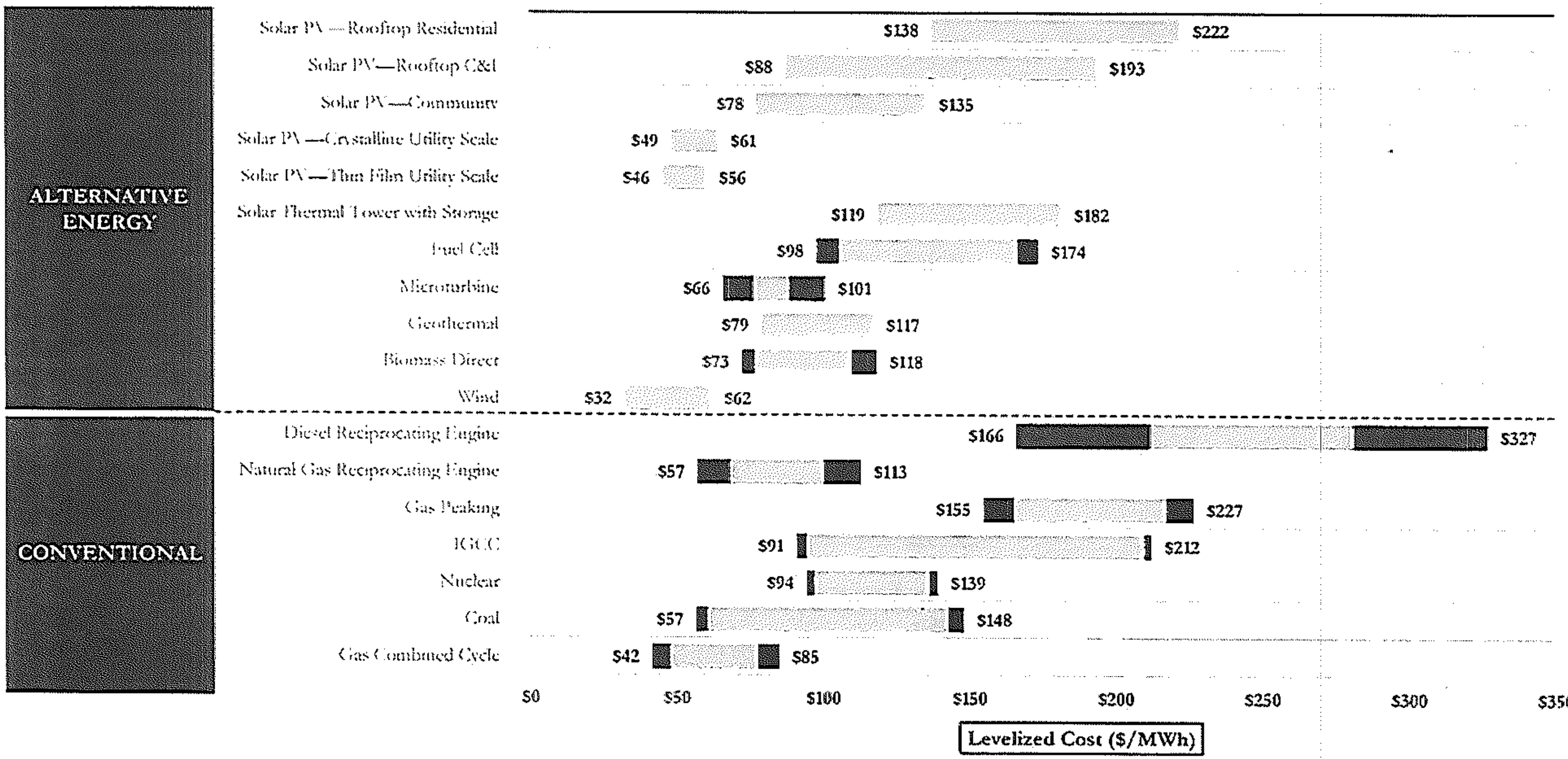
(e) Reflects 10% ITC only. Reflects no PTC. Capital structure adjusted for lower ITC; assumes 50% debt at 8.0% interest rate, 30% tax equity at 10.0% cost and 20% common equity at 12.0% cost.

(f) Reflects no ITC. Reflects $23/MWh PTC, escalated at ~1.5% annually for a term of 10 years.

(g) Reflects no ITC. Reflects $23/MWh PTC, escalated at ~1.5% annually for a term of 10 years. Due to high capacity factor and, relatedly, high PTC investor appetite, assumes 15% debt at 8.0% interest rate, 70% tax equity at 10.0% cost and 15% 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 the Clean Power Plan and related 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 or grid-related considerations**

	Units	CONVENTIONAL GENERATION			ALTERNATIVE ENERGY RESOURCES			
		Coal[b]	Gas Combined Cycle	Nuclear	Wind	Solar PV Rooftop Residential	Solar PV Utility Scale[c]	Solar Thermal with Storage[d]
Capital Investment/KW of Capacity[a]	$/kW	$3,000	$1,006	$5,385	$1,250	$2,000	$1,450	$10,296
Total Capital Investment	**$mm**	**$1,800**	**$704**	**$3,339**	**$1,263**	**$6,380**	**$2,697**	**$6,795**
Facility Output	MW	600	700	620	1010	3190	1860	660
Capacity Factor	%	93%	80%	90%	55%	18%	30%	85%
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	$60	$48	$97	$32	$138	$49	$119
Total Cost of Energy Produced	**$mm/yr**	**$\boxed{\$296}$ (2)**	**$234**	**$474**	**$158**	**$673**	**$\boxed{\$237}$ (1)**	**$582**
CO_2 Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51	4.51	$\boxed{4.51}$ (3)	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($62)	$179	($138)	$377	$\boxed{(\$58)}$ (4)	$286
vs. Gas		—	—	$241	($76)	$439	$4	$348
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		—	($31)	$40	($31)	$84	$\boxed{(\$13)}$ (5)	$63
vs. Gas		—	—	$96	($30)	$176	$1	$139

Source: Lazard estimates.

Note: Unsubsidized figures. Assumes 2016 dollars, 20 – 40 year economic life, 40% tax rate and five – 40 year tax life. Assumes 2.25% 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. LCOE figures calculated on a 20-year basis.

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

(b) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

(c) Represents crystalline utility-scale solar with single-axis tracking.

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

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

Illustrative Implied Carbon Abatement Cost Calculation:

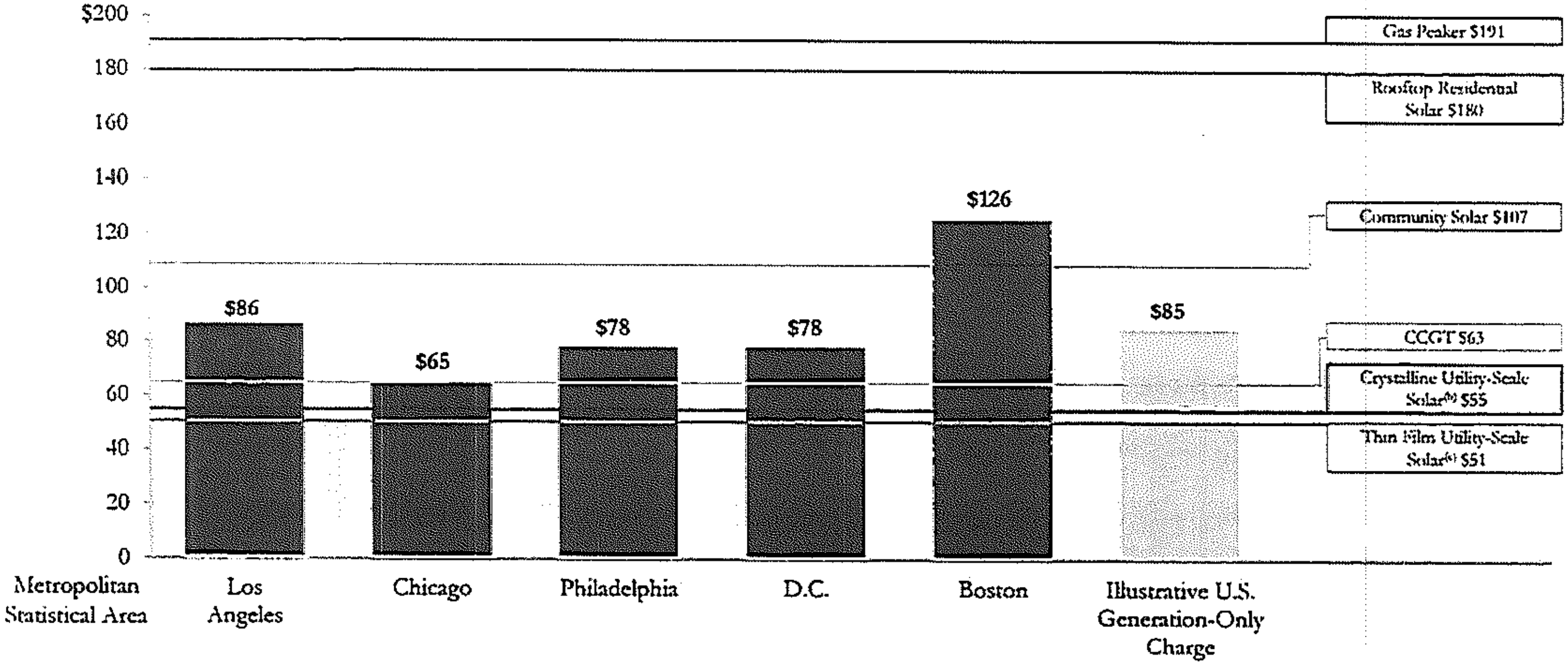
(4) Difference in Total Energy Cost vs. Coal = (1) – (2)
= $237 mm/yr (solar) – $296 mm/yr (coal) = ($58) mm/yr

(5) Implied Abatement Cost vs. Coal = (4) ÷ (3)
= ($58) mm/yr ÷ 4.51 mm Tons/yr = ($13)/Ton

Generation Rates for Selected Large 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 key, high population 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**



Source: EEI, Lazard estimates.

Note: Actual delivered generation prices may be higher, reflecting historical composition of resource portfolio. All technologies represent an average of the high and low levelized cost of energy values unless otherwise noted. Represents average retail rate for generation-only utility charges per EEI for 12 months ended December 31, 2015.

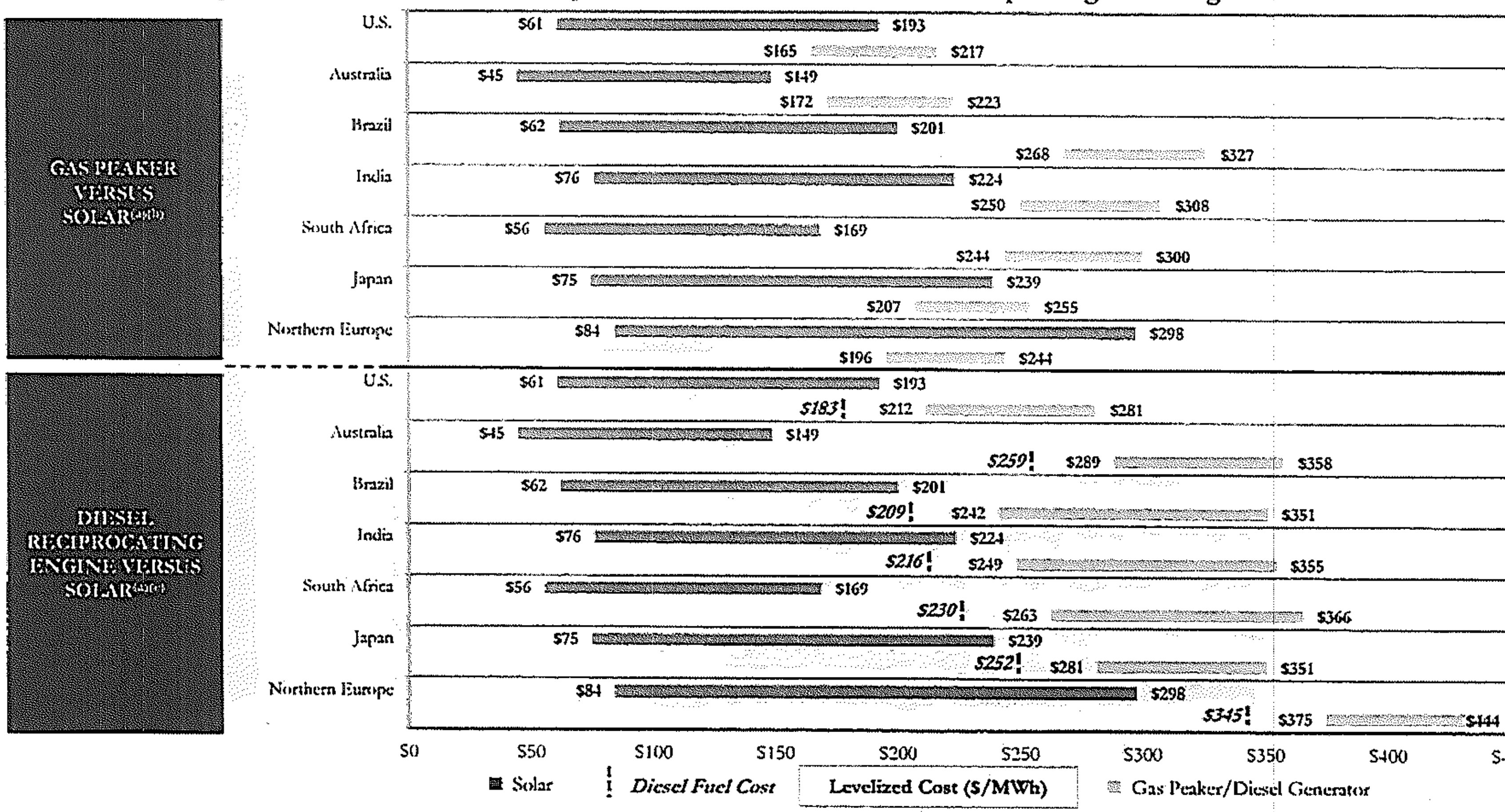
(a) Includes only those cities among top ten in population (per U.S. census) for which generation-only average $/kWh figures are available.

(b) Represents crystalline utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.

(c) Represents thin film utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.

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 and Lazard estimates.

(a) Low end assumes crystalline utility-scale solar with a fixed-tilt design. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 26% – 30% for Australia, 26% – 30% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% 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 $4.00 for Australia, $8.00 for Brazil, $7.00 for India, $7.00 for South Africa, $7.00 for Japan and $6.00 for Northern Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10%.

(c) Diesel assumes high end capacity factor of 10% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization, O&M cost of $30 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 $3.60 for Australia, $2.90 for Brazil, $3.00 for India, $3.20 for South Africa, $3.50 for Japan and $4.80 for Northern Europe (all in U.S.$ per gallon).

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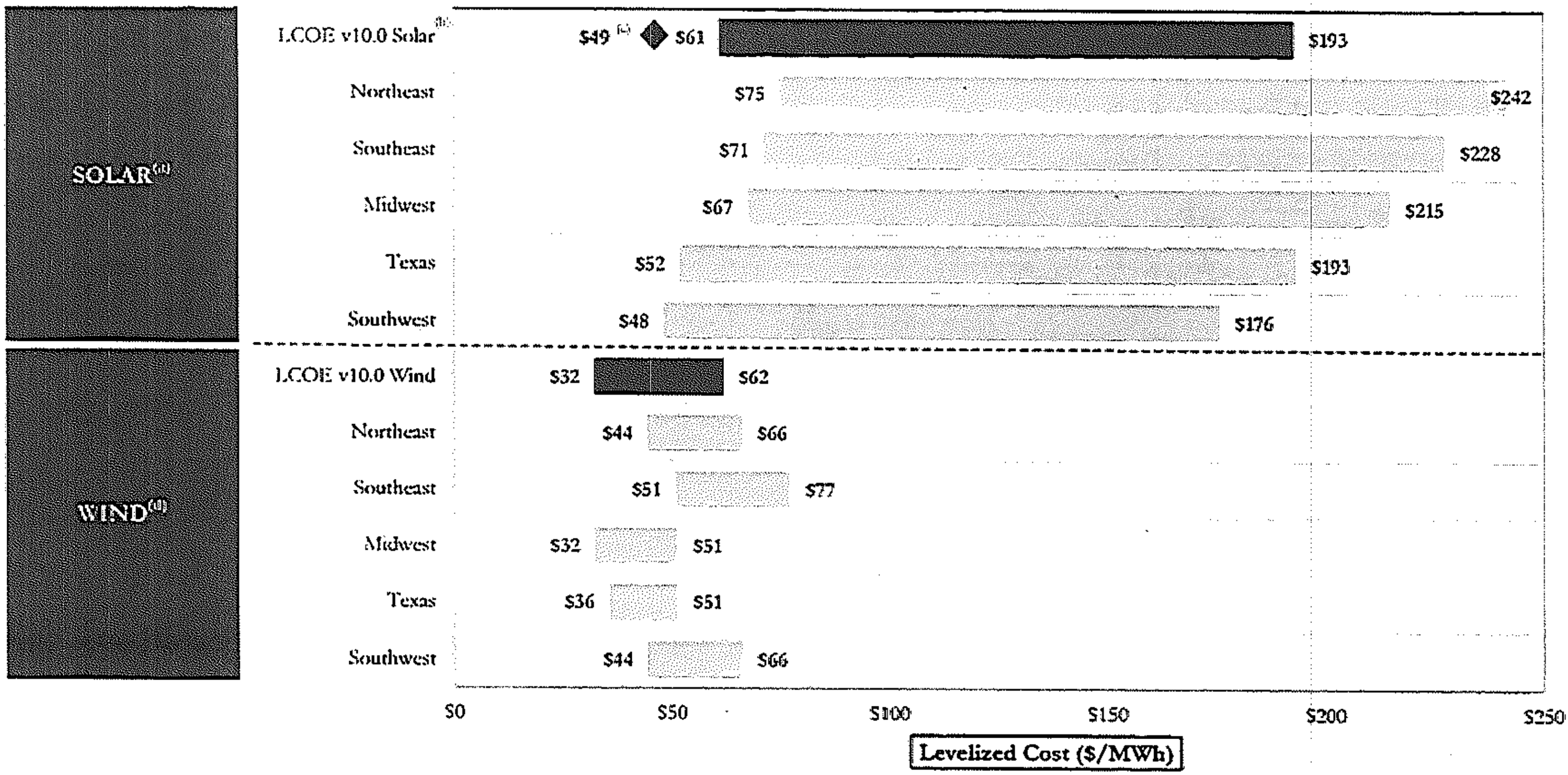
Wind and Solar Resource—U.S. Regional Sensitivity (Unsubsidized)

The availability of wind and solar resource has a meaningful impact on the levelized cost of energy for various regions of the U.S. 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, 20% – 26% for Texas and 22% – 28% for the Southwest. Assumes wind capacity factors of 35% – 40% for the Northeast, 30% – 35% for the Southeast, 45% – 55% for the Midwest, 45% – 50% for Texas and 35% – 40% for the Southwest.

(a) Low end assumes a crystalline utility-scale solar fixed-tilt design, as tracking technologies may not be available in all geographies. High end assumes a rooftop C&I solar system.

(b) Low end assumes a crystalline utility-scale solar fixed-tilt design with a capacity factor of 21%.

(c) Diamond represents a crystalline utility-scale solar single-axis tracking system with a capacity factor of 30%.

(d) Assumes an onshore wind generation plant with capital costs of $1.25 – $1.70 per watt.

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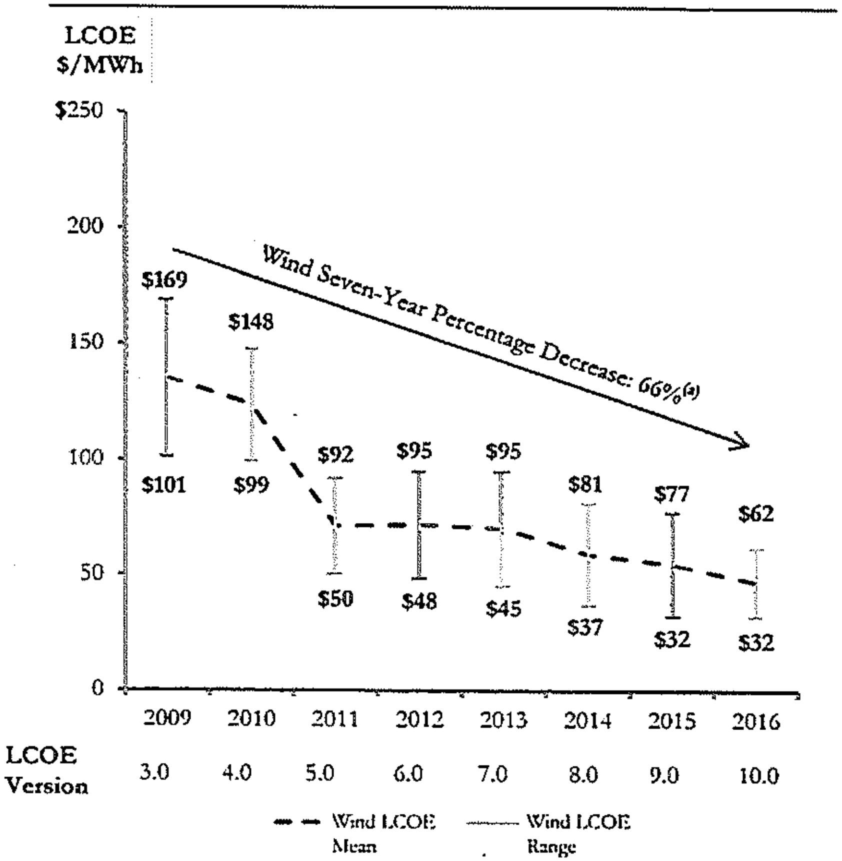
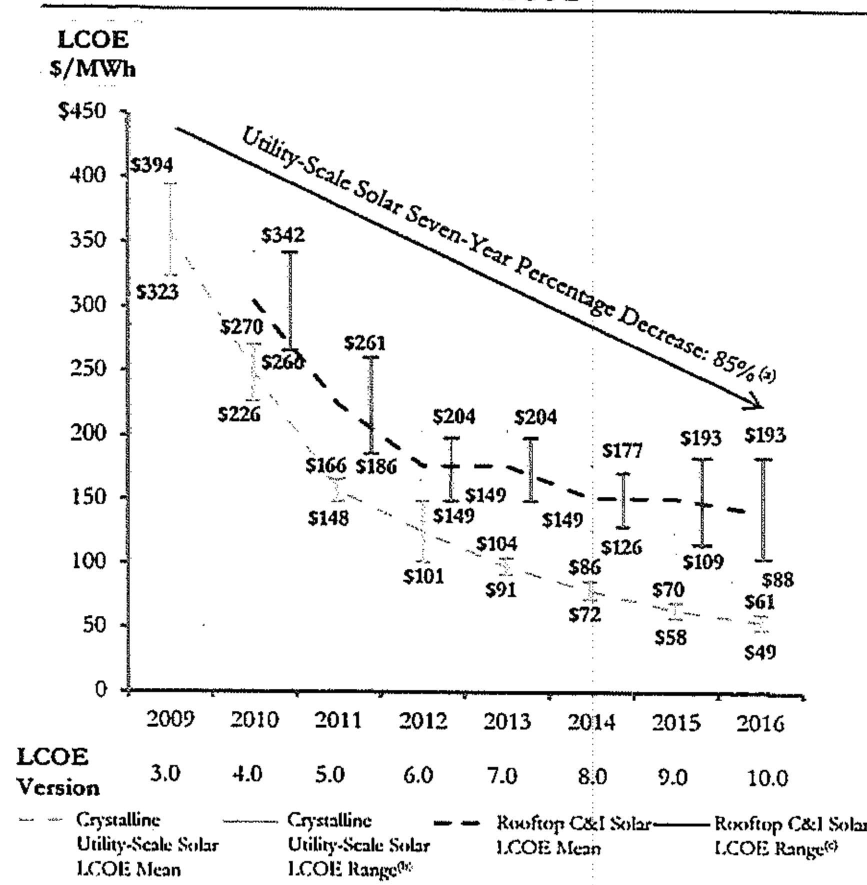
Unsubsidized Levelized Cost of Energy—Wind/Solar PV (Historical)

Over the last seven 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





Source: *Lazard estimates.*

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

(b) Low end represents crystalline utility-scale solar with single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.), while high end represents crystalline utility-scale solar with fixed-tilt design.

(c) Lazard's LCOE initiated reporting of rooftop C&I solar in 2010.

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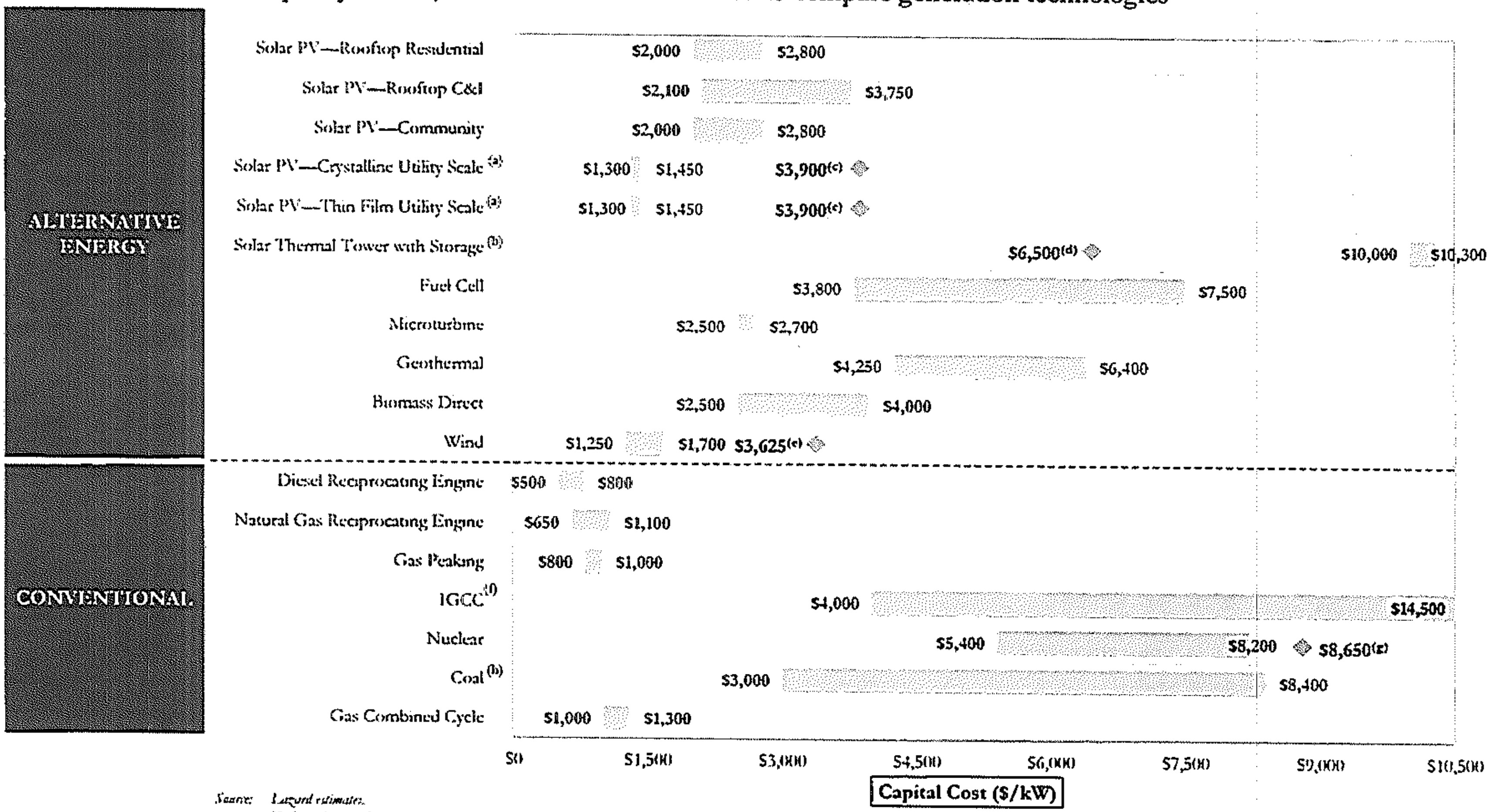
Capital Cost Comparison

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 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 capital cost represents the capital cost associated with the low end LCOE of utility-scale solar. Low end capital cost represents the capital cost associated with the high end LCOE of utility-scale solar.
(b) Low end represents concentrating solar tower with 10-hour storage capability. High end represents concentrating solar tower with 18-hour storage capability.
(c) Diamond represents PV plus storage.
(d) Diamond represents solar thermal tower capital costs without storage.
(e) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $2.75 – $4.50 per watt.
(f) High end represents Kemper and it incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(g) Represents estimate of current U.S. new nuclear construction.
(h) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

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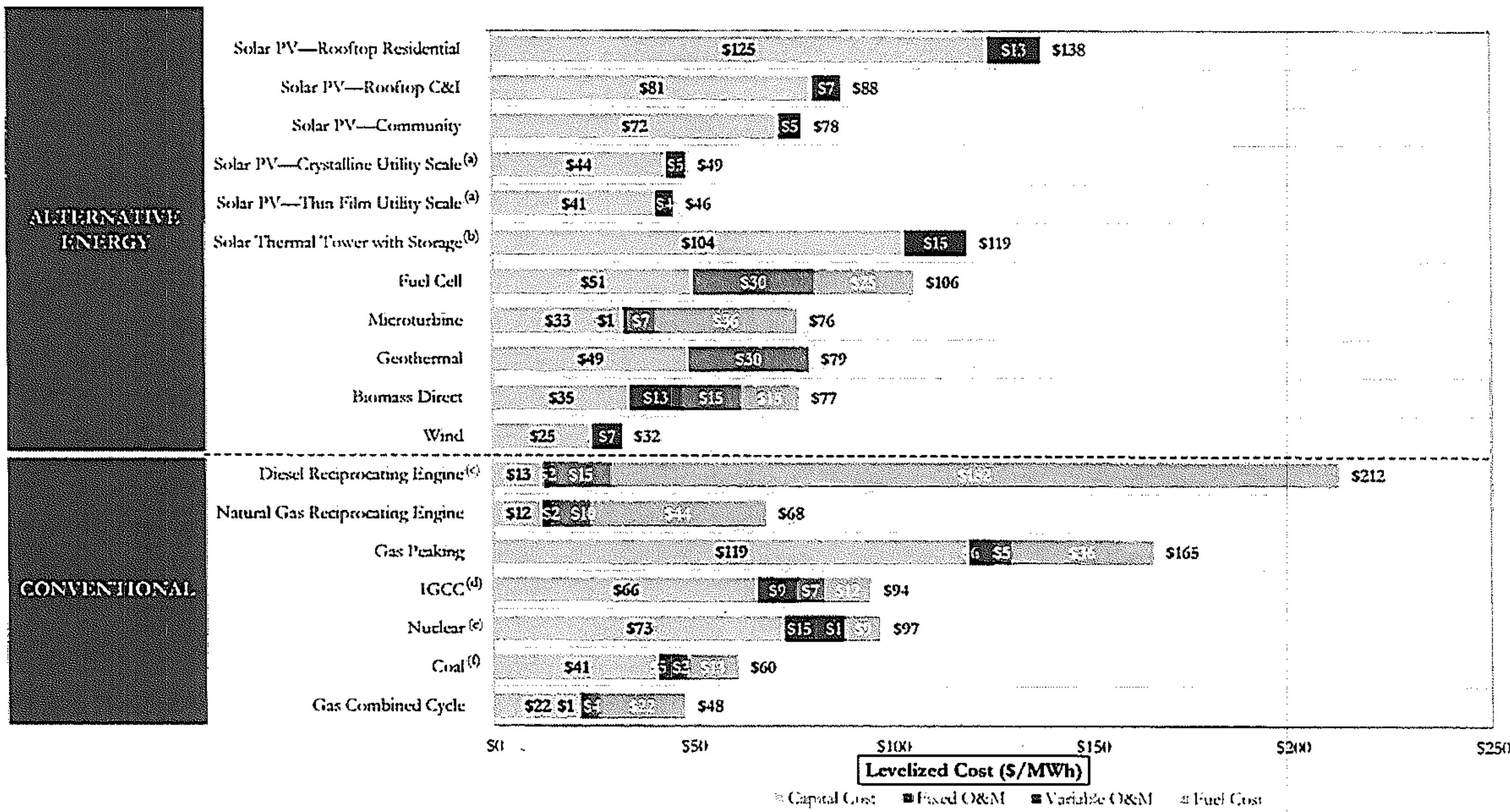
Levelized Cost of Energy Components—Low End

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)

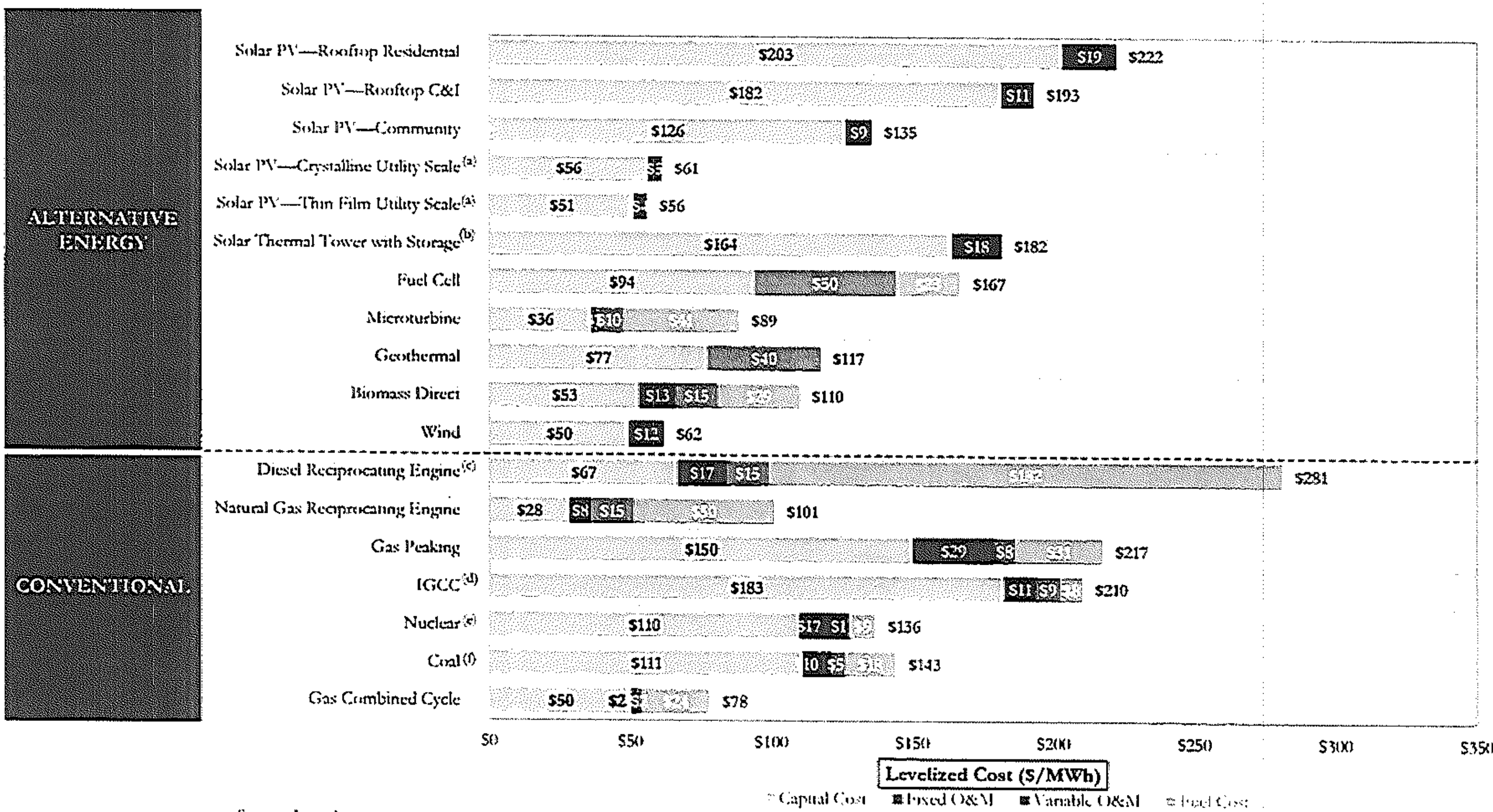


Source: *Lazard estimates.*

(a) Represents the low end of a utility-scale solar single-axis tracking system.
(b) Represents concentrating solar tower with 18-hour storage capability.
(c) Represents continuous operation.
(d) Does not incorporate carbon capture and compression.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(f) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail 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) Represents the high end of utility-scale solar fixed-tilt design.
(b) Represents concentrating solar tower with 10-hour storage capability.
(c) Represents intermittent operation.
(d) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(f) Based on of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

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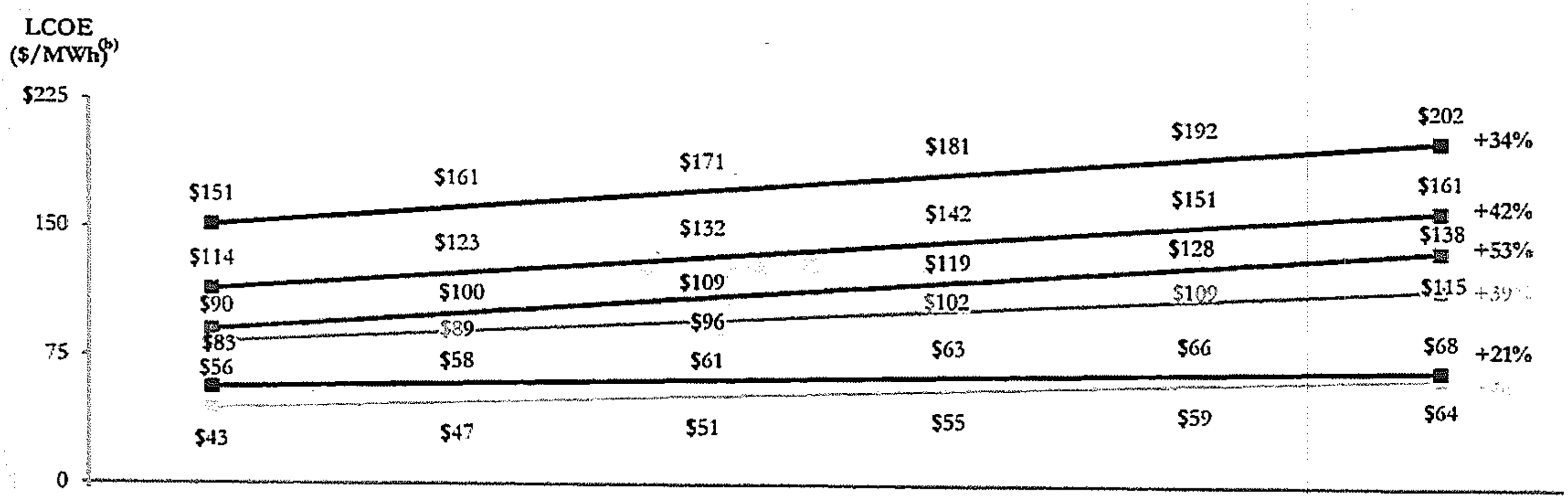
Levelized Cost of Energy—Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies is the impact of the availability and cost of capital[a] on LCOEs (as a result of capital markets dislocation, technological maturity, etc.); 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



After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Solar PV—Rooftop Residential
Solar PV—Rooftop C&I
Solar PV—Utility Scale
Nuclear [c]
Coal [d]
Gas—Combined Cycle

Reflects cost of capital assumption utilized in Lazard's Levelized Cost of Energy analysis

Reflects potentially more prevalent North American cost of capital—see next page for additional details

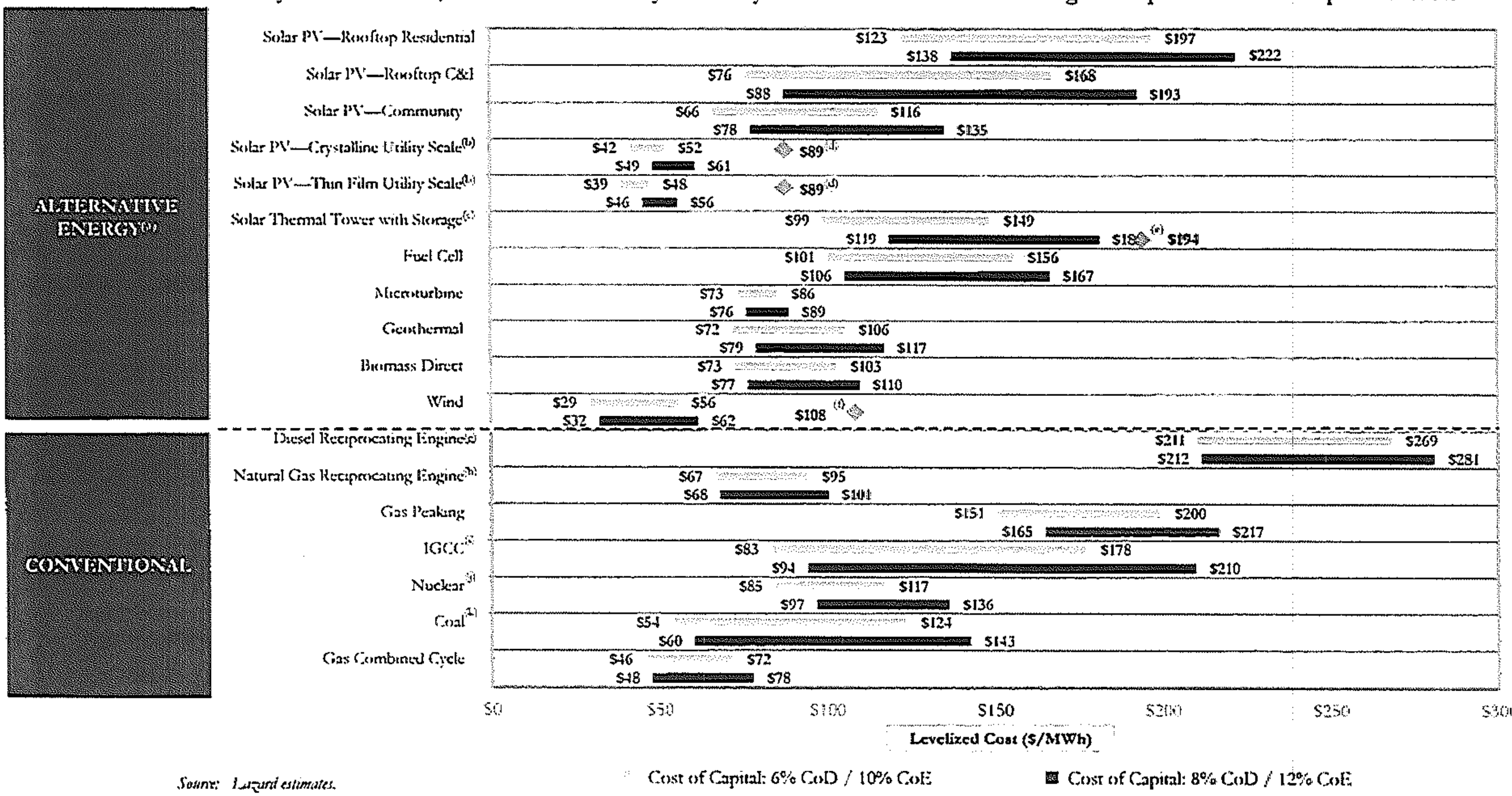
Source: *Lazard estimates.*

(a) Cost of capital as used herein indicates the cost of capital for the asset/plant vs. the cost of capital of a particular investor/owner.
(b) Reflects average of high and low LCOE for given cost of capital assumption.
(c) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(d) Based on average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

Ex. AA-D-20

Unsubsidized Levelized Cost of Energy—Cost of Capital Comparison

While Lazard's analysis primarily reflects an illustrative global cost of capital (i.e., 8% cost of debt and 12% cost of equity), such assumptions may be somewhat elevated vs. OECD/U.S. figures currently prevailing in the market for utility-scale renewables assets/investment—in general, Lazard aims to update its major levelized assumptions (e.g., cost of capital, capital structure, etc.) only in extraordinary circumstances, so that results track year-over-year cost declines and technological improvements vs. capital markets



Source: *Lazard estimates.*
Note: Reflects equivalent cost and operational assumptions as pages 2 – 3. Analysis assumes 60% debt at 6% interest rate and 40% equity at 10% cost for conventional and Alternative Energy generation technologies. Assumes an average coal price of $1.47 per MMBtu based on Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Assumes a range of $0.65 – $1.33 per MMBtu based on Illinois Based Rail for IGCC. Assumes a natural gas price of $3.45 per MMBtu for Fuel Cell, Microturbine, Gas Peaking and Gas Combined Cycle. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).
‡ Denotes distributed generation technology.

Ex. AA-D-20

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is in some cases competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) 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	DISTRIBUTED	CENTRALIZED	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	SOLAR PV	\$46 – 222(a)	✓	Commercial	✓	✓	Universal(b)	✓	✓		
	SOLAR THERMAL	\$119 – 182	✓	Commercial		✓	Varies	✓	✓	✓	
	FUEL CELL	\$106 – 167	?	Emerging/ Commercial	✓		Universal				✓
	MICROTURBINE	\$76 – 89	?	Emerging/ Commercial	✓		Universal				✓
	GEOTHERMAL	\$79 – 117	✓	Mature		✓	Varies				✓
	BIOMASS DIRECT	\$77 – 110	✓	Mature		✓	Universal			✓	✓
	ONSHORE WIND	\$32 – 62	✓	Mature		✓	Varies	✓			
CONVENTIONAL	DIESEL RECIPROCATING ENGINE	\$212 – 281	✗	Mature	✓		Universal	✓	✓	✓	✓
	NATURAL GAS RECIPROCATING ENGINE	\$68 – 101	✗	Mature	✓		Universal	✓	✓	✓	✓
	GAS PEAKING	\$165 – 217	✗	Mature	✓	✓	Universal		✓	✓	
	IGCC	\$94 – 210	✗(c)	Emerging(d)		✓	Co-located or rural				✓
	NUCLEAR	\$97 – 136	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	\$60 – 143	✗(c)	Mature(d)		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	\$48 – 78	✗	Mature	✓	✓	Universal			✓	✓

Source: Lazard estimates.

(a) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(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.

Ex. AA-D-20

Levelized Cost of Energy—Methodology

Lazard's Levelized Cost of Energy analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see pages 18 – 20 for detailed assumptions by technology)

WIND — HIGH CASE SAMPLE CALCULATIONS

Year[a]	*0*	*1*	*2*	*3*	*4*	*5*
Capacity (MW) – (A)		100	100	100	100	100
Capacity Factor (%) – (B)		38%	38%	38%	38%	38%
Total Generation ('000 MWh) – (A) x (B) = (C)*		329	329	329	329	329
Levelized Energy Cost ($/MWh) – (D)		***$61.75***	***$61.75***	***$61.75***	***$61.75***	***$61.75***
Total Revenues – (C) x (D) = (E)*		**$20.3**	**$20.3**	**$20.3**	**$20.3**	**$20.3**
Total Fuel Cost – (F)		$0.0	$0.0	$0.0	$0.0	$0.0
Total O&M – (G)*		4.0	4.1	4.2	4.3	4.4
Total Operating Costs – (F) + (G) = (H)		$4.0	$4.1	$4.2	$4.3	$4.4
EBITDA – (E) - (H) = (I)		**$16.3**	**$16.2**	**$16.1**	**$16.0**	**$15.9**
Debt Outstanding - Beginning of Period – (J)		$102.0	$100.0	$97.8	$95.4	$92.9
Debt - Interest Expense – (K)		(8.2)	(8.0)	(7.8)	(7.6)	(7.4)
Debt - Principal Payment – (L)		(2.0)	(2.2)	(2.4)	(2.5)	(2.8)
Levelized Debt Service – (K) + (L) = (M)		($10.2)	($10.2)	($10.2)	($10.2)	($10.2)
EBITDA – (I)		$16.3	$16.2	$16.1	$16.0	$15.9
Depreciation (MACRS) – (N)		(34.0)	(54.4)	(32.6)	(19.6)	(19.6)
Interest Expense – (K)		(8.2)	(8.0)	(7.8)	(7.6)	(7.4)
Taxable Income – (I) + (N) + (K) = (O)		**($25.9)**	**($46.2)**	**($24.4)**	**($11.2)**	**($11.1)**
Tax Benefit (Liability) – (O) x (tax rate) = (P)[b]		**$10.4**	**$18.5**	**$9.7**	**$4.5**	**$4.4**
After-Tax Net Equity Cash Flow – (I) + (M) + (P) = (Q)	**($68.0)**	**$16.5**	**$24.5**	**$15.7**	**$10.3**	**$10.2**
IRR For Equity Investors	12.0%					

Key Assumptions[c]	
Capacity (MW)	100
Capacity Factor	38%
Fuel Cost ($/MMBtu)[d]	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$40.0
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years)[e]	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,100
Additional Owner's Costs ($/kW)	$600
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,700
Total Capex ($mm)	$170

Source: *Lazard estimates.*
Note: Wind—High LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(a) Assumes half-year convention for discounting purposes.
(b) Assumes full monetization of tax benefits of losses immediately.
(c) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(d) Fuel costs converted from relevant source to $/MMBtu for conversion purposes.
(e) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on 20-year IRR basis.

Technology-dependent

Levelized

Ex. AA-D-20

Levelized Cost of Energy—Key Assumptions

	Units	Solar PV: Rooftop—Residential		Solar PV: Rooftop—C&I		Solar PV: Community		Solar PV: Utility Scale—Crystalline(c)		Solar PV: Utility Scale—Thin Film(c)		Solar Thermal Tower with Storage(d)	
Net Facility Output	MW	0.005	0.002	1		1.5		30		30		110	
EPC Cost	$/kW	$2,000	$2,800	$2,100	$3,750	$2,000	$2,800	$1,450	$1,300	$1,450	$1,300	$9,000	$8,750
Capital Cost During Construction	$/kW	—		—		—		—		—		$1,300	$1,250
Other Owner's Costs	$/kW	included		included		included		included		included		included	
Total Capital Cost(a)	$/kW	$2,000	$2,800	$2,100	$3,750	$2,000	$2,800	$1,450	$1,300	$1,450	$1,300	$10,300	$10,000
Fixed O&M	$/kW-yr	$20.00	$25.00	$15.00	$20.00	$12.00	$16.00	$12.00	$9.00	$12.00	$9.00	$115.00	$80.00
Variable O&M	$/MWh	—		—		—		—		—		—	
Heat Rate	Btu/kWh	—		—		—		—		—		—	
Capacity Factor	%	18%	15%	25%	20%	25%	20%	30%	21%	32%	23%	85%	52%
Fuel Price	$/MMBtu	0		0		0		0		0		0	
Construction Time	Months	3		3		6		9		9		36	
Facility Life	Years	20		25		30		30		30		35	
CO_2 Emissions	lb/MMBtu	—		—		—		—		—		—	
Levelized Cost of Energy(b)	$/MWh	$138	$222	$88	$193	$78	$135	$49	$61	$46	$56	$119	$182

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 – 10.0 present LCOE on an unsubsidized basis.
(c) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.
(d) Left column represents concentrating solar tower with 18-hour storage capability. Right column represents concentrating solar tower with 10-hour storage capability.

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

	Units	Fuel Cell	Microturbine	Geothermal	Biomass Direct	Wind—On Shore	Wind—Off Shore
Net Facility Output	MW	2.4	1 0.25	20	35	100	210 385
EPC Cost	$/kW	$3,000 - $7,500	$2,500 - $2,700	$3,700 - $5,600	$2,200 - $3,500	$950 - $1,100	$2,750 - $4,500
Capital Cost During Construction	$/kW	—	—	$550 - $800	$300 - $500	—	—
Other Owner's Costs	$/kW	$800 - $0	included	included	included	$300 - $600	included
Total Capital Cost[a]	$/kW	$3,800 - $7,500	$2,500 - $2,700	$4,250 - $6,400	$2,500 - $4,000	$1,250 - $1,700	$2,750 - $4,500
Fixed O&M	$/kW-yr	—	$6.85 - $9.12	—	$95.00	$35.00 - $40.00	$80.00 - $110.00
Variable O&M	$/MWh	$30.00 - $50.00	$7.00 - $10.00	$30.00 - $40.00	$15.00	—	—
Heat Rate	Btu/kWh	7,260 - 6,600	10,300 - 12,000	—	14,500	—	—
Capacity Factor	%	95%	95%	90% - 85%	85%	55% - 38%	48% - 40%
Fuel Price	$/MMBtu	3.45	$3.45	—	$1.00 - $2.00	—	—
Construction Time	Months	3	3	36	36	12	12
Facility Life	Years	20	20	25	25	20	20
CO_2 Emissions	lb/MMBtu	0 - 117	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$106 - $167	$76 - $89	$79 - $117	$77 - $110	$32 - $62	$82 - $155

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 – 10.0 present LCOE on an unsubsidized basis.

Ex. AA-D-20

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

	Units	Diesel Reciprocating Engine[c]	Natural Gas Reciprocating Engine	Gas Peaking	IGCC[d]	Nuclear[e]	Coal[f]	Gas Combined Cycle
Net Facility Output	MW	0.25	0.25	216 - 103	580	1,100	600	550
EPC Cost	$/kW	$500 - $800	$650 - $1,100	$580 - $700	$3,300 - $11,600	$3,800 - $5,300	$2,000 - $6,100	$750 - $1,000
Capital Cost During Construction	$/kW	—	—	—	$700 - $2,900	$1,000 - $1,400	$500 - $1,600	$100 - $100
Other Owner's Costs	$/kW	included	included	$220 - $300	$0 - $0	$600 - $1,500	$500 - $700	$200 - $200
Total Capital Cost[a]	$/kW	$500 - $800	$650 - $1,100	$800 - $1,000	$4,000 - $14,500	$5,400 - $8,200	$3,000 - $8,400	$1,000 - $1,300
Fixed O&M	$/kW-yr	$15.00	$15.00 - $20.00	$5.00 - $25.00	$62.25 - $73.00	$135.00	$40.00 - $80.00	$6.20 - $5.50
Variable O&M	$/MWh	$15.00	$10.00 - $15.00	$4.70 - $7.50	$7.00 - $8.50	$0.50 - $0.75	$2.00 - $5.00	$3.50 - $2.00
Heat Rate	Btu/kWh	10,000	8,000 - 9,000	10,300 - 9,000	8,800 - 11,700	10,450	8,750 - 12,000	6,300 - 6,900
Capacity Factor	%	95% - 10%	95% - 30%	10%	75%	90%	93%	80% - 40%
Fuel Price	$/MMBtu	$18.23	$5.50	$3.45	$1.33 - $0.65	$0.85	$1.47	$3.45
Construction Time	Months	3	3	25	57 - 63	69	60 - 66	36
Facility Life	Years	20	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 - 117	117	117	169	—	211	117
Levelized Cost of Energy[b]	$/MWh	$212 - $281	$68 - $101	$165 - $217	$94 - $210	$97 - $136	$60 - $143	$48 - $78

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 – 10.0 present LCOE on an unsubsidized basis.
(c) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of ~$2.50 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) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail 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, etc.) 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 other important metrics on the levelized cost of energy. These inputs were originally 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 benefited 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.).

NOVEMBER 2019

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 13.0

LAZARD

Introduction

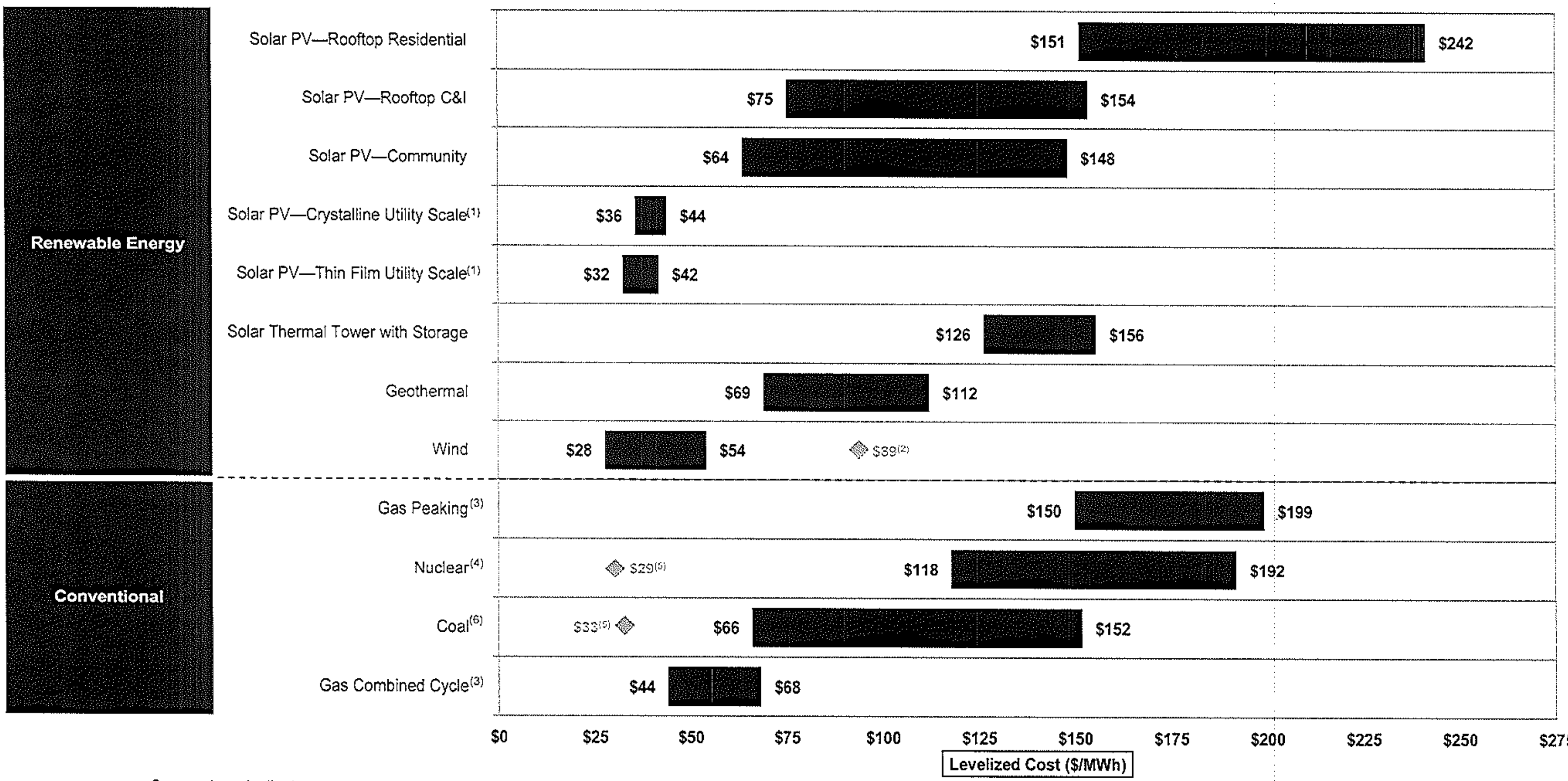
Lazard's Levelized Cost of Energy ("LCOE") analysis addresses the following topics:

- **Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities for U.S. federal tax subsidies, fuel prices and costs of capital**
- **Illustration of how the LCOE of onshore wind and utility-scale solar compare to the marginal cost of selected conventional generation technologies**
- **Historical LCOE comparison of various utility-scale generation technologies**
- **Illustration of the historical LCOE declines for wind and utility-scale solar technologies**
- **Illustration of how the LCOEs of utility-scale solar and wind compare to those of gas peaking and combined cycle**
- **Comparison of capital costs on a $/kW basis for various generation technologies**
- **Deconstruction of the LCOE for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense and fuel cost**
- **Overview of the methodology utilized to prepare Lazard's LCOE analysis**
- **Considerations regarding the operating characteristics and applications of various generation technologies**
- **An illustrative comparison of the value of carbon abatement of various renewable energy technologies**
- **Summary of assumptions utilized in Lazard's LCOE analysis**
- **Summary considerations in respect of Lazard's approach to evaluating the LCOE of various conventional and renewable energy 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; network upgrades, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed 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, airborne pollutants, greenhouse gases, etc.)

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Selected renewable energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances



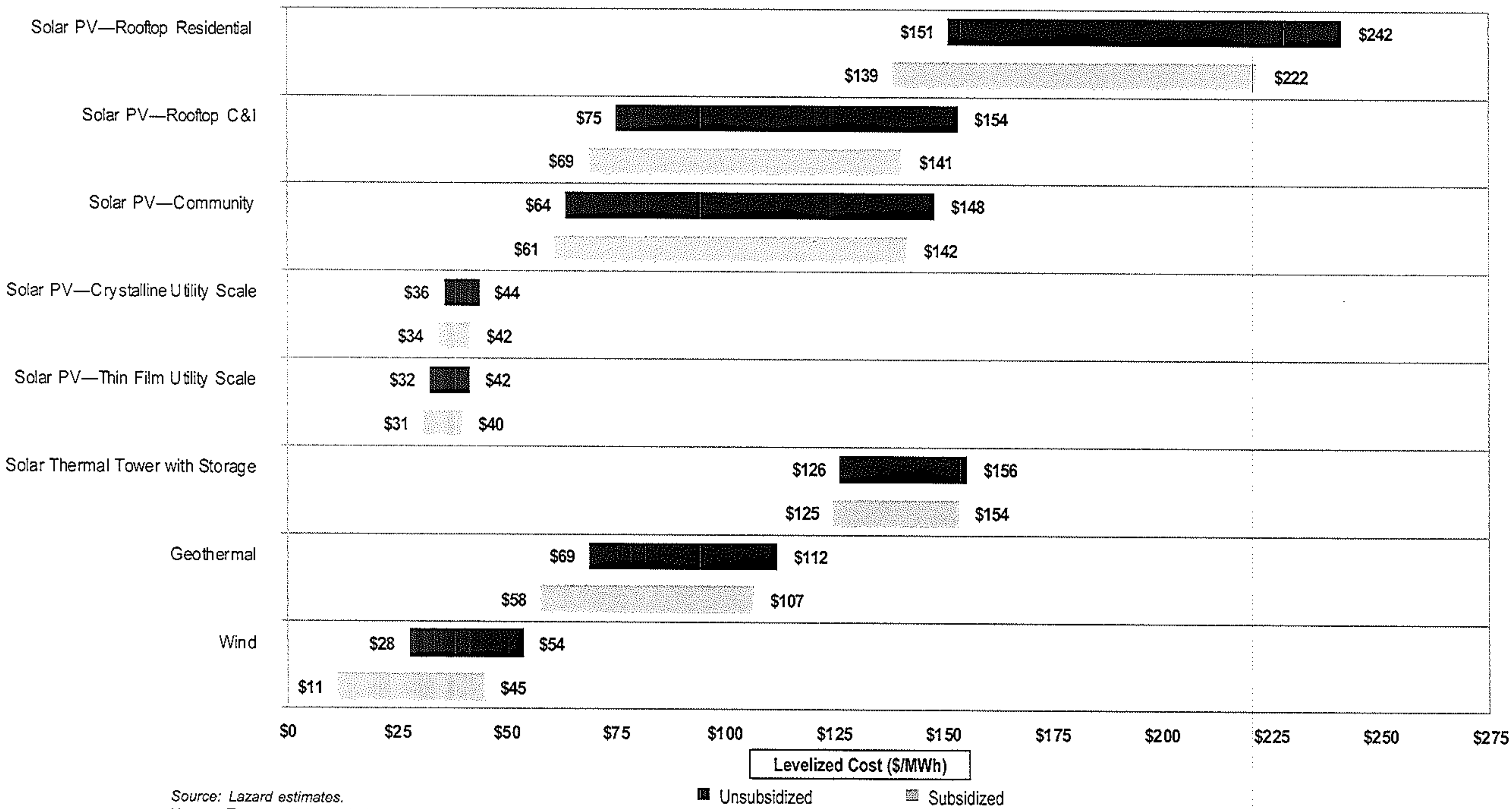
Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities. These results are not intended to represent any particular geography. Please see page titled "Solar PV versus Gas Peaking and Wind versus CCGT—Global Markets" for regional sensitives to selected technologies.

(1) Unless otherwise indicated herein, the low end represents a single-axis tracking system and the high end represents a fixed-tilt system.
(2) Represents the estimated implied midpoint of the LCOE of offshore wind, assuming a capital cost range of approximately $2.33 – $3.53 per watt.
(3) The fuel cost assumption for Lazard's global, unsubsidized analysis for gas-fired generation resources is $3.45/MMBTU.
(4) Unless otherwise indicated, the analysis herein does not reflect decommissioning costs, ongoing maintenance-related capital expenditures or the potential economic impacts of federal loan guarantees or other subsidies.
(5) Represents the midpoint of the marginal cost of operating coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating coal and nuclear assets across the U.S. Capacity factors, fuel and variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research. Please see page titled "Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation" for additional details.
(6) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies(1)

The Investment Tax Credit ("ITC") and Production Tax Credit ("PTC"), extended in December 2015, remain an important component of the levelized cost of renewable energy generation technologies



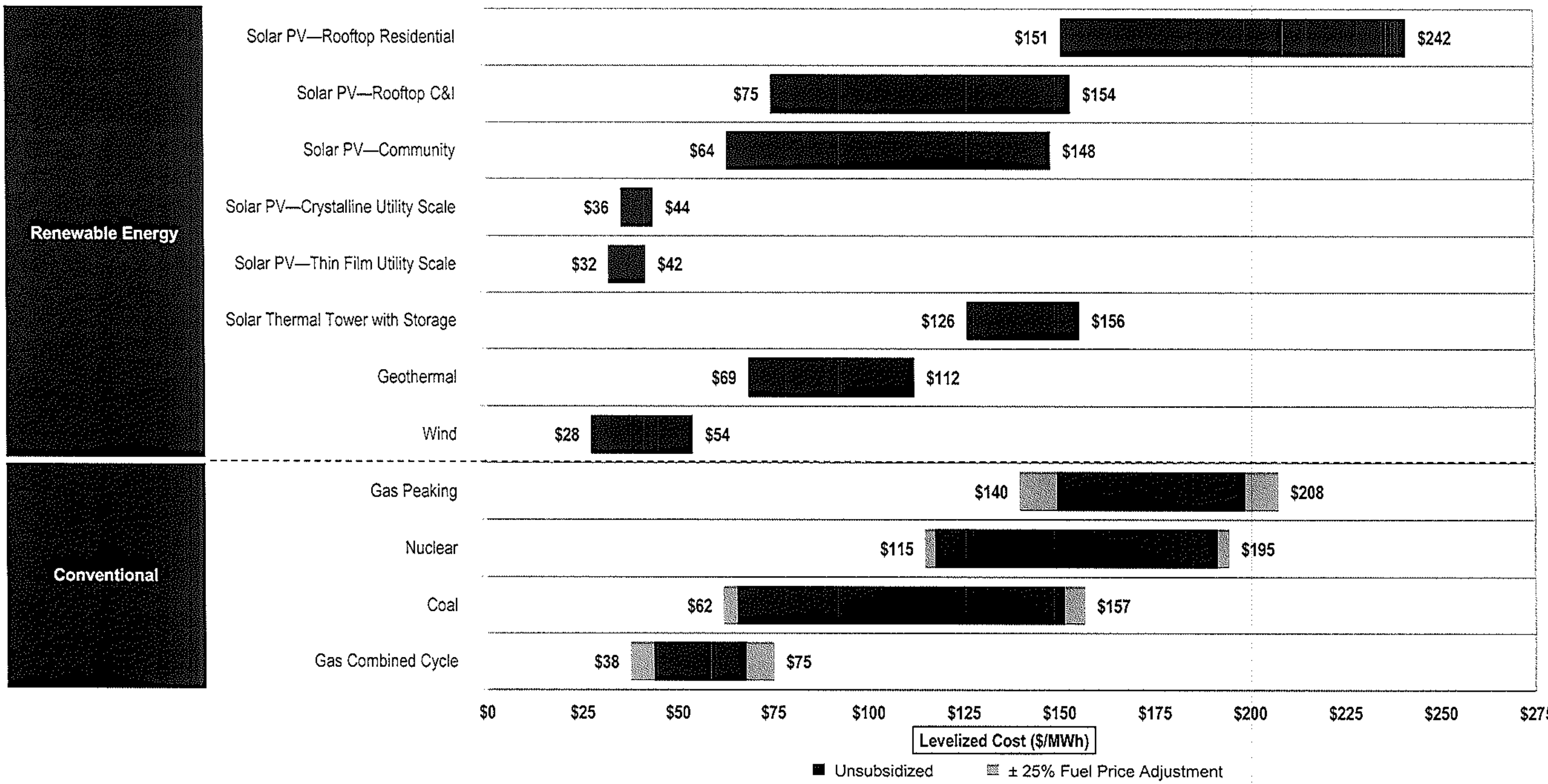
Source: *Lazard estimates.*

Note: The sensitivity analysis presented on this page also includes sensitivities related to the U.S. Tax Cuts and Jobs Act ("TCJA") of 2017. The TCJA contains several provisions that impact the LCOE of various generation technologies (e.g., a reduced federal corporate income tax rate, an ability to elect immediate bonus depreciation, limitations on the deductibility of interest expense and restrictions on the utilization of past net operating losses). On balance, the TCJA reduced the LCOE of conventional generation technologies and marginally increased the LCOE for renewable energy technologies.

(1) The sensitivity analysis presented on this page assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, tax equity and debt.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the LCOE of conventional generation technologies, but direct comparisons to "competing" renewable energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. those of peaking or intermittent technologies)

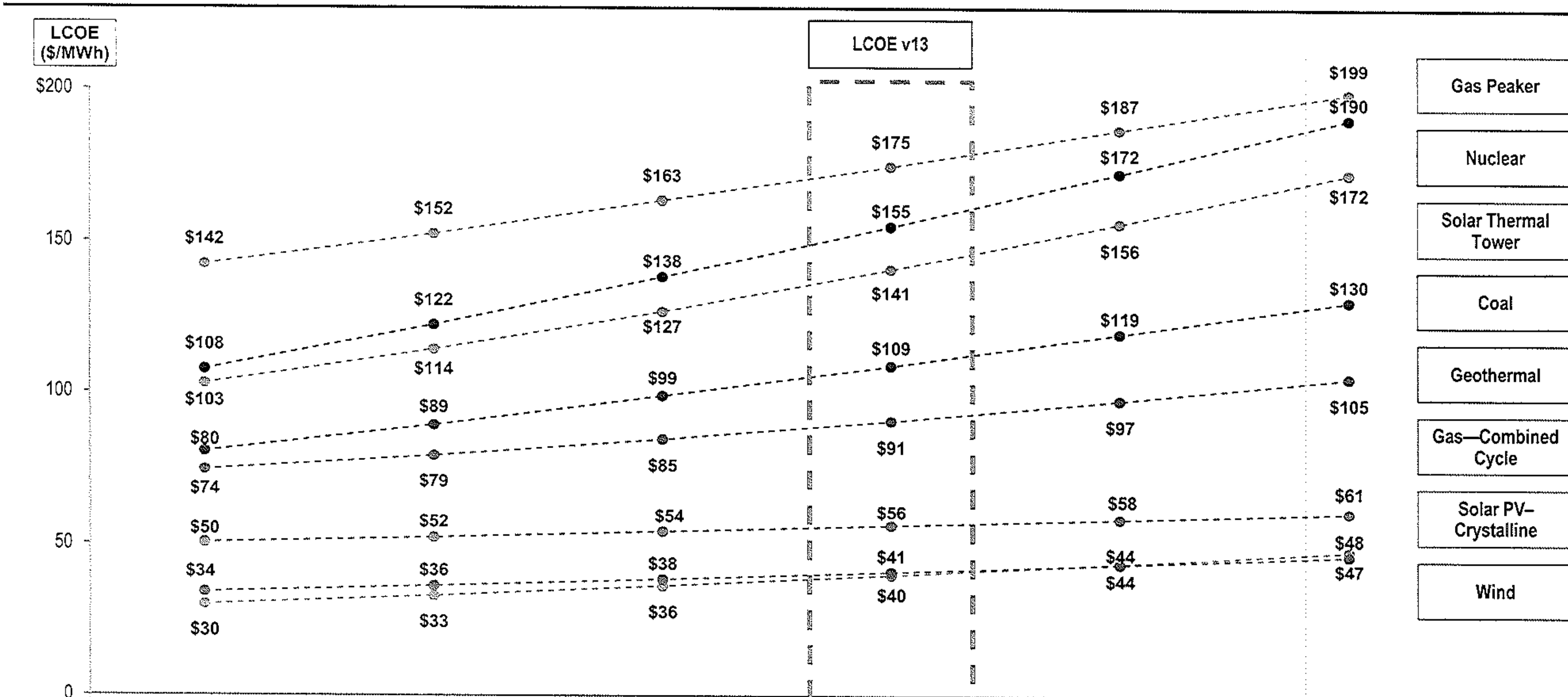


Source: *Lazard estimates.*
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the global, unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration in determining the LCOE values for utility-scale generation technologies is the cost, and availability, of capital[1]; this dynamic is particularly significant for renewable energy generation technologies

Midpoint of Unsubsidized LCOE[2]



After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Source: Lazard estimates.

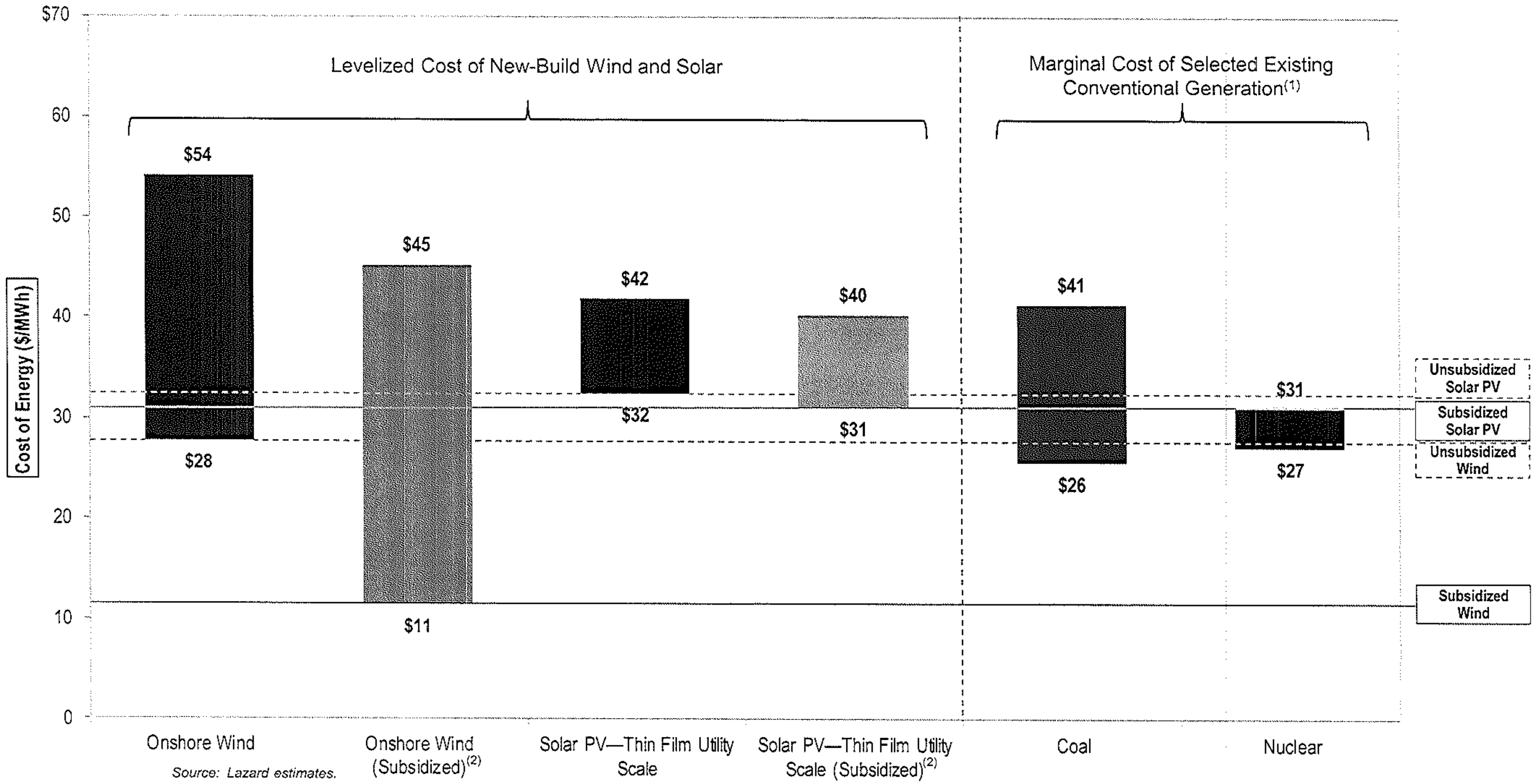
Note: Analysis assumes 60% debt and 40% equity. Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the global, unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Cost of capital as used herein indicates the cost of capital applicable to the asset/plant and not the cost of capital of a particular investor/owner.

(2) Reflects the average of the high and low LCOE for each respective cost of capital assumption.

Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation

Certain renewable energy generation technologies are approaching an LCOE that is competitive with the marginal cost of existing conventional generation



Source: Lazard estimates.

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the global, unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

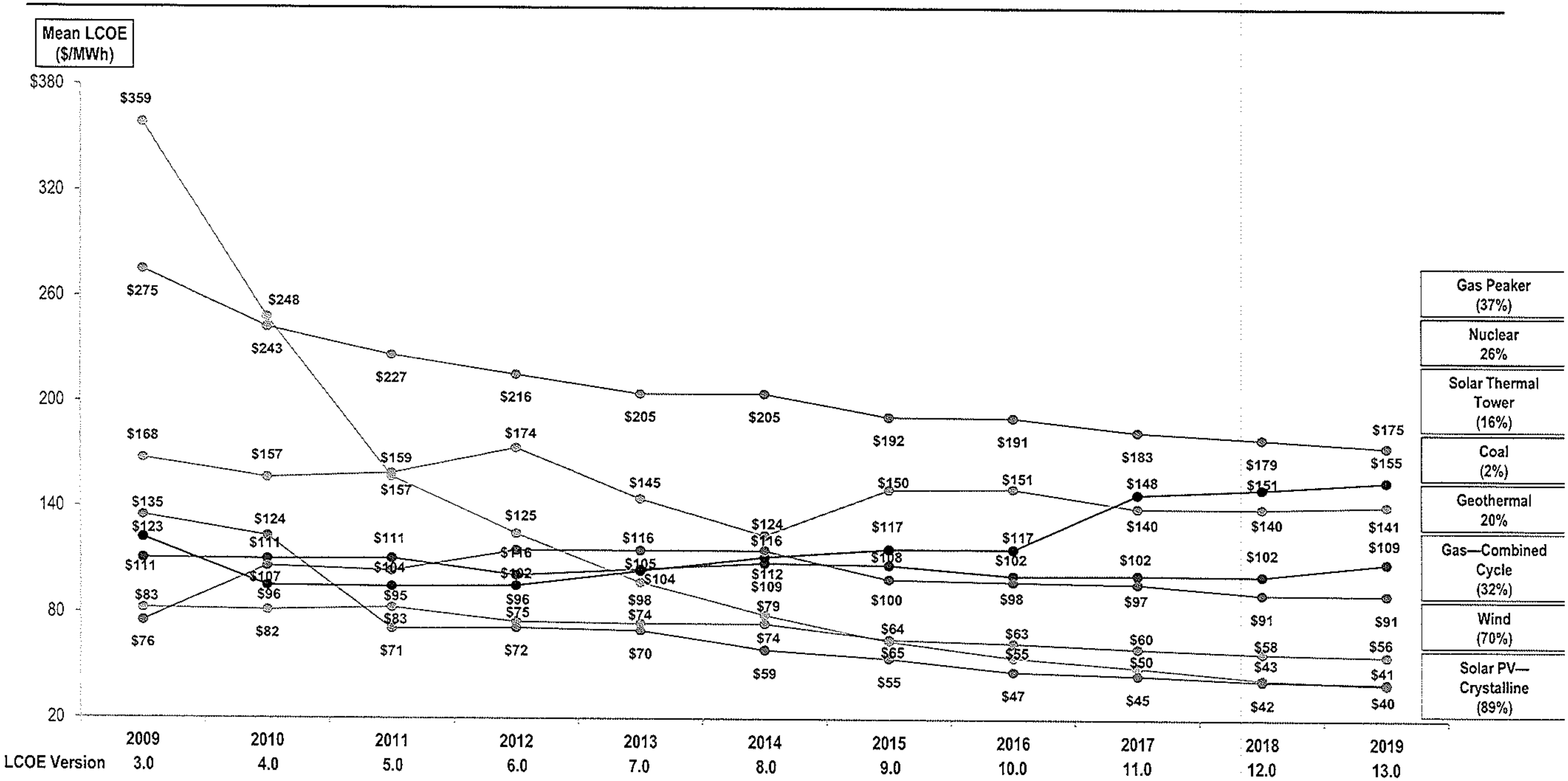
(1) Represents the marginal cost of operating coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating coal and nuclear assets across the U.S. Capacity factors, fuel and variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research.

(2) The subsidized analysis includes sensitivities related to the TCJA and U.S. federal tax subsidies. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

Levelized Cost of Energy Comparison—Historical Utility-Scale Generation Comparison

Lazard's unsubsidized LCOE analysis indicates significant historical cost declines for utility-scale renewable energy generation technologies driven by, among other factors, decreasing capital costs, improving technologies and increased competition

Selected Historical Mean Unsubsidized LCOE Values(1)



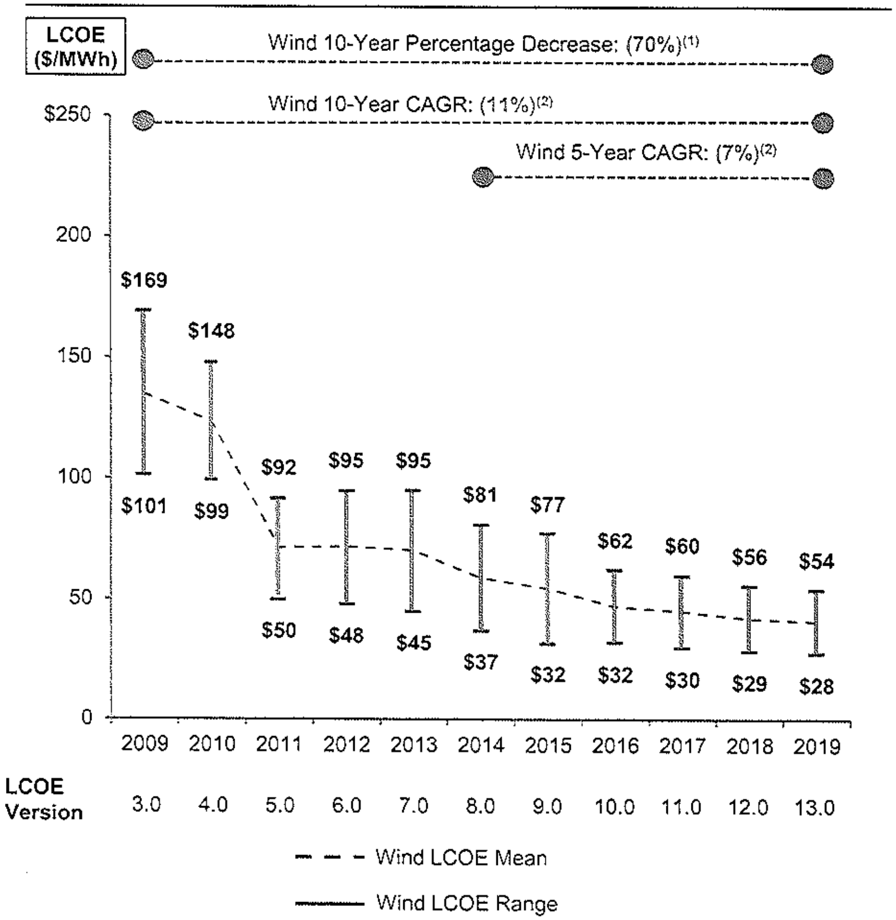
Source: Lazard estimates.

(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE—Version 3.0.

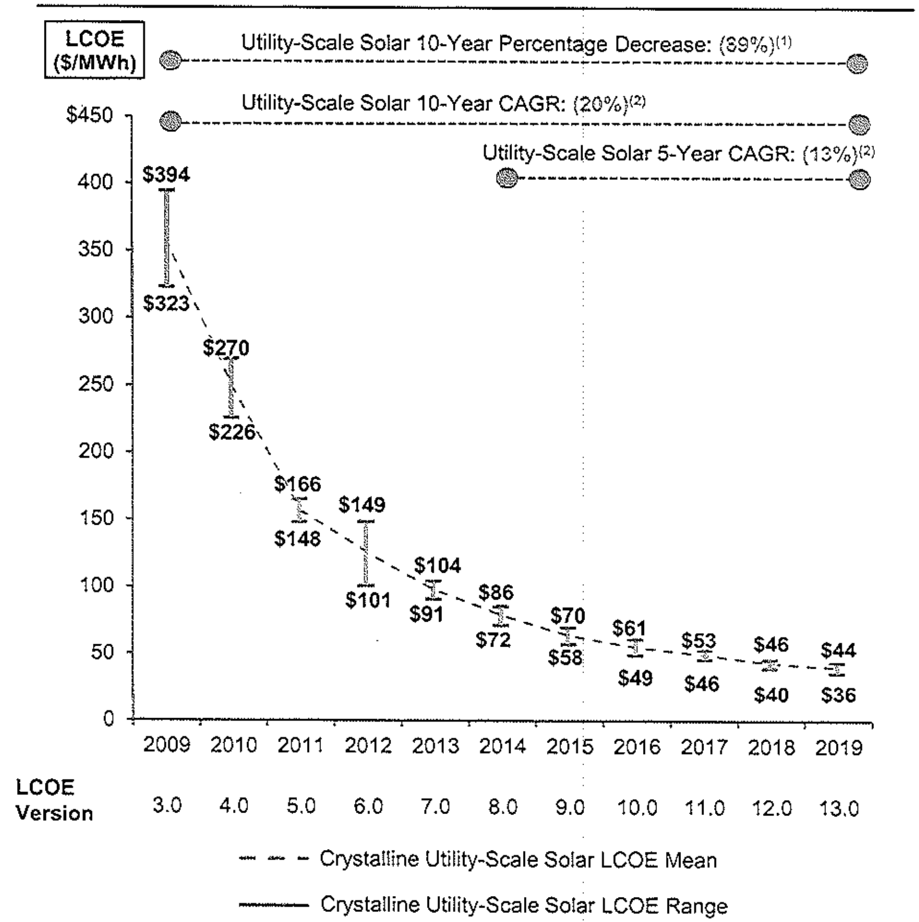
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE Declines

In light of material declines in the pricing of system components and improvements in efficiency, among other factors, wind and utility-scale solar PV have exhibited dramatic LCOE declines; however, as these industries mature, the rates of decline have diminished

Unsubsidized Wind LCOE



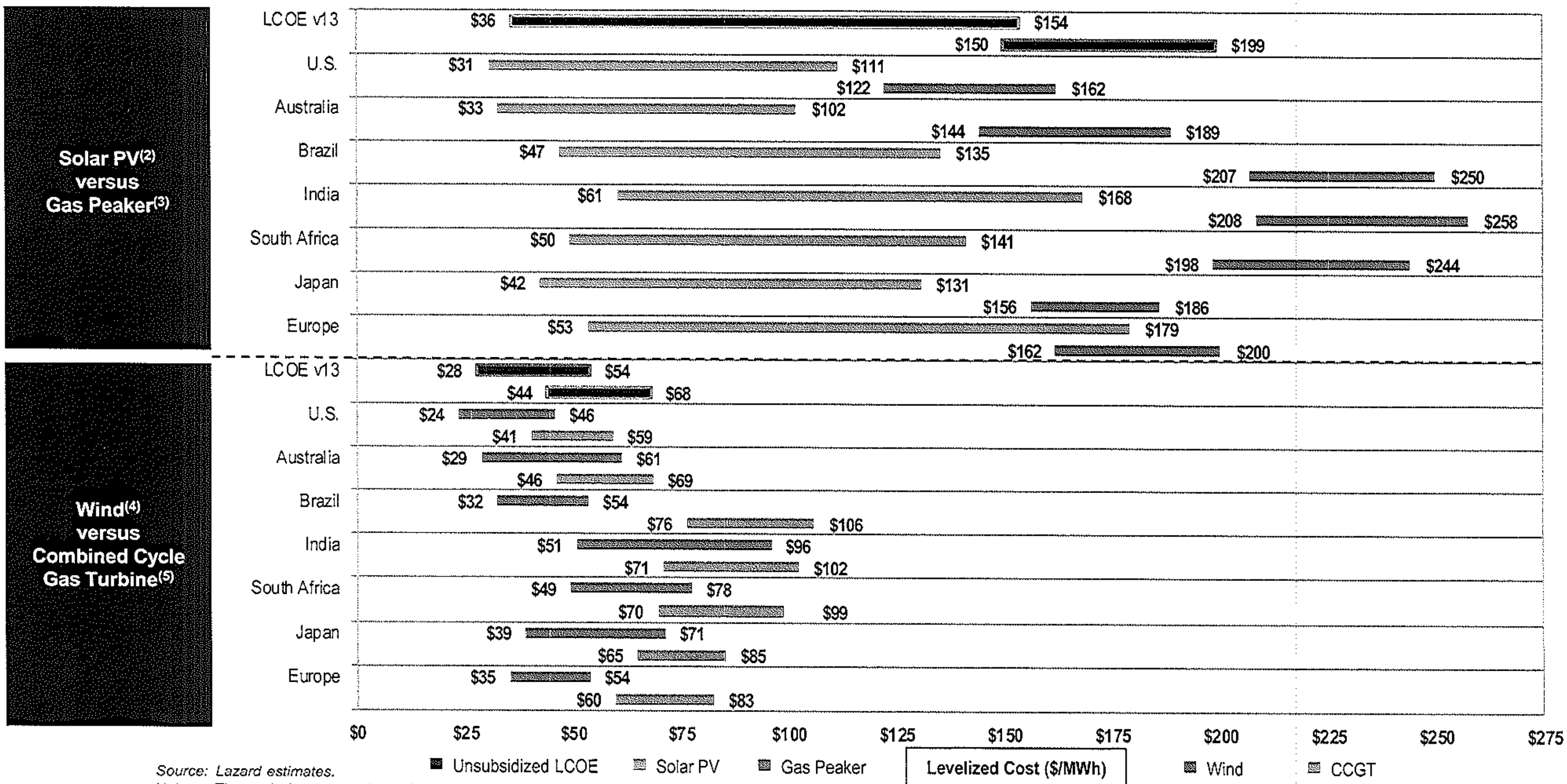
Unsubsidized Solar PV LCOE



Source: Lazard estimates.
(1) Represents the average percentage decrease of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Solar PV versus Gas Peaking and Wind versus CCGT—Global Markets(1)

Solar PV and wind have become increasingly competitive with conventional technologies with similar generation profiles; without storage, however, these resources lack the dispatch characteristics, and associated benefits, of such conventional technologies



Source: *Lazard estimates.*
Note: The analysis presented on this page assumes country-specific or regionally-applicable tax rates.

(1) Equity IRRs are assumed to be 10.0% – 12.0% for Australia, 15.0% for Brazil and South Africa, 13.0% – 15.0% for India, 8.0% – 10.0% for Japan, 7.5% – 12.0% for Europe and 7.5% – 9.0% for the U.S. Cost of debt is assumed to be 5.0% – 5.5% for Australia, 10.0% – 12.0% for Brazil, 12.0% – 13.0% for India, 3.0% for Japan, 4.5% – 5.5% for Europe, 12.0% for South Africa and 4.0% – 4.5% for the U.S.

(2) Low end assumes crystalline utility-scale solar with a single-axis tracker. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 21% – 28% for the U.S., 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Europe.

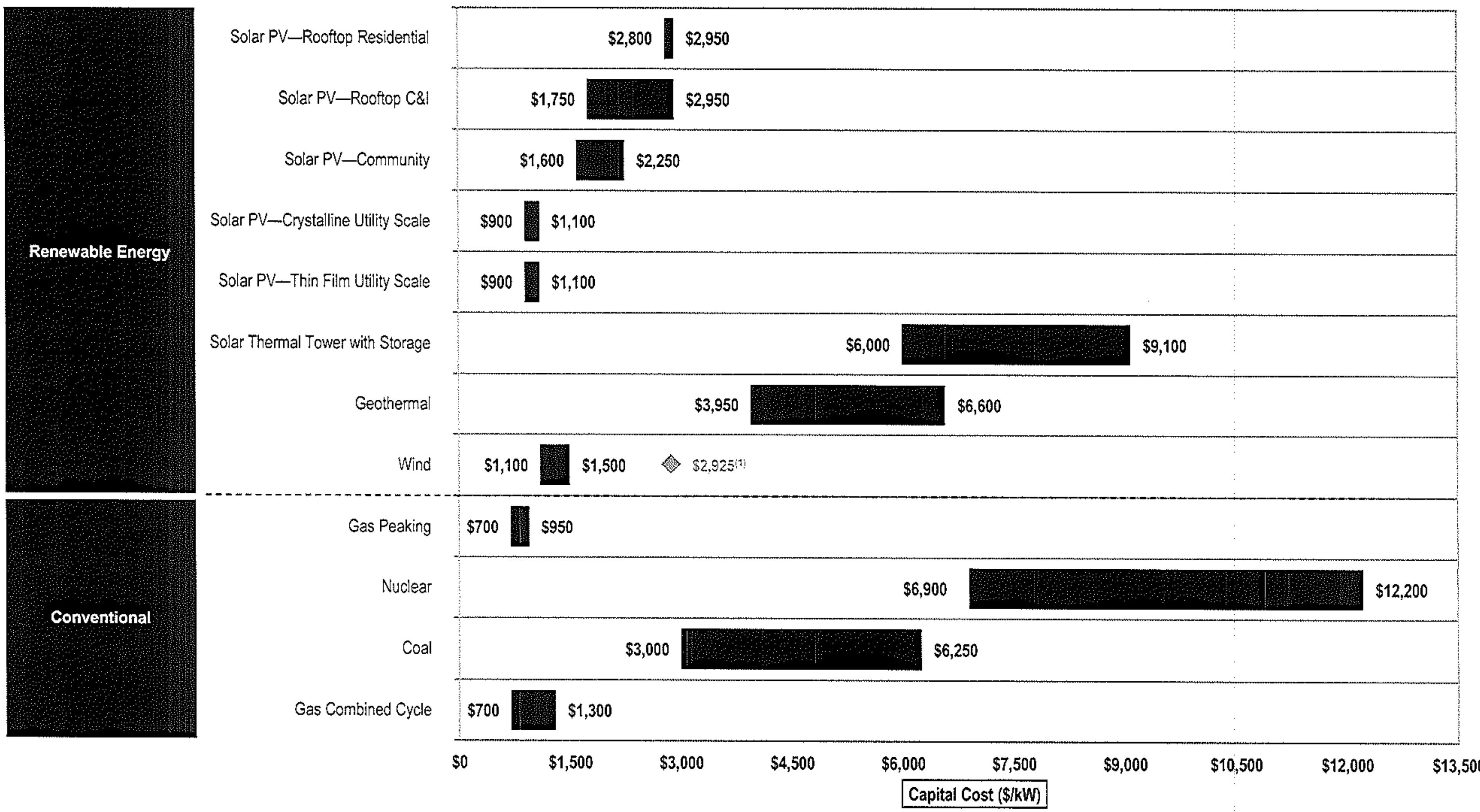
(3) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10% for all geographies.

(4) Wind projects assume illustrative capacity factors of 38% – 55% for the U.S., 29% – 46% for Australia, 45% – 55% for Brazil, 25% – 35% for India, 31% – 36% for South Africa, 22% – 30% for Japan and 33% – 38% for Europe.

(5) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Europe (all in U.S.$ per MMBtu). Assumes capacity factors of 55% – 70% on the high and low ends, respectively, for all geographies.

Capital Cost Comparison

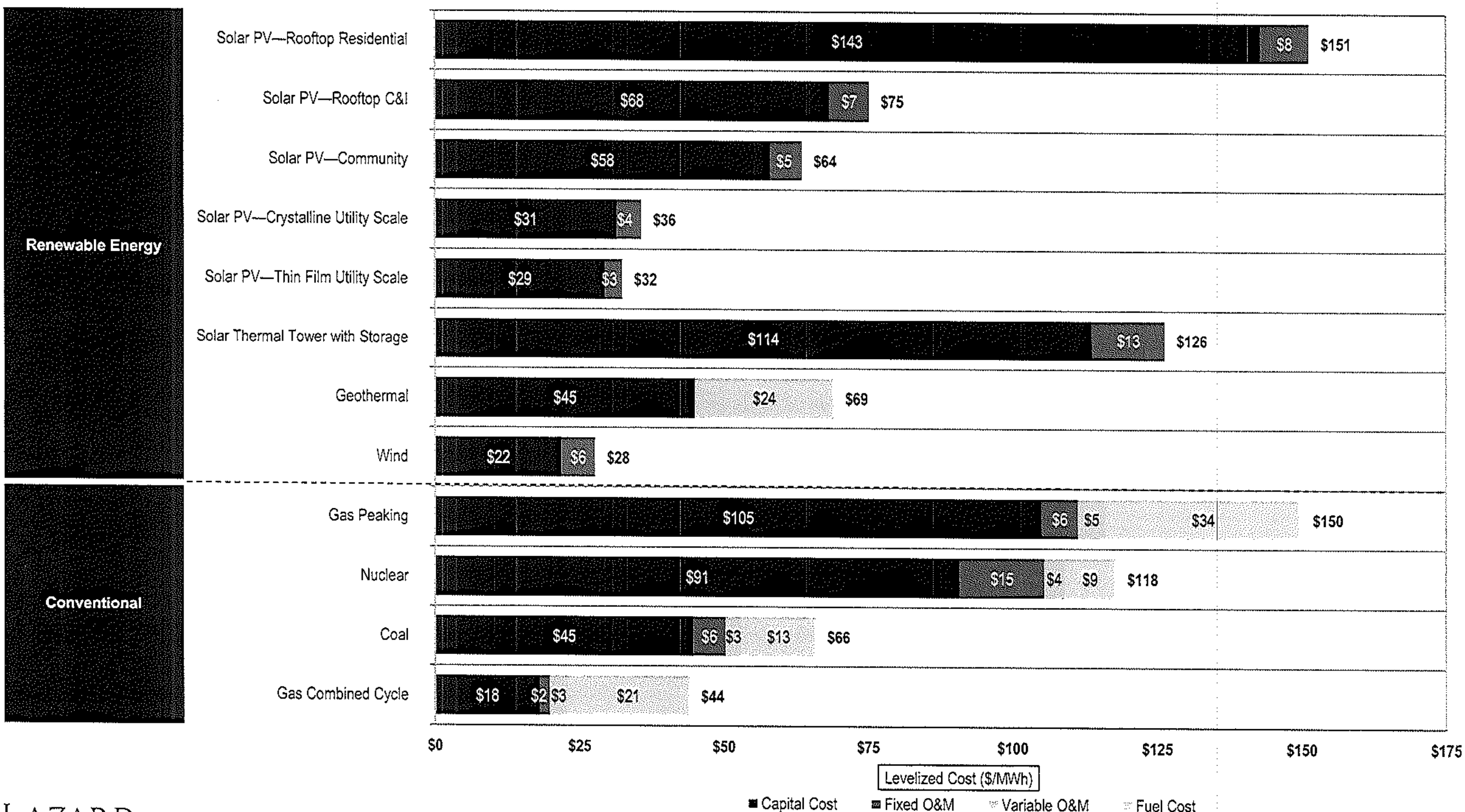
In some instances, the capital costs of renewable energy generation technologies have converged with those of certain conventional generation technologies, which coupled with improvements in operational efficiency for renewable energy technologies, have led to a convergence in LCOE between the respective technologies



Source: *Lazard estimates.*
(1) Represents the estimated midpoint of the total capital cost for offshore wind.

Levelized Cost of Energy Components—Low End

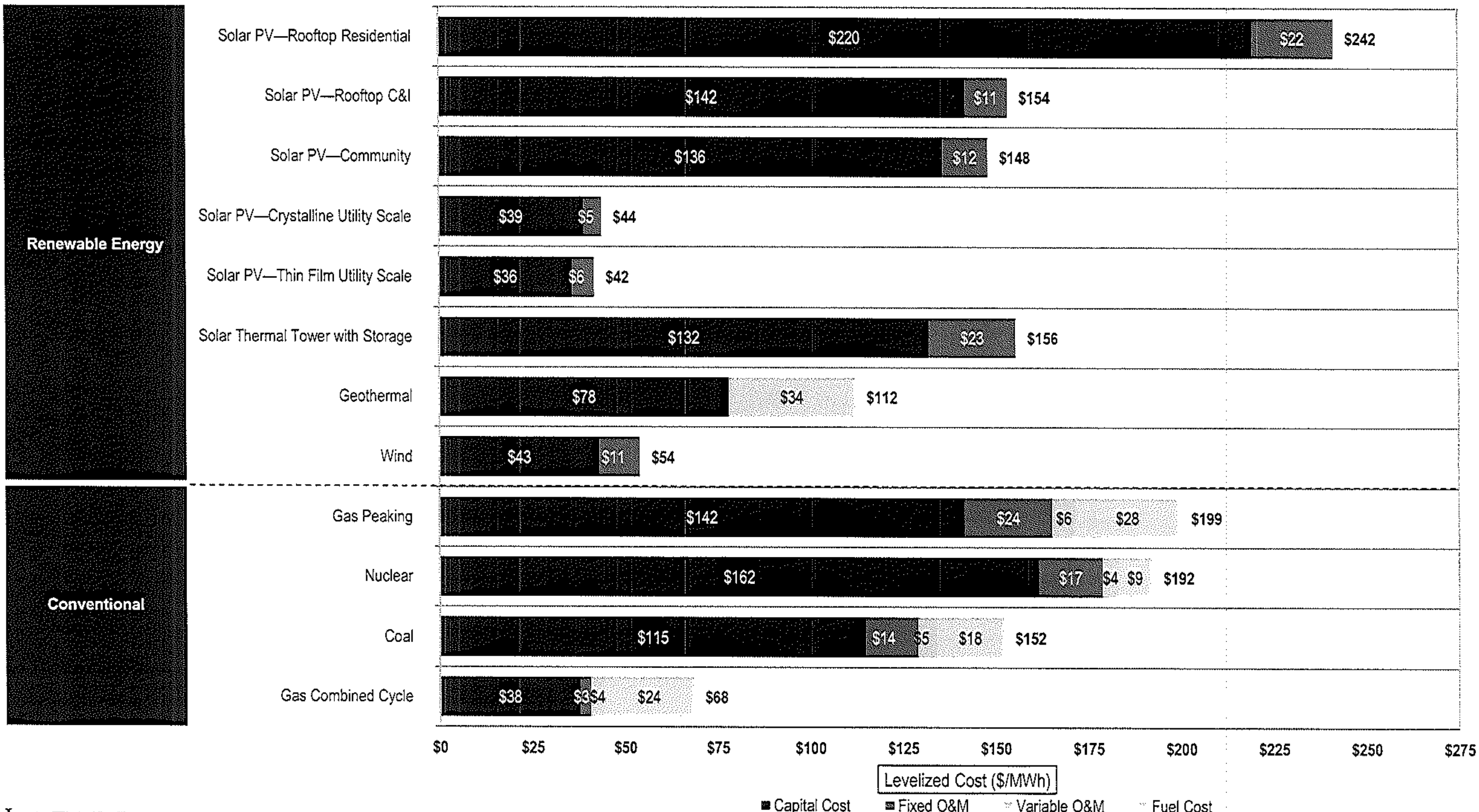
Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the continued cost decline of renewable energy generation technologies is the ability of technological development and industry scale to continue lowering operating expenses and capital costs for renewable energy generation technologies



Source: Lazard estimates.

Levelized Cost of Energy Components—High End

Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the continued cost decline of renewable energy generation technologies is the ability of technological development and industry scale to continue lowering operating expenses and capital costs for renewable energy generation technologies



Source: Lazard estimates.

Levelized Cost of Energy Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOE analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" pages for detailed assumptions by technology)

Unsubsidized Wind — High Case Sample Illustrative Calculations

Year[1]		0	1	2	3	4	5		20
Capacity (MW)	(A)		150	150	150	150	150		150
Capacity Factor	(B)		38%	38%	38%	38%	38%		38%
Total Generation ('000 MWh)	(A) x (B) = (C)*		499	499	499	499	499		499
Levelized Energy Cost ($/MWh)	*(D)*		*$54.1*	*$54.1*	*$54.1*	*$54.1*	*$54.1*		*$54.1*
Total Revenues	(C) x (D) = (E)*		**$27.0**	**$27.0**	**$27.0**	**$27.0**	**$27.0**		**$27.0**
Total Fuel Cost	(F)		--	--	--	--	--		--
Total O&M	(G)*		5.4	5.6	5.7	5.8	5.9		8.5
Total Operating Costs	(F) + (G) = (H)		**$5.4**	**$5.6**	**$5.7**	**$5.8**	**$5.9**		$8.5
EBITDA	(E) - (H) = (I)		**$21.6**	**$21.5**	**$21.3**	**$21.2**	**$21.1**		**$18.5**
Debt Outstanding - Beginning of Period	(J)		$135.0	$132.3	$129.4	$126.3	$122.9		$12.5
Debt - Interest Expense	(K)		(10.8)	(10.6)	(10.4)	(10.1)	(9.8)		(1.0)
Debt - Principal Payment	(L)		(2.7)	(2.9)	(3.1)	(3.4)	(3.6)		(12.5)
Levelized Debt Service	(K) + (L) = (M)		($13.5)	($13.5)	($13.5)	($13.5)	($13.5)		($13.5)
EBITDA	(I)		$21.6	$21.5	$21.3	$21.2	$21.1		$18.5
Depreciation (MACRS)	(N)		(45.0)	(72.0)	(43.2)	(25.9)	(25.9)		--
Interest Expense	(K)		(10.8)	(10.6)	(10.4)	(10.1)	(9.8)		(1.0)
Taxable Income	(I) + (N) + (K) = (O)		**($34.2)**	**($61.1)**	**($32.2)**	**($14.8)**	**($14.7)**		**$17.5**
Tax Benefit (Liability)[2]	(O) x (tax rate) = (P)		**$13.7**	**$24.5**	**$12.9**	**$5.9**	**$5.9**		**($7.0)**
After-Tax Net Equity Cash Flow	(I) + (M) + (P) = (Q)	($90.0)[3]	**$21.8**	**$32.4**	**$20.7**	**$13.7**	**$13.5**		**($2.0)**
IRR For Equity Investors		12.0%							

Key Assumptions[4]	
Capacity (MW)	150
Capacity Factor	38%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$36.5
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years)[5]	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,500
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,500
Total Capex ($mm)	$225

Technology-dependent

Levelized

Source: *Lazard estimates.*
Note: Wind—High LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Assumes full monetization of tax benefits or losses immediately.
(3) Reflects initial cash outflow from equity investors.
(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

Energy Resources—Matrix of Applications

Despite convergence in the LCOE between certain renewable energy and conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. those of peaking or intermittent technologies)

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

		Carbon Neutral/ REC Potential	Location			Dispatch			
			Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Baseload
Renewable Energy	Solar PV[1]	✓	✓	✓	Universal[2]	✓	✓		
	Solar Thermal	✓		✓	Rural	✓	✓	✓	
	Geothermal	✓		✓	Varies				✓
	Onshore Wind	✓		✓	Rural	✓			
Conventional	Gas Peaking	×	✓	✓	Universal		✓	✓	
	Nuclear	✓		✓	Rural				✓
	Coal	×		✓	Co-located or rural				✓
	Gas Combined Cycle	×		✓	Universal			✓	✓

Source: Lazard estimates.
(1) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(2) Qualification for RPS requirements varies by location.

Value of Carbon Abatement Comparison

As policymakers consider ways to limit carbon emissions, Lazard's LCOE analysis provides insight into the economic value associated with carbon abatement offered by renewable energy technologies. This analysis suggests that policies designed to shift power generation towards wind and utility-scale solar could be a particularly cost-effective means of reducing carbon emissions, providing an abatement value of $36 – $41/Ton vs. Coal and $23 – $32/Ton vs. Gas Combined Cycle

- **These observations do not take into account other environmental and social externalities, reliability or grid-related considerations**

		Conventional Generation			Renewable Energy Generation			
	Units	Coal	Gas Combined Cycle	Nuclear	Wind	Solar PV Rooftop	Solar PV Utility Scale	Solar Thermal with Storage
Capital Investment/KW of Capacity [1]	$/kW	$2,975	$700	$6,900	$1,100	$2,800	$900	$9,100
Total Capital Investment	**$mm**	**1,993**	**560**	**4,209**	**1,111**	**8,232**	**1,476**	**7,462**
Facility Output	MW	670	800	610	1,010	2,940	1,640	820
Capacity Factor	%	83%	70%	91%	55%	19%	34%	68%
MWh/Year Produced [2]	**GWh/yr**	**4,888**	**4,888**	**4,888**	**4,888**	**4,888**	**4,888**	**4,888**
Levelized Cost of Energy	$/MWh	$66	$44	$118	$28	$151	$32	$126
Total Cost of Energy Produced	**$mm/yr**	**$322** 2	**$215**	**$576**	**$136** 1	**$740**	**$159**	**$618**
CO_2 Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51 3	4.51	4.51	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($107)	$254	($187) 4	$418	($163)	$296
vs. Gas		—	—	$361	($80)	$525	($56)	$403
Implied Abatement Value/(Cost)	$/Ton							
vs. Coal		—	$53	($56)	$41 5	($93)	$36	($66)
vs. Gas		—	—	($144)	$32	($210)	$23	($161)

: Favorable vs. Coal/Gas : Unfavorable vs. Coal/Gas

Implied Carbon Abatement Value Calculation (Wind vs. Coal)—Methodology

4 Difference in Total Energy Cost (Wind vs. Coal) = 1 – 2 = $136 mm/yr (Wind) – $322 mm/yr (Coal) = ($187) mm/yr

5 Implied Carbon Abatement Value (Wind vs. Coal) = 4 ÷ 3 = $187 mm/yr ÷ 4.51 mm Tons/yr = $41/Ton

LAZARD

Source: Lazard estimates.
(1) Assumptions utilized for the technologies presented in this analysis correspond to those associated with the Low LCOE cases.
(2) All facilities illustratively sized to produce 4,888 GWh/yr.

Levelized Cost of Energy—Key Assumptions

		Solar PV				
	Units	Rooftop—Residential	Rooftop—C&I	Community	Utility Scale—Crystalline (2)	Utility Scale—Thin Film (2)
Net Facility Output	MW	0.005	1	5	100	100
EPC Cost	$/kW	$2,800 – $2,950	$1,750 – $2,950	$1,600 – $2,250	$1,100 – $900	$1,100 – $900
Capital Cost During Construction	$/kW	—	—	—	—	—
Other Owner's Costs	$/kW	included	included	included	included	included
Total Capital Cost (1)	$/kW	$2,800 – $2,950	$1,750 – $2,950	$1,600 – $2,250	$1,100 – $900	$1,100 – $900
Fixed O&M	$/kW-yr	$14.00 – $25.00	$15.00 – $20.00	$12.00 – $16.00	$12.00 – $9.00	$12.00 – $9.00
Variable O&M	$/MWh	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—
Capacity Factor	%	19% – 13%	25% – 20%	25% – 15%	32% – 21%	34% – 23%
Fuel Price	$/MMBtu	—	—	—	—	—
Construction Time	Months	3	3	4 – 6	9	9
Facility Life	Years	25	25	30	30	30
Levelized Cost of Energy	$/MWh	$151 – $242	$75 – $154	$64 – $148	$36 – $44	$32 – $42

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design.

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

	Units	Solar Thermal Tower with Storage[2]	Geothermal	Wind—Onshore	Wind—Offshore
Net Facility Output	MW	110 – 150	20 – 50	150	210 – 385
EPC Cost	$/kW	$7,950 – $5,250	$3,450 – $5,750	$1,100 – $1,500	$2,350 – $3,550
Capital Cost During Construction	$/kW	$1,150 – $750	$500 – $850	—	—
Other Owner's Costs	$/kW	included	included	included	included
Total Capital Cost [1]	$/kW	$9,100 – $6,000	$3,950 – $6,600	$1,100 – $1,500	$2,350 – $3,550
Fixed O&M	$/kW-yr	$75.00 – $80.00	$0.00 – $0.00	$28.00 – $36.50	$80.00 – $110.00
Variable O&M	$/MWh	—	$24.00 – $34.00	—	—
Heat Rate	Btu/kWh	—	—	—	—
Capacity Factor	%	68% – 39%	90% – 85%	55% – 38%	55% – 45%
Fuel Price	$/MMBtu	—	—	—	—
Construction Time	Months	36	36	12	12
Facility Life	Years	35	25	20	20
Levelized Cost of Energy	$/MWh	$126 – $156	$69 – $112	$28 – $54	$64 – $115

Source: Lazard estimates.

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

(2) Left column represents the assumptions used to calculate the low end LCOE, representing a project with 18 hours of storage capacity. Right column represents the assumptions used to calculate the high end LCOE, representing a project with eight hours of storage.

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

	Units	Gas Peaking	Nuclear	Coal	Gas Combined Cycle
Net Facility Output	MW	240 – 50	2,200	600	550
EPC Cost	$/kW	$650 – $900	$5,400 – $9,600	$2,400 – $4,900	$650 – $1,200
Capital Cost During Construction	$/kW	—	—	—	—
Other Owner's Costs	$/kW	included	$1,500 – $2,650	$600 – $1,300	$50 – $100
Total Capital Cost [1]	$/kW	$700 – $950	$6,900 – $12,200	$3,000 – $6,250	$700 – $1,300
Fixed O&M	$/kW-yr	$5.50 – $20.75	$108.50 – $133.00	$40.75 – $81.75	$11.00 – $13.50
Variable O&M	$/MWh	$4.75 – $6.25	$3.50 – $4.25	$2.75 – $5.00	$3.00 – $3.75
Heat Rate	Btu/kWh	9,804 – 8,000	10,450 – 10,450	8,750 – 12,000	6,133 – 6,900
Capacity Factor	%	10%	91% – 90%	83% – 66%	70% – 55%
Fuel Price	$/MMBtu	$3.45 – $3.45	$0.85 – $0.85	$1.45 – $1.45	$3.45 – $3.45
Construction Time	Months	12 – 18	69 – 69	60 – 66	24 – 24
Facility Life	Years	20	40	40	20
Levelized Cost of Energy	$/MWh	$150 – $199	$118 – $192	$66 – $152	$44 – $68

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Summary Considerations

Lazard has conducted this analysis comparing the LCOE for various conventional and renewable energy generation technologies in order to understand which renewable energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions. We find that renewable energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including to mitigate the environmental and social consequences of various conventional generation technologies, RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase, and supportive regulatory frameworks in certain regions.

In this analysis, Lazard's approach was to determine the LCOE, 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, etc.) 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 other important metrics. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This analysis (as well as previous versions) has benefited from additional input from a wide variety of Industry participants and is informed by Lazard's many client interactions on this topic.

Lazard has not manipulated the cost of capital or capital structure for various technologies, as the goal of this analysis is to compare the current levelized cost of various generation technologies, rather than the benefits of financial engineering. The results contained herein would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or the cost of capital (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; network upgrades, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed 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, airborne pollutants, greenhouse gases, etc.).

Ex. AA-D-22

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 9.0

LAZARD

Ex. AA-D-22

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 for various generation technologies
- Illustration of how the cost of various generation technologies compares against illustrative generation rates in the largest metropolitan areas of the U.S.
- 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
- Illustration of the declines in the levelized cost of energy for various generation technologies over the past several years
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Illustration of the impact of cost of capital on the levelized cost of energy for selected 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

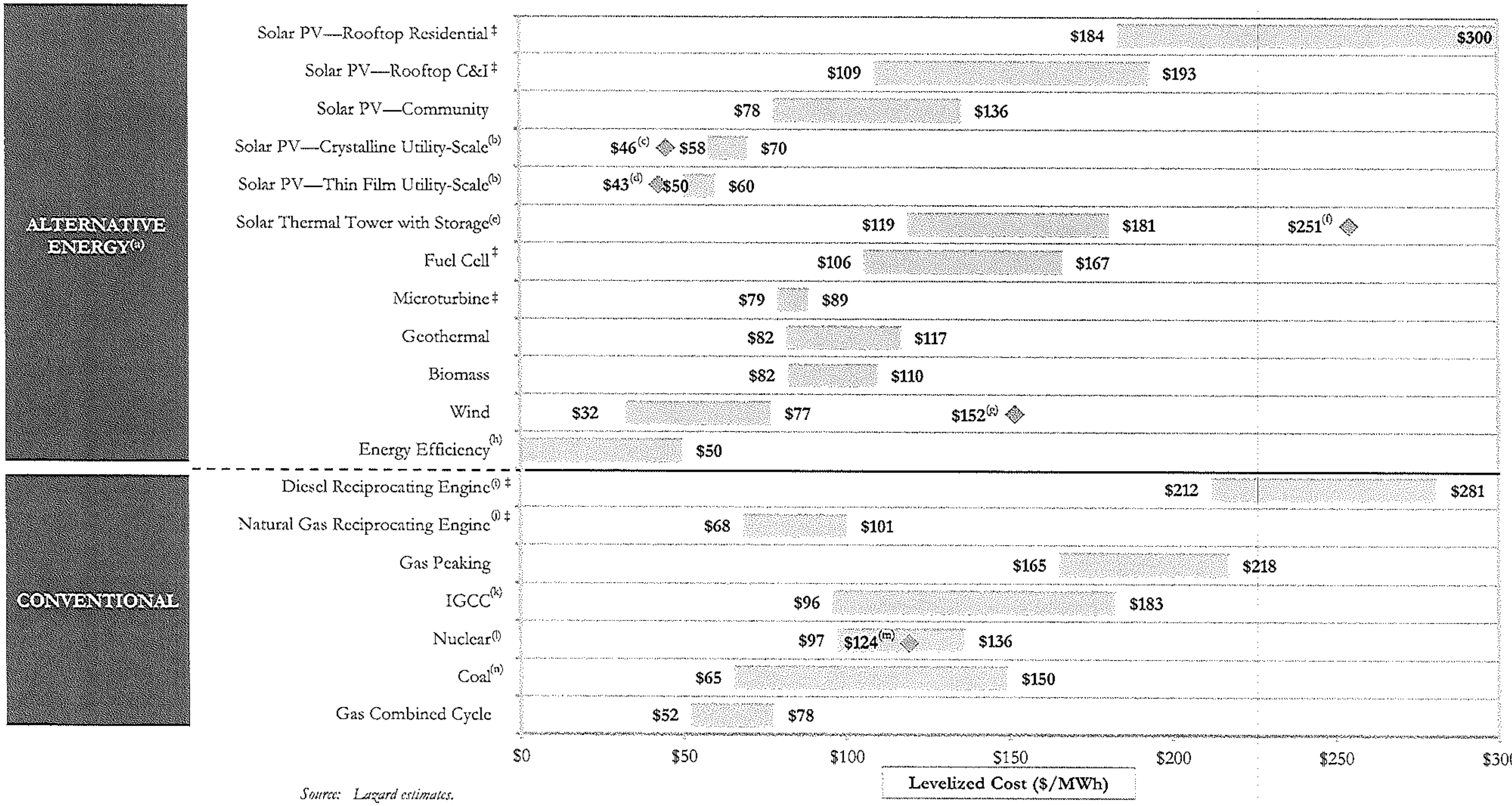
Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or 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 – 9.0 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"

 LAZARD 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 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 both conventional and Alternative Energy generation technologies. Assumes diesel price of ~$2.50 per gallon, Northern Appalachian bituminous coal price of ~$2.00 per MMBtu and a natural gas price of ~$3.50 per MMBtu for all applicable technologies other than Natural Gas Reciprocating Engine, which assumes ~$5.50 per MMBtu. Analysis does not reflect potential impact of evolving regulations/rules promulgated pursuant to the EPA's Clean Power Plan. **See following page for footnotes.**

‡ Denotes distributed generation technology.

Ex. AA-D-22

Unsubsidized Levelized Cost of Energy Comparison (cont'd)

(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 system. High end represents fixed-tilt design. Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(c) Diamond represents estimated implied levelized cost of energy for crystalline utility-scale solar in 2017, assuming $1.35 per watt for a single-axis tracking system.

(d) Diamond represents estimated implied levelized cost of energy for thin film utility-scale solar in 2017, assuming $1.35 per watt for a single-axis tracking system.

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

(f) Diamond represents an illustrative solar thermal facility without storage capability.

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

(h) 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.

(i) Represents distributed diesel generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 10% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 25,000 operating hours.

(j) Represents distributed natural gas generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 30% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 60,000 operating hours.

(k) Does not include cost of transportation and storage.

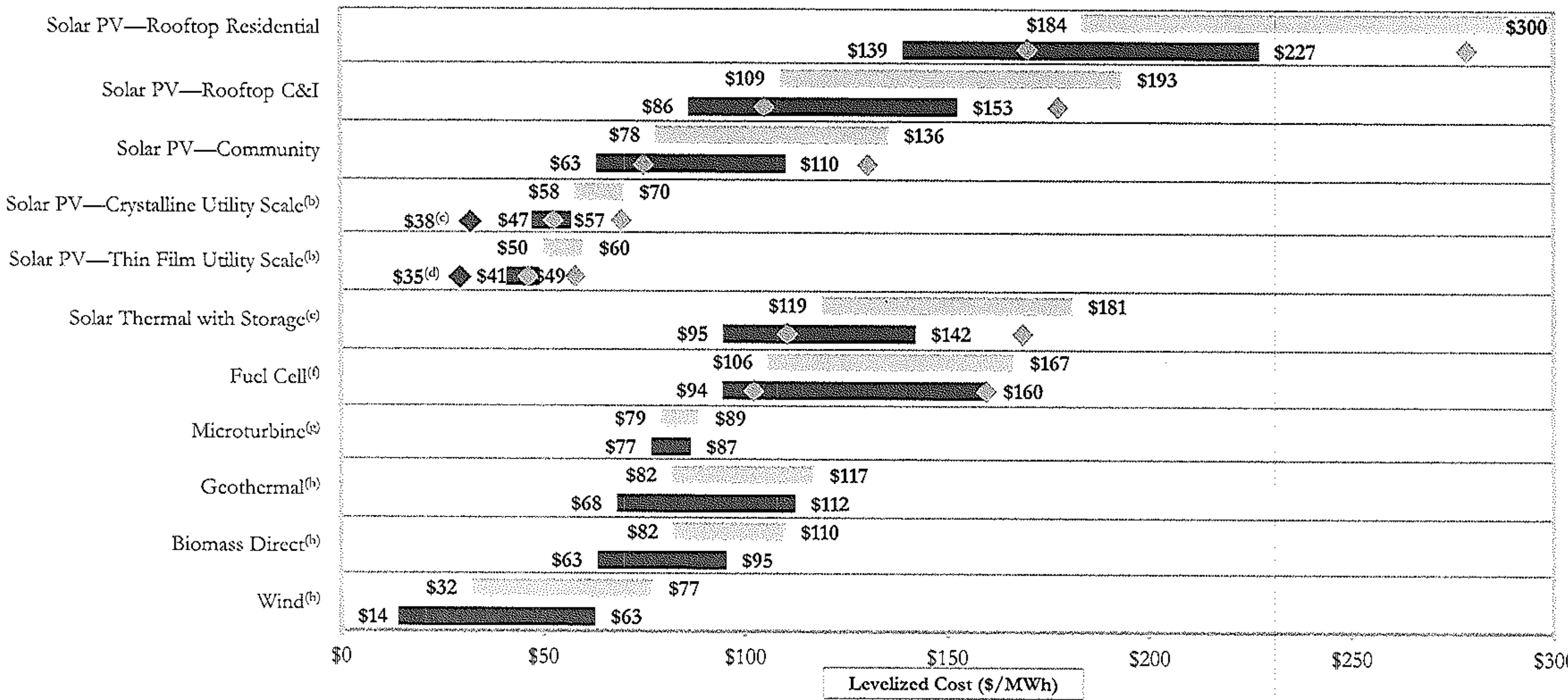
(l) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(m) Represents current estimate of levelized cost of Vogtle project.

(n) Based on advanced supercritical pulverized coal. High end 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[(a)]

Notwithstanding the recent expiration of the Production Tax Credit ("PTC") and planned step down of the Investment Tax Credit ("ITC"), 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)



Source: Lazard estimates.

Note: Despite clear current legislation concerning the expiration of the PTC at the end of 2014 for wind and the planned step down of the ITC from 30% to 10% for applicable technologies/projects put into service after December 31, 2016, the analysis on this page assumes illustrative 10% and 30% ITCs and reinstatement of the PTC.

(a) Unless otherwise noted, the subsidized information reflects an illustrative 30% ITC regardless of time placed into service. Reflects no PTC. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 12.0% cost and 20% common equity at 12.0% cost, unless otherwise noted.

(b) Low end represents a single-axis tracking system. High end represents a fixed-tilt design. Assumes 30 MW installation in high insolation jurisdiction (e.g., Southwest U.S.).

(c) Blue diamond represents estimated implied levelized cost of energy for crystalline utility-scale solar in 2017, assuming $1.35 per watt for a single-axis tracking system.

(d) Blue diamond represents estimated implied levelized cost of energy for thin film utility-scale solar in 2017, assuming $1.35 per watt for a single-axis tracking system.

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

(f) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

(g) Reflects 10% ITC only. Reflects no PTC. Capital structure adjusted for lower ITC; assumes 50% debt at 8.0% interest rate, 20% tax equity at 12.0% cost and 30% common equity at 12.0% cost.

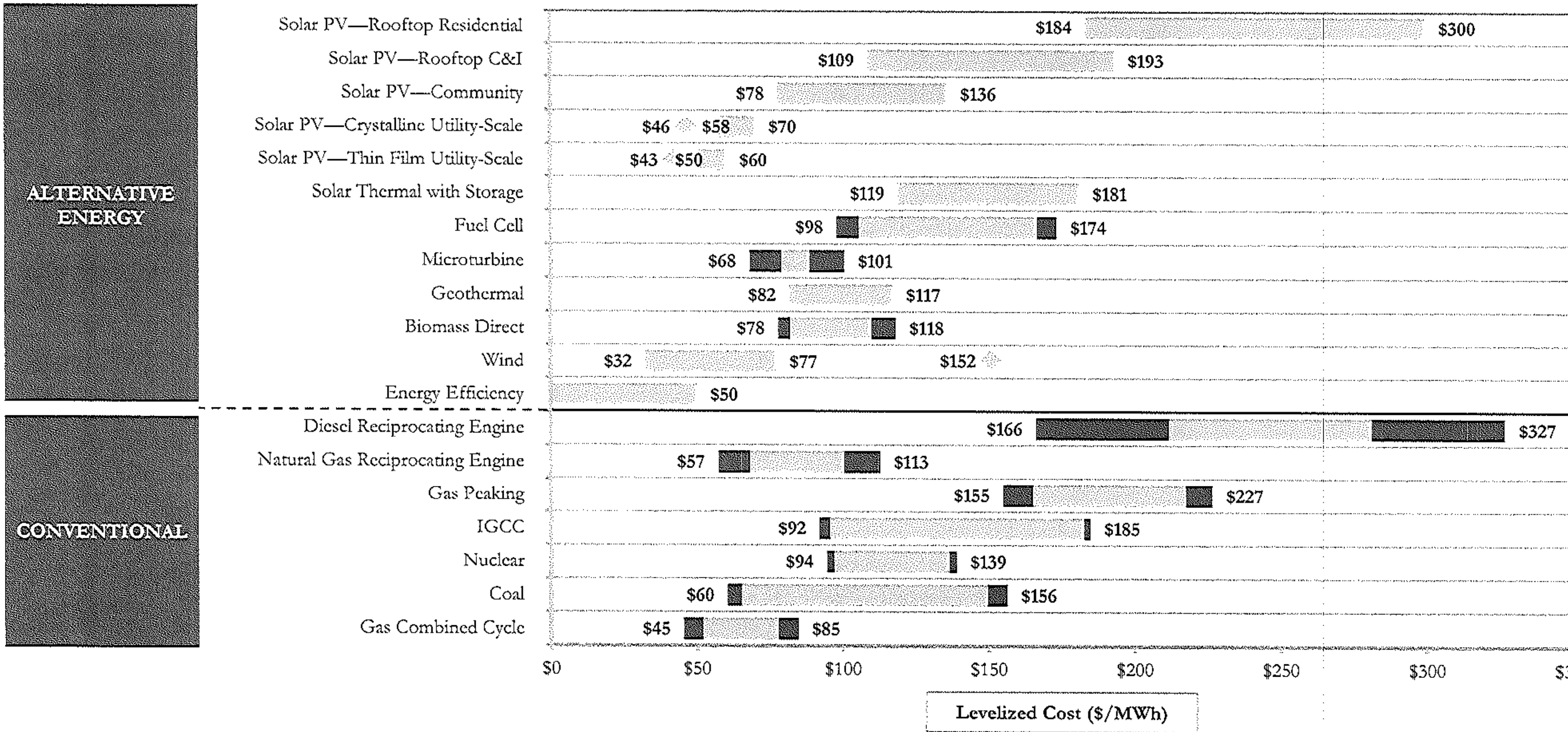
(h) Reflects no ITC. Reflects a $23/MWh illustrative PTC, escalated at ~1.5% annually for a term of 10 years. Due to high capacity factor and, relatedly, high PTC investor appetite, assumes 15% debt at 8.0% interest rate, 70% tax equity at 12.0% cost and 15% common equity at 12.0% cost.

(i) Reflects illustrative 10% ITC. Reflects no PTC. Capital structure adjusted for lower ITC; assumes 50% debt at 8.0% interest rate, 20% tax equity at 12.0% cost and 30% common equity at 12.0% cost.

Ex. AA-D-22

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.

Ex. AA-D-22

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 the Clean Power Plan and related 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 Residential	Solar PV Utility-Scale[c]	Solar Thermal[d] with Storage
Capital Investment/KW of Capacity[a]	$/kW	$3,000	$1,006	$5,385	$1,250	$4,100	$1,750	$10,296
Total Capital Investment	$mm	**$1,800**	**$805**	**$3,339**	**$1,263**	**$9,143**	**$3,255**	**$6,795**
Facility Output	MW	600	800	620	1,010	2,230	1,860	660
Capacity Factor	%	93%	70%	90%	55%	25%	30%	85%
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	$65	$52	$97	$32	$184	$58	$119
Total Cost of Energy Produced	$mm/yr	$320 ②	**$255**	**$474**	**$158**	**$897**	$283 ①	**$582**
CO_2 Equivalent Emissions	Tons/MWh	0.94	0.39	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.58	1.92	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.66	4.58	4.58	4.58	4.58 ③	4.58
vs. Gas		—	—	1.92	1.92	1.92	1.92	1.92
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($65)	$154	($162)	$577	($37) ④	$262
vs. Gas		—	—	$220	($97)	$643	$29	$328
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		—	($25)	$34	($35)	$126	($8) ⑤	$57
vs. Gas		—	—	$115	($50)	$335	$15	$171

Source: Lazard estimates.

Note: Does not reflect Production Tax Credit or Investment Tax Credit. Assumes 2015 dollars, 20 – 40 year economic life, 40% tax rate and five – 40 year tax life. Assumes 2.25% 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 crystalline utility-scale solar with 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:

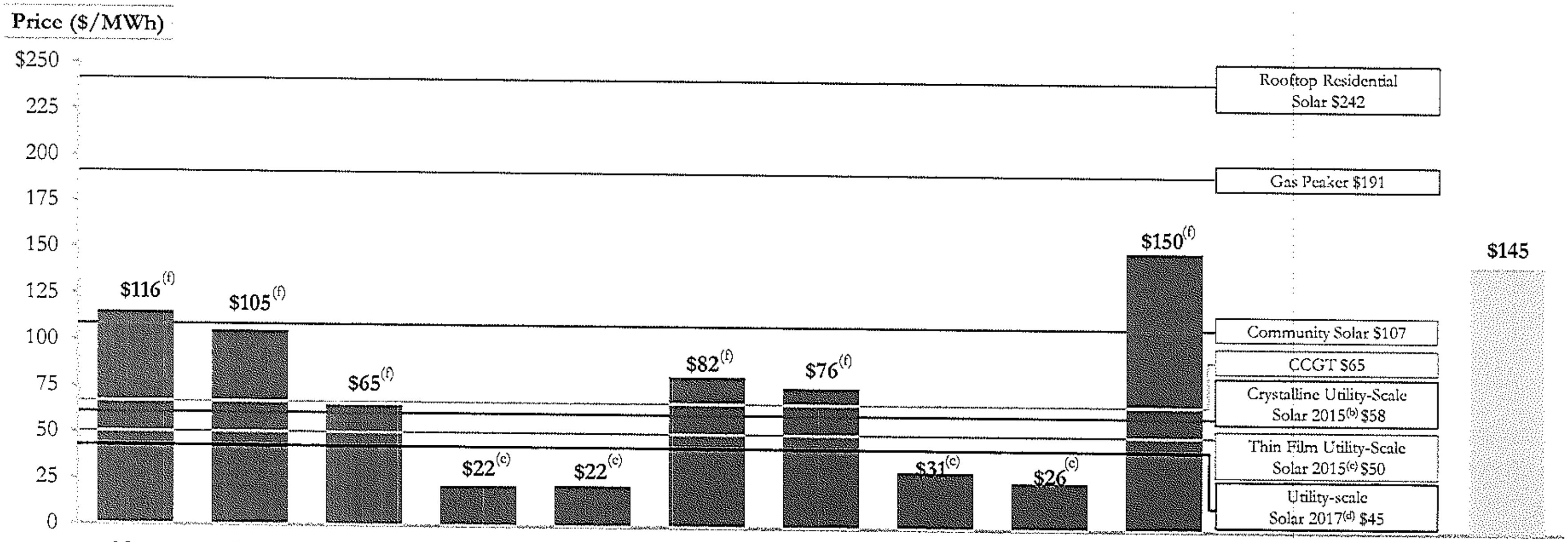
④ Difference in Total Energy Cost vs. Coal = ① – ②
= $283 mm/yr (solar) – $320 mm/yr (coal) = ($37) mm/yr

⑤ Implied Abatement Cost vs. Coal = ④ ÷ ③
= ($37) mm/yr ÷ 4.58 mm Tons/yr = ($8)/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**



Metropolitan Statistical Area	New York	Los Angeles	Chicago	Dallas	Houston	Phila.	D.C.	Miami	Atlanta	Boston	Illustrative U.S. Generation, Transmission and Delivery Charge
Population (mm)	20	13	10	7	6	6	6	6	6	5	
Cumulative % of U.S. population(g)	6%	11%	14%	16%	18%	20%	22%	23%	25%	27%	

Source: *EEI, Ventyx, Lazard estimates.*

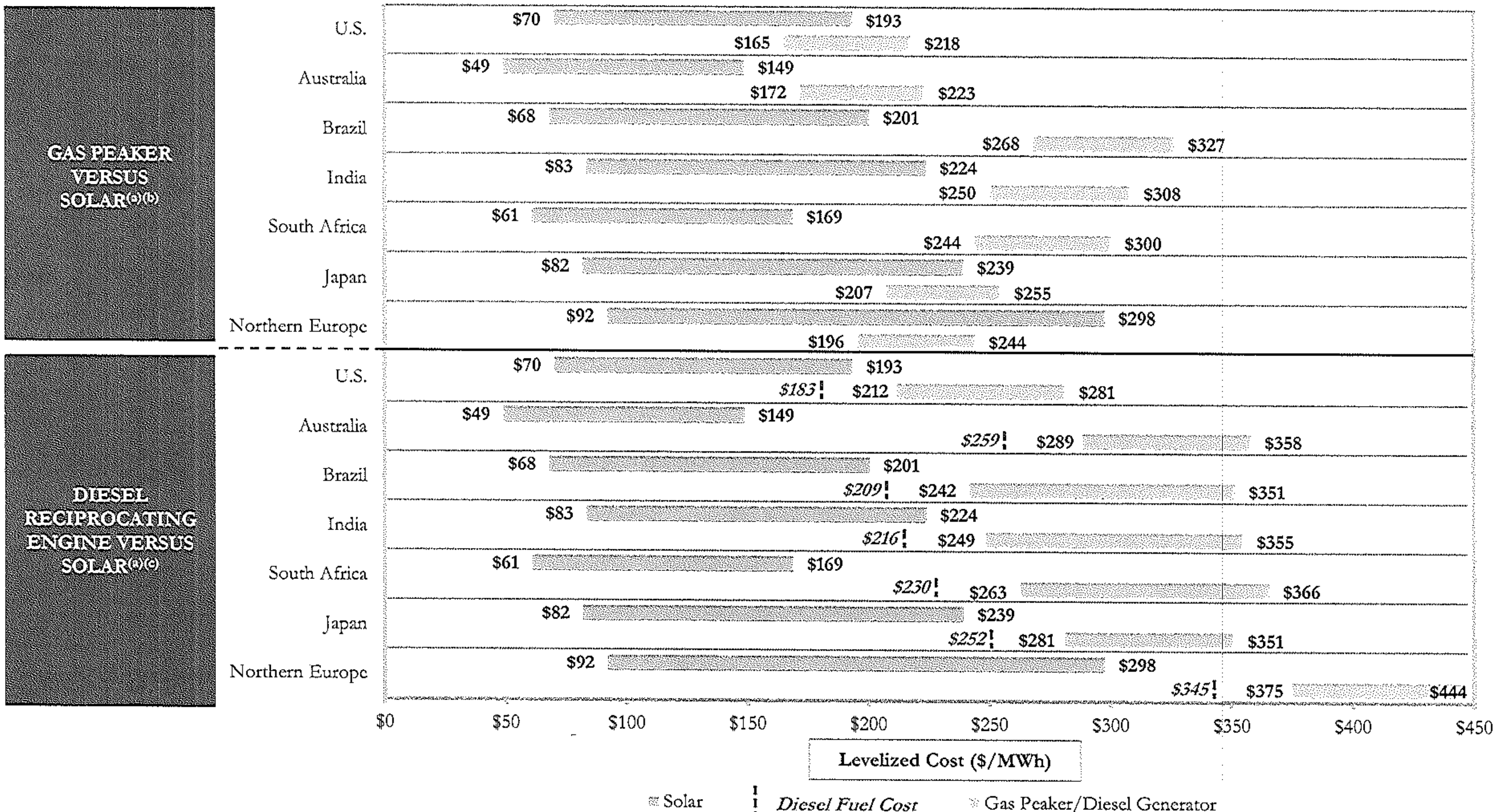
Note: Actual delivered generation prices may be higher, reflecting historical composition of resource portfolio. All technologies represent an average of the high and low levelized cost of energy values unless otherwise noted.

(a) Defined as 10 largest Metropolitan Statistical Areas per the U.S. Census Bureau for a total population of ~85 million.
(b) Represents a crystalline utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.
(c) Represents a thin film utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.
(d) Represents estimated implied levelized cost of energy in 2017 as the mean of crystalline and thin film utility-scale solar single-axis tracking systems, assuming $1.35 per watt for both. Excludes Investment Tax Credit.
(e) Represents average projected hourly 2015 Ventyx power price for applicable jurisdiction.
(f) Represents 1000 kWh generation rate (sourced from EEI) in effect as of January 1, 2015 in applicable jurisdiction.
(g) Represents 2014 census data.

Ex. AA-D-22

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, and Lazard estimates.

(a) Low end assumes crystalline utility-scale solar with a fixed-tilt design. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 26% – 30% for Australia, 26% – 30% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% 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.

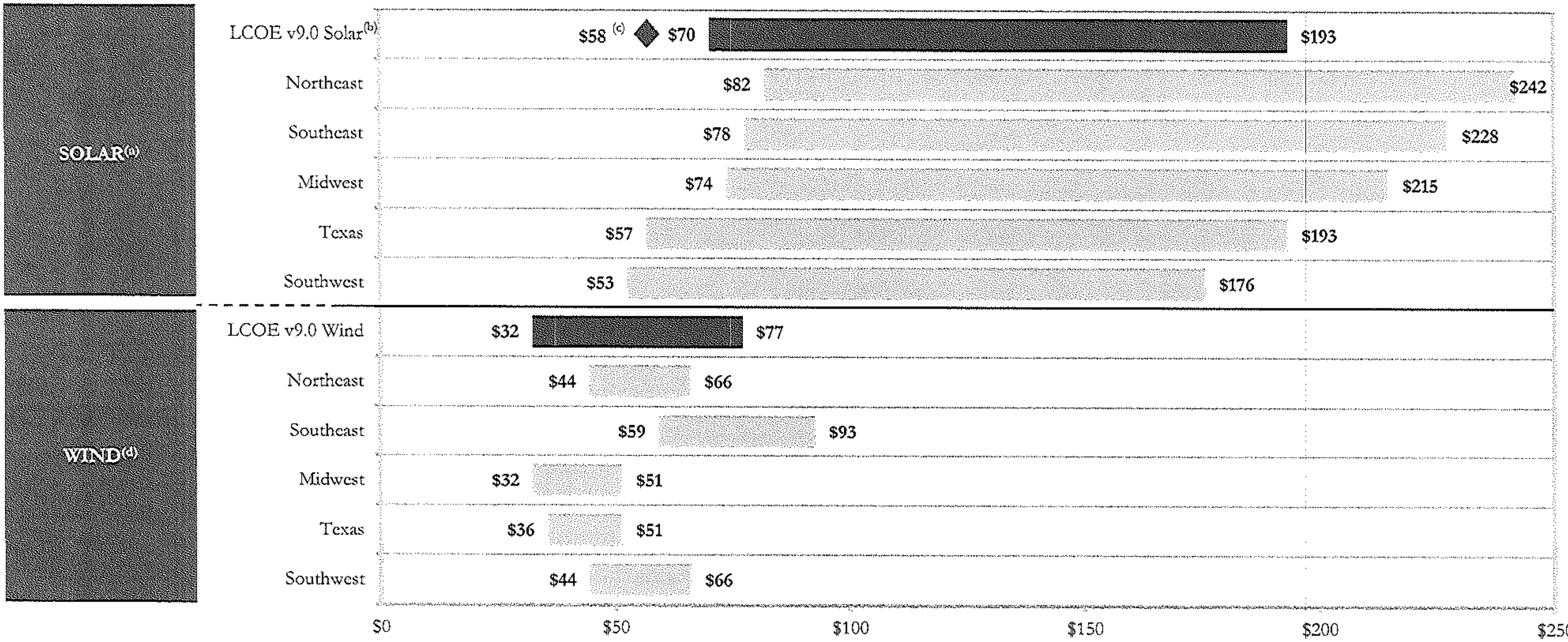
(b) Assumes natural gas prices of $4.00 for Australia, $8.00 for Brazil, $7.00 for India, $7.00 for South Africa, $7.00 for Japan and $6.00 for Northern Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10%.

(c) Diesel assumes high end capacity factor of 10% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization, O&M cost of $30 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 $3.60 for Australia, $2.90 for Brazil, $3.00 for India, $3.20 for South Africa, $3.50 for Japan and $4.80 for Northern Europe (all in U.S.$ per gallon).

Ex. AA-D-22

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.*

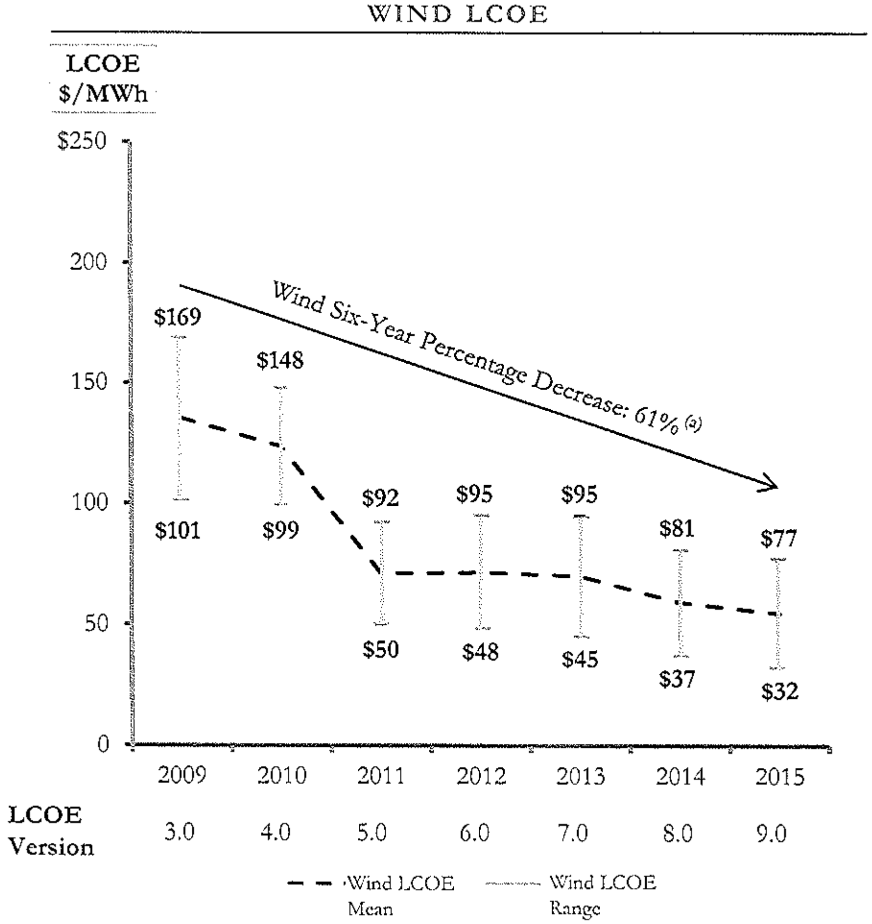
Note: Assumes solar capacity factors of 16% – 18% for the Northeast, 17% – 19% for the Southeast, 18% – 20% for the Midwest, 20% – 26% for Texas and 22% – 28% for the Southwest. Assumes wind capacity factors of 35% – 40% for the Northeast, 25% – 30% for the Southeast, 45% – 55% for the Midwest, 45% – 50% for Texas and 35% – 40% for the Southwest.

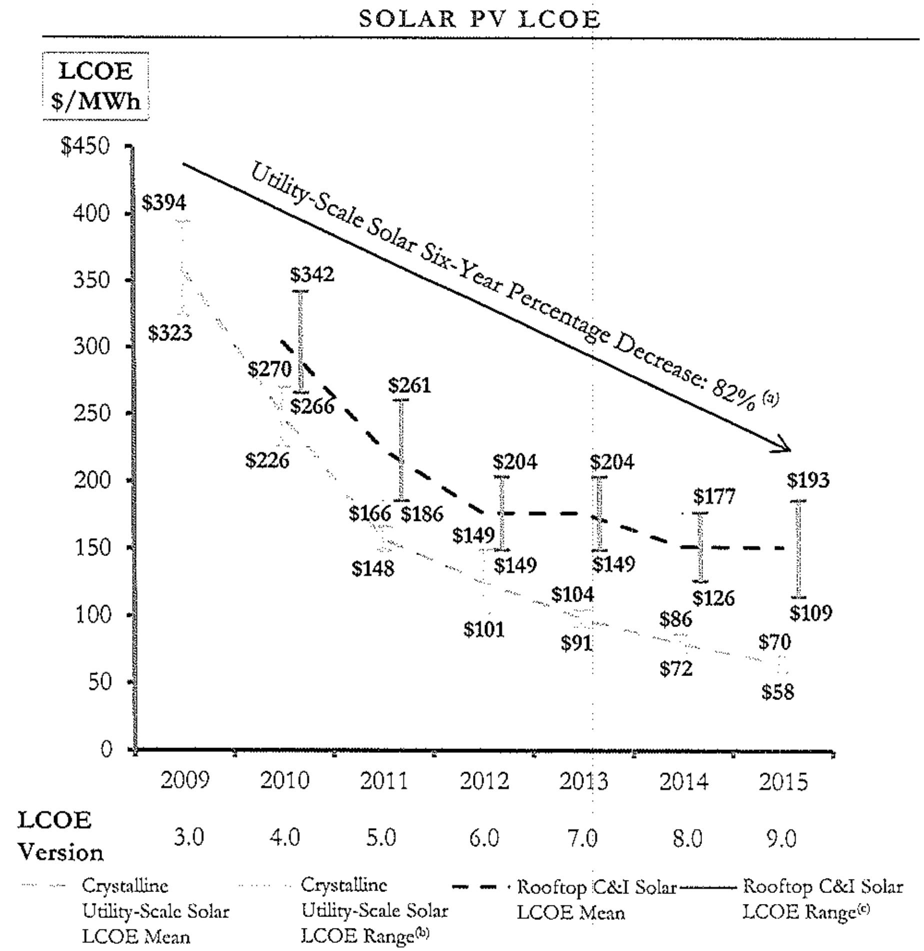
(a) Low end assumes a crystalline utility-scale solar fixed-tilt design, as tracking technologies may not be available in all geographies. High end assumes a rooftop C&I solar system.
(b) Low end assumes a crystalline utility-scale solar fixed-tilt design with a capacity factor of 21%.
(c) Diamond represents a crystalline utility-scale solar single-axis tracking system with a capacity factor of 30%.
(d) Assumes an onshore wind generation plant with capital costs of $1.25 – $1.70 per watt.

Ex. AA-D-22

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

Over the last six 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





Source: Lazard estimates.

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

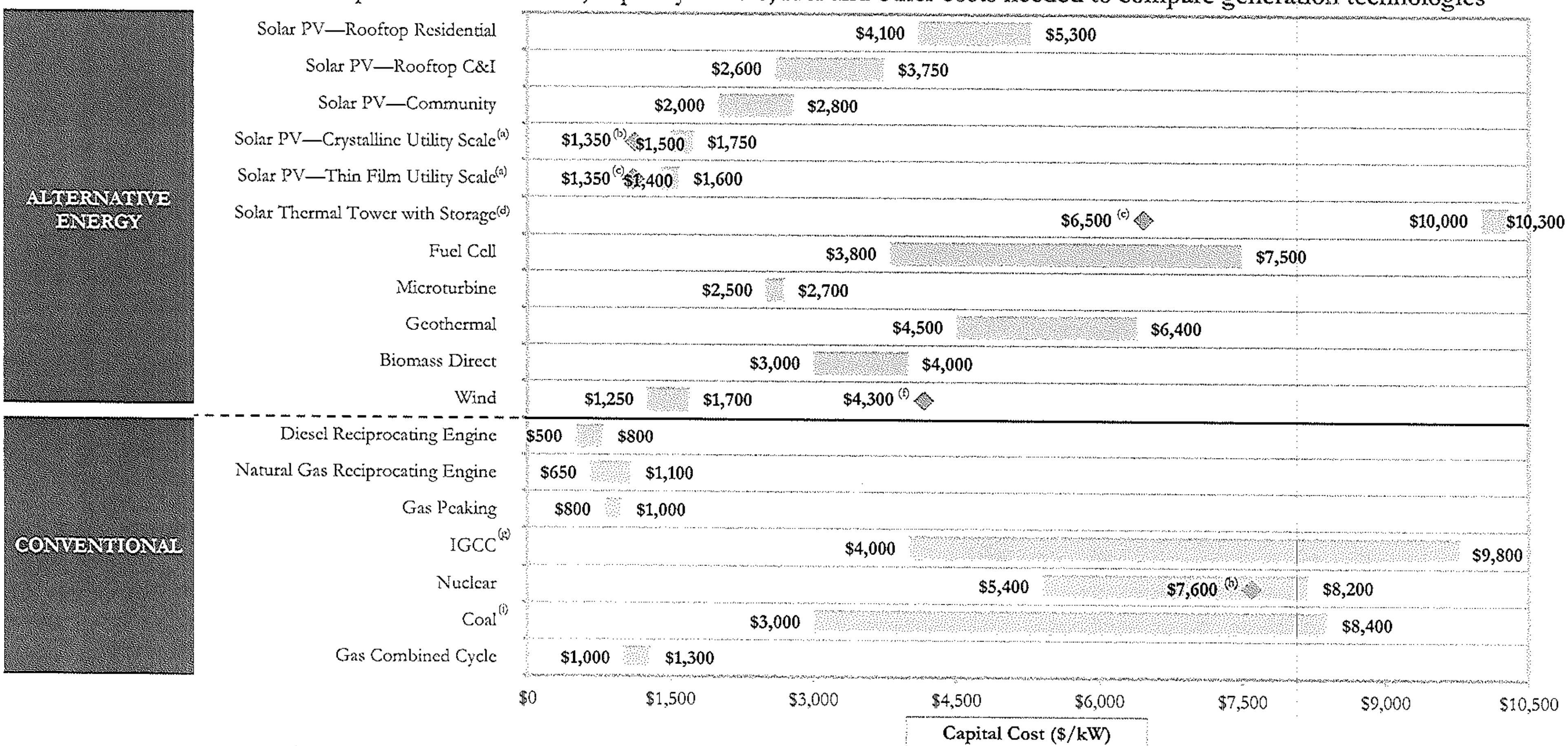
(b) Low end represents crystalline utility-scale solar with single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.), while high end represents crystalline utility-scale solar with fixed-tilt design.

(c) Lazard's LCOE initiated reporting of rooftop C&I solar in 2010.

Ex. AA-D-22

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 capital cost represents the capital cost associated with the low end LCOE of utility-scale solar. Low end capital cost represents the capital cost associated with the high end LCOE of utility-scale solar.
(b) Diamond represents estimated capital costs in 2017, assuming $1.35 per watt for a crystalline utility-scale solar single-axis tracking system.
(c) Diamond represents estimated capital costs in 2017, assuming $1.35 per watt for a thin film utility-scale solar single-axis tracking system.
(d) Low end represents concentrating solar tower with 10-hour storage capability. High end represents concentrating solar tower with 18-hour storage capability.
(e) Diamond represents solar thermal tower capital costs without storage.
(f) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.
(g) High end represents Kemper and it incorporates 90% 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.

Ex. AA-D-22

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

After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Solar PV—Rooftop Residential
Solar PV—Rooftop C&I
Solar PV—Utility Scale[(b)]
Nuclear[(c)]
Coal[(d)]
Gas—Combined Cycle

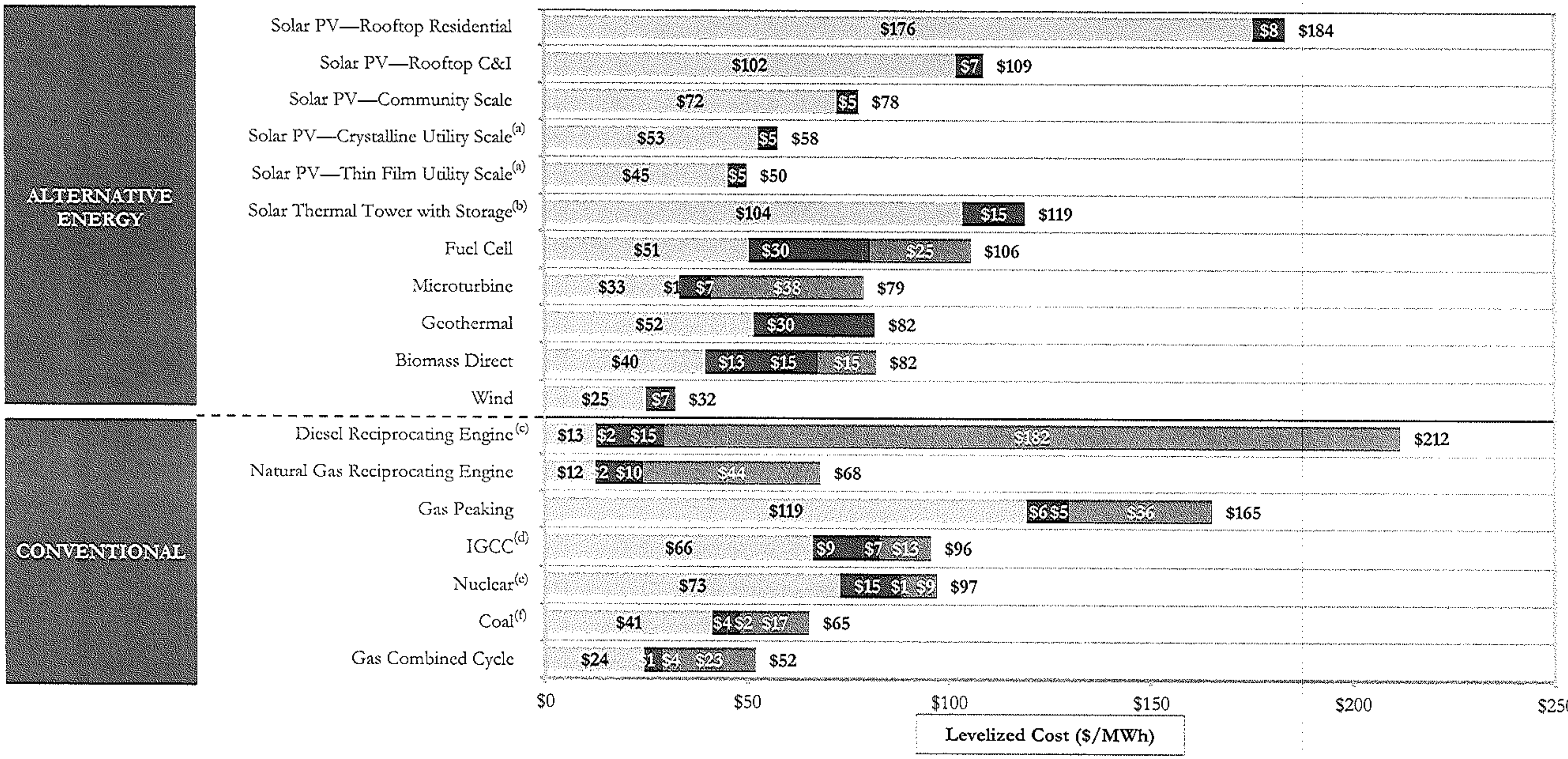
Reflects cost of capital assumption utilized in Lazard's Levelized Cost of Energy analysis

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 thin film utility-scale solar fixed-tilt design with capital costs of $1.40 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.

Ex. AA-D-22

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)

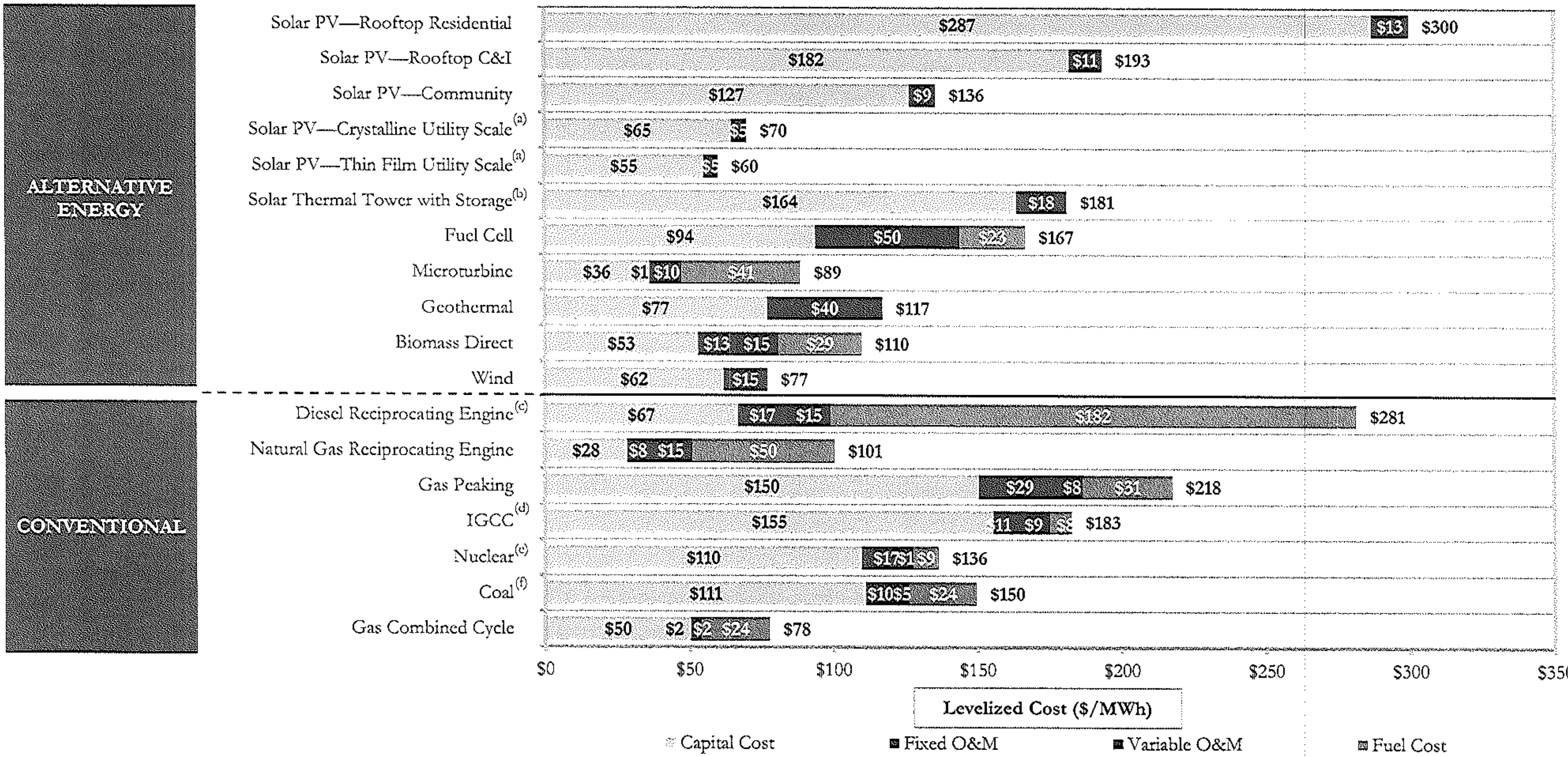


Source: Lazard estimates.

(a) Represents the low end of a utility-scale solar single-axis tracking system.
(b) Represents concentrating solar tower with 18-hour storage capability.
(c) Represents continuous operation.
(d) Does not incorporate carbon capture and compression.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(f) 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) Represents the high end of utility-scale solar fixed-tilt design.
(b) Represents concentrating solar tower with 10-hour storage capability.
(c) Represents intermittent operation.
(d) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(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 transportation and storage.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is in some cases competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) 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	DISTRIBUTED	CENTRALIZED	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	SOLAR PV	$50 – 300[a]	✓	Commercial	✓	✓	Universal[b]	✓	✓		
	SOLAR THERMAL	$119 – 181	✓	Commercial		✓	Varies	✓	✓	✓	
	FUEL CELL	$106 – 167	?	Emerging/ Commercial	✓		Universal				✓
	MICROTURBINE	$79 – 89	?	Emerging/ Commercial	✓		Universal				✓
	GEOTHERMAL	$82 – 117	✓	Mature		✓	Varies				✓
	BIOMASS DIRECT	$82 – 110	✓	Mature		✓	Universal			✓	✓
	ONSHORE WIND	$32 – 77	✓	Mature		✓	Varies	✓			
CONVENTIONAL	DIESEL RECIPROCATING ENGINE	$212 – 281	×	Mature	✓		Universal	✓	✓	✓	✓
	NATURAL GAS RECIPROCATING ENGINE	$68 – 101	×	Mature	✓		Universal	✓	✓	✓	✓
	GAS PEAKING	$165 – 218	×	Mature	✓	✓	Universal		✓	✓	
	IGCC	$96 – 183	×[c]	Emerging[d]		✓	Co-located or rural				✓
	NUCLEAR	$97 – 136	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$65 – 150	×[c]	Mature[d]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$52 – 78	×	Mature	✓	✓	Universal			✓	✓

Source: Lazard estimates.

(a) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.

(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.

Ex. AA-D-22

Levelized Cost of Energy—Key Assumptions

	Units	Solar PV: Rooftop—Residential		Solar PV: Rooftop—C&I		Solar PV: Community		Solar PV: Utility Scale—Crystalline[c]		Solar PV: Utility Scale—Thin Film[c]		Solar Thermal Tower with Storage[d]	
Net Facility Output	MW	0.005		1		1.5		30		30		110	
EPC Cost	$/kW	$4,100	$5,300	$2,600	$3,750	$2,000	$2,800	$1,750	$1,500	$1,600	$1,400	$9,000	$8,750
Capital Cost During Construction	$/kW	—		—		—		—		—		$1,300	$1,250
Other Owner's Costs	$/kW	included		included		included		included		included		included	
Total Capital Cost[a]	$/kW	$4,100	$5,300	$2,600	$3,750	$2,000	$2,800	$1,750	$1,500	$1,600	$1,400	$10,300	$10,000
Fixed O&M	$/kW-yr	$17.50	$22.50	$15.00	$20.00	$12.00	$16.00	$13.00	$10.00	$13.00	$10.00	$115.00	$80.00
Variable O&M	$/MWh	—		—		—		—		—		—	
Heat Rate	Btu/kWh	—		—		—		—		—		—	
Capacity Factor	%	25%	20%	25%	20%	25%	20%	30%	21%	32%	23%	85%	52%
Fuel Price	$/MMBtu	—		—		—		—		—		—	
Construction Time	Months	3		3		6		9		9		36	
Facility Life	Years	20		25		30		30		30		35	
CO_2 Emissions	lb/MMBtu	—		—		—		—		—		—	
Levelized Cost of Energy[b]	$/MWh	$184	$300	$109	$193	$78	$136	$58	$70	$50	$60	$119	$181

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 – 9.0 present LCOE on an unsubsidized basis.

(c) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(d) Left column represents concentrating solar tower with 18-hour storage capability. Right column represents concentrating solar tower with 10-hour storage capability.

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

	Units	Fuel Cell	Microturbine	Geothermal	Biomass Direct	Wind—On Shore	Wind—Off Shore
Net Facility Output	MW	2.4	1 - 0.25	20 - 50	35	100	210
EPC Cost	$/kW	$3,000 - $7,500	$2,500 - $2,700	$3,900 - $5,600	$2,600 - $3,500	$950 - $1,100	$2,500 - $4,600
Capital Cost During Construction	$/kW	—	—	$600 - $800	$400 - $500	—	—
Other Owner's Costs	$/kW	$800 - $0	included	included	included	$300 - $600	$600 - $900
Total Capital Cost[(a)]	$/kW	$3,800 - $7,500	$2,500 - $2,700	$4,500 - $6,400	$3,000 - $4,000	$1,250 - $1,700	$3,100 - $5,500
Fixed O&M	$/kW-yr	—	$6.85 - $9.12	—	$95.00	$35.00 - $40.00	$60.00 - $100.00
Variable O&M	$/MWh	$30 - $50	$7.00 - $10.00	$30.00 - $40.00	$15.00	—	$13.00 - $18.00
Heat Rate	Btu/kWh	7,260 - 6,600	11,000 - 12,000	—	14,500	—	—
Capacity Factor	%	95%	95%	90% - 85%	85%	55% - 30%	45% - 40%
Fuel Price	$/MMBtu	$3.45	$3.45	—	$1.00 - $2.00	—	—
Construction Time	Months	3	3	36	36	12	12
Facility Life	Years	20	20	25	25	20	20
CO_2 Emissions	lb/MMBtu	0 - 117	—	—	—	—	—
Levelized Cost of Energy[(b)]	$/MWh	$106 - $167	$79 - $89	$82 - $117	$82 - $110	$32 - $77	$105 - $198

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 – 9.0 present LCOE on an unsubsidized basis.

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

	Units	Diesel Reciprocating Engine[c]	Natural Gas Reciprocating Engine	Gas Peaking	IGCC[d]	Nuclear[e]	Coal[f]	Gas Combined Cycle
Net Facility Output	MW	2	2	216 - 103	580	1,100	600	550
EPC Cost	$/kW	$500 - $800	$650 - $1,100	$600 - $700	$3,300 - $7,800	$3,800 - $5,200	$2,000 - $6,100	$700 - $1,000
Capital Cost During Construction	$/kW	—	—	—	$700 - $2,000	$1,000 - $1,500	$500 - $1,600	$100 - $100
Other Owner's Costs	$/kW	included	included	$200 - $300	$0 - $0	$600 - $1,500	$500 - $700	$200 - $200
Total Capital Cost[a]	$/kW	$500 - $800	$650 - $1,100	$800 - $1,000	$4,000 - $9,800	$5,400 - $8,200	$3,000 - $8,400	$1,000 - $1,300
Fixed O&M	$/kW-yr	$15.00	$15.00 - $20.00	$5.00 - $25.00	$62.25 - $73.00	$135.00	$40.00 - $80.00	$6.20 - $5.50
Variable O&M	$/MWh	$15.00	$10.00 - $15.00	$4.70 - $7.50	$7.00 - $8.50	$0.50 - $0.75	$2.00 - $5.00	$3.50 - $2.00
Heat Rate	Btu/kWh	10,000	8,000 - 9,000	10,300 - 9,000	8,800 - 11,700	10,450	8,750 - 12,000	6,700 - 6,900
Capacity Factor	%	95% - 10%	95% - 30%	10%	75%	90%	93%	70% - 40%
Fuel Price	$/MMBtu	$18.23	$5.50	$3.45	$1.46 - $0.65	$0.85	$1.96	$3.45
Construction Time	Months	3	3	25	57 - 63	69	60 - 66	36
Facility Life	Years	20	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 - 117	117	117	169	—	211	117
Levelized Cost of Energy[b]	$/MWh	$212 - $281	$68 - $101	$165 - $218	$96 - $183	$97 - $136	$65 - $150	$52 - $78

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 – 9.0 present LCOE on an unsubsidized basis.

(c) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of ~$2.50 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, etc.) 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 other important metrics on the levelized cost of energy. These inputs were originally 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.).

Ex. AA-D-24

NOVEMBER 2018

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 12.0

LAZARD

Introduction

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

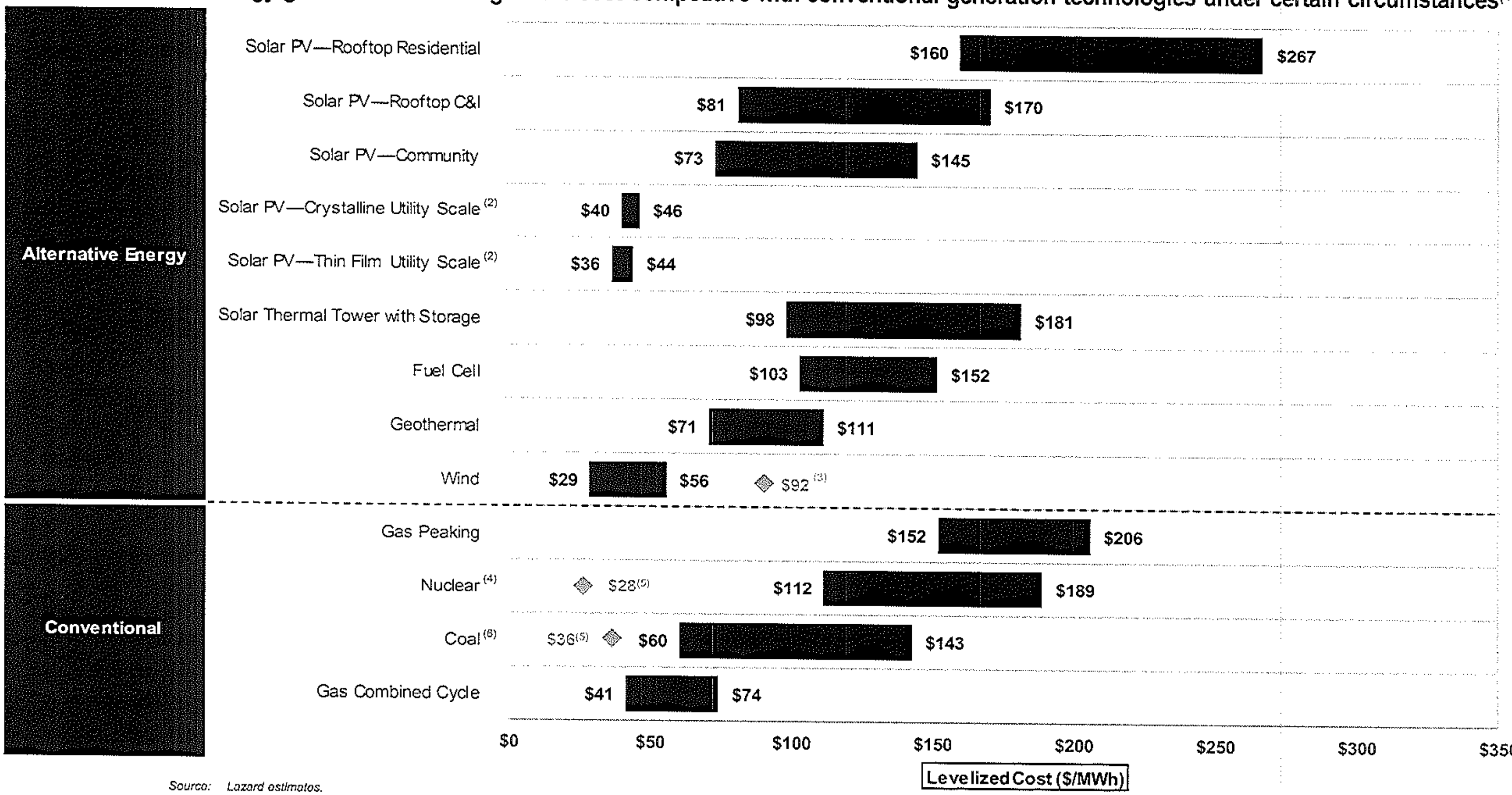
- Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel prices and costs of capital
- Illustration of how the LCOE of wind and utility-scale solar compare to the marginal cost of selected conventional generation technologies
- Historical LCOE comparison of various utility-scale generation technologies
- Illustration of the historical LCOE declines for wind and utility-scale solar technologies
- Illustration of how the LCOE of utility-scale solar compares to the LCOE of gas peaking and how the LCOE of wind compares to the LCOE of gas combined cycle generation
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Decomposition of the LCOE for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense and fuel cost, as relevant
- A methodological overview of Lazard's approach to our LCOE analysis
- Considerations regarding the usage characteristics and applicability of various generation technologies
- An illustrative comparison of the cost of carbon abatement of various Alternative Energy technologies relative to conventional generation
- Summary assumptions for Lazard's LCOE analysis
- Summary of Lazard's approach to comparing the LCOE 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 analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed 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, airborne pollutants, greenhouse gases, etc.)

Ex. AA-D-24

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances(1)



Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities.

(1) Such observation does not take into account other factors that would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This 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, airborne pollutants, greenhouse gases, etc.).

(2) Unless otherwise indicated herein, the low end represents a single-axis tracking system and the high end represents a fixed-tilt design.

(3) Represents the estimated implied midpoint of the LCOE of offshore wind, assuming a capital cost range of approximately $2.25 – $3.80 per watt.

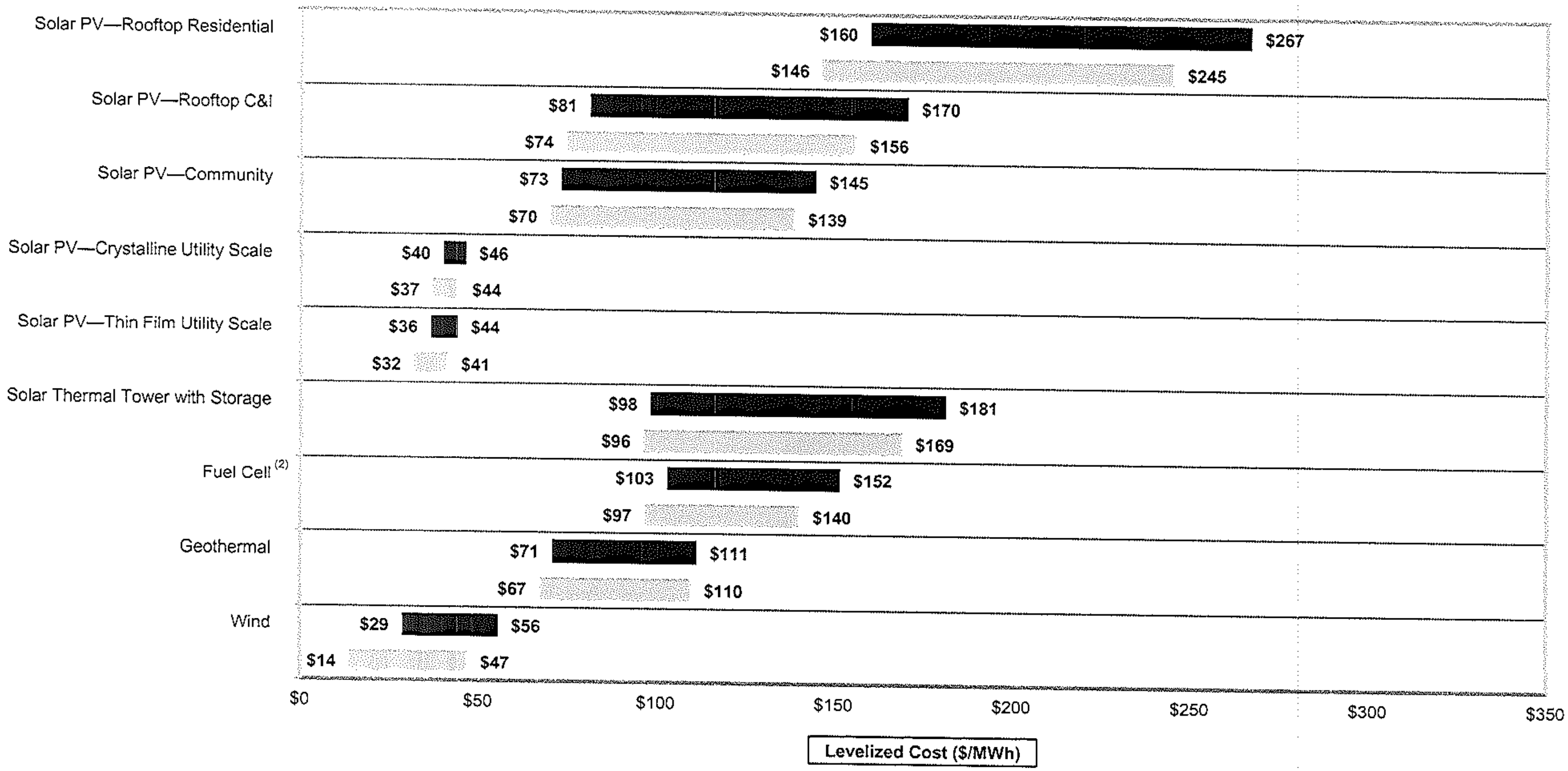
(4) Unless otherwise indicated, the analysis herein does not reflect decommissioning costs or the potential economic impacts of federal loan guarantees or other subsidies.

(5) Represents the midpoint of the marginal cost of operating fully depreciated coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to the decommissioning and site restoration costs. Inputs are derived from a benchmark of operating, fully depreciated coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research. Please see page titled "Levelized Cost of Energy Comparison—Alternative Energy versus Marginal Cost of Selected Existing Conventional Generation" for additional details.

(6) Unless otherwise indicated, the analysis herein reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies(1)

Given the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") in December 2015 and resulting subsidy visibility, U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies



Source: *Lazard estimates.*

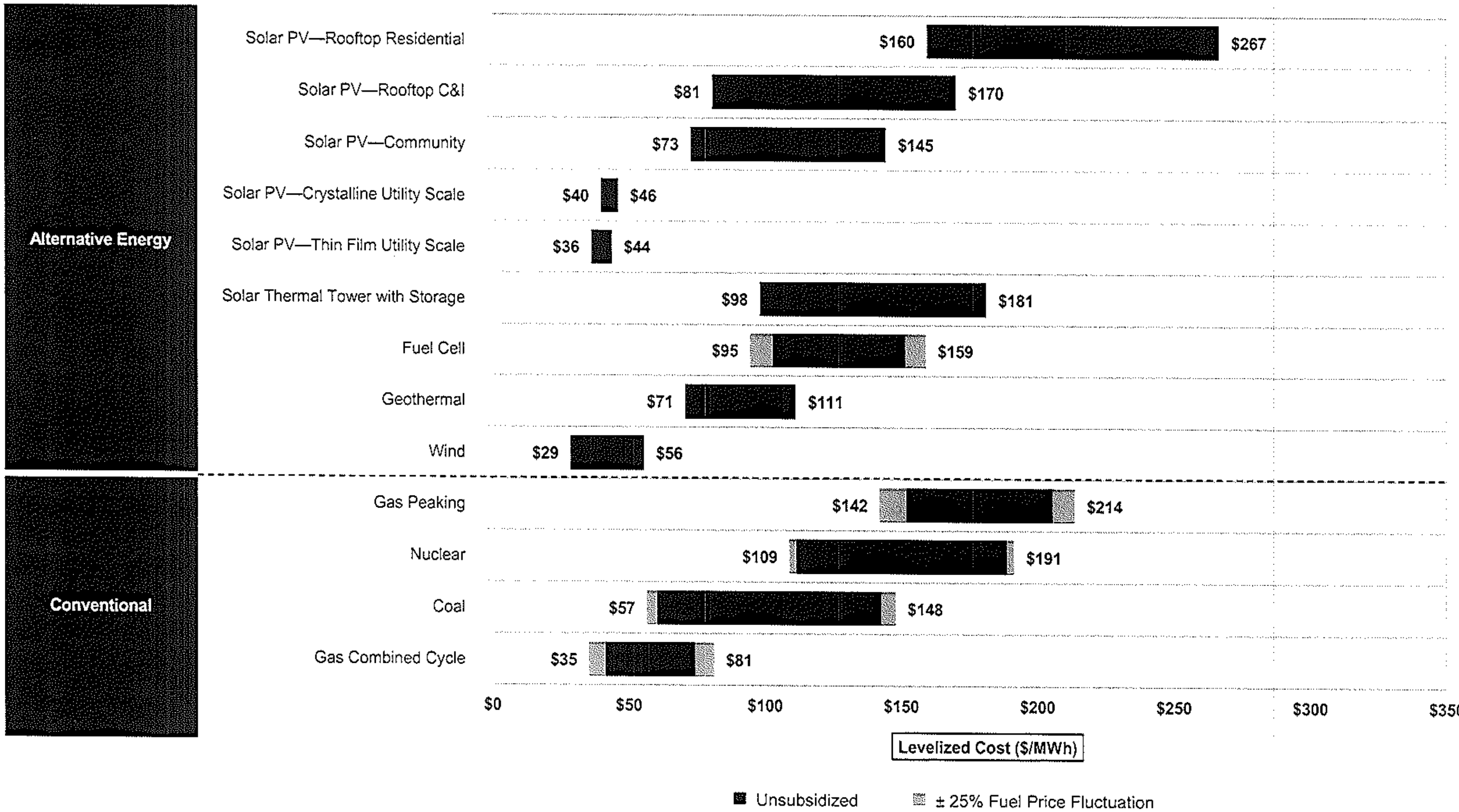
Note: The sensitivity analysis presented on this page also includes sensitivities related to the U.S. Tax Cuts and Jobs Act ("TCJA") of 2017. The TCJA contains several provisions that impact the LCOE of various generation technologies (e.g., a reduced federal corporate income tax rate, an ability to elect immediate bonus depreciation, limitations on the deductibility of interest expense and restrictions on the utilization of past net operating losses). On balance, the TCJA reduced the LCOE of conventional generation technologies and marginally increased the LCOE for Alternative Energy technologies.

(1) The sensitivity analysis presented on this page assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, tax equity and debt.

(2) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the LCOE of 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)

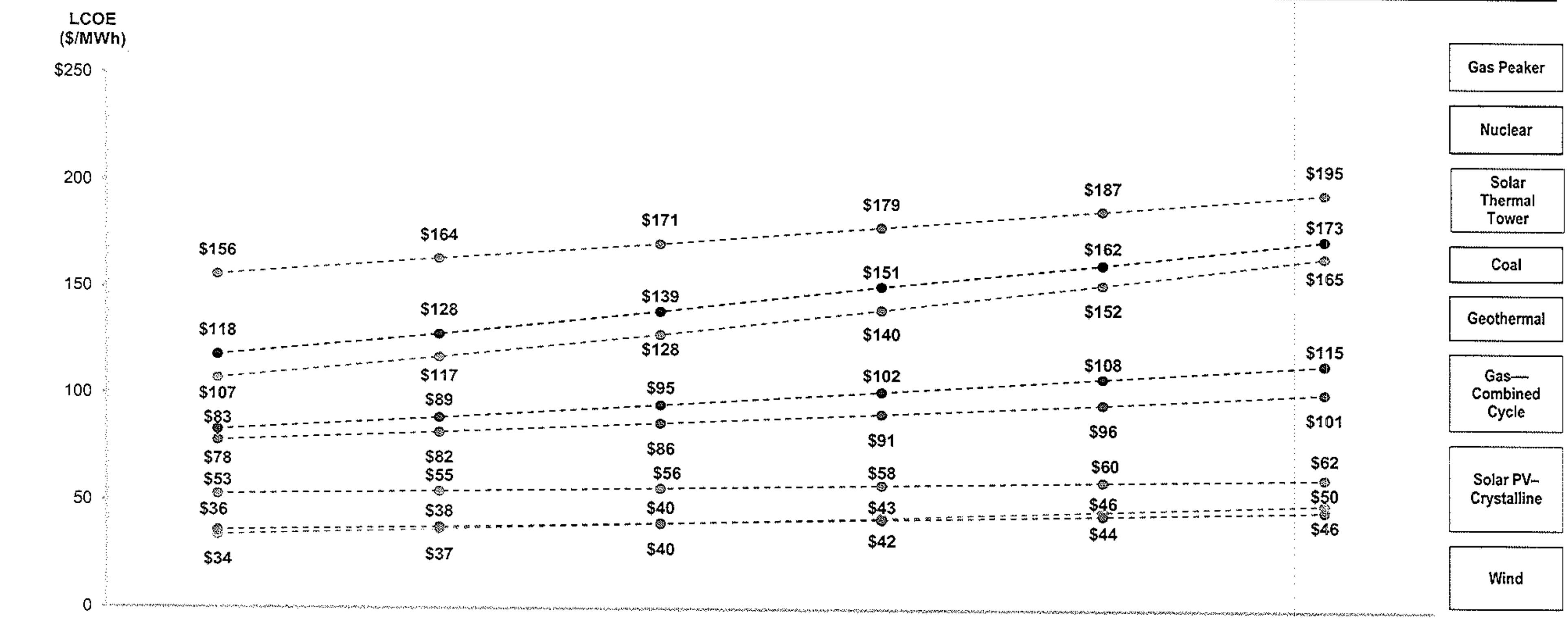


Source: Lazard estimates.

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration for utility-scale generation technologies is the impact of the availability and cost of capital[1] on LCOE values; 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

Midpoint of Unsubsidized LCOE[2]

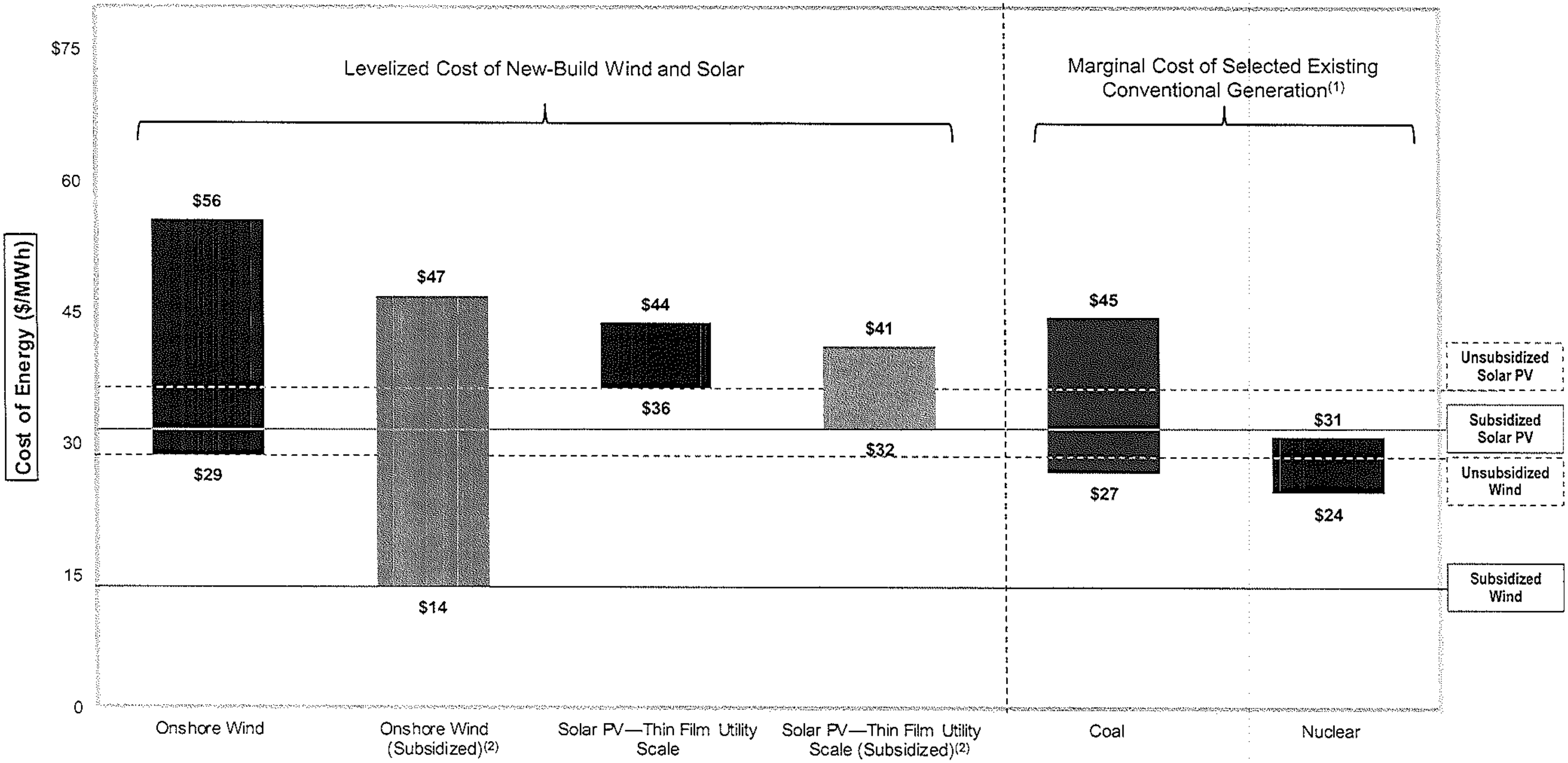


After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Source: *Lazard estimates.*
Note: Analysis assumes 60% debt and 40% equity.
(1) Cost of capital as used herein indicates the cost of capital for the asset/plant and not the cost of capital of a particular investor/owner.
(2) Reflects the average of the high and low LCOE for each respective cost of capital assumption.

Levelized Cost of Energy Comparison—Alternative Energy versus Marginal Cost of Selected Existing Conventional Generation

Certain Alternative Energy generation technologies, which became cost-competitive with conventional generation technologies several years ago, are, in some scenarios, approaching an LCOE that is at or below the marginal cost of existing conventional generation technologies



Source: Lazard estimates.

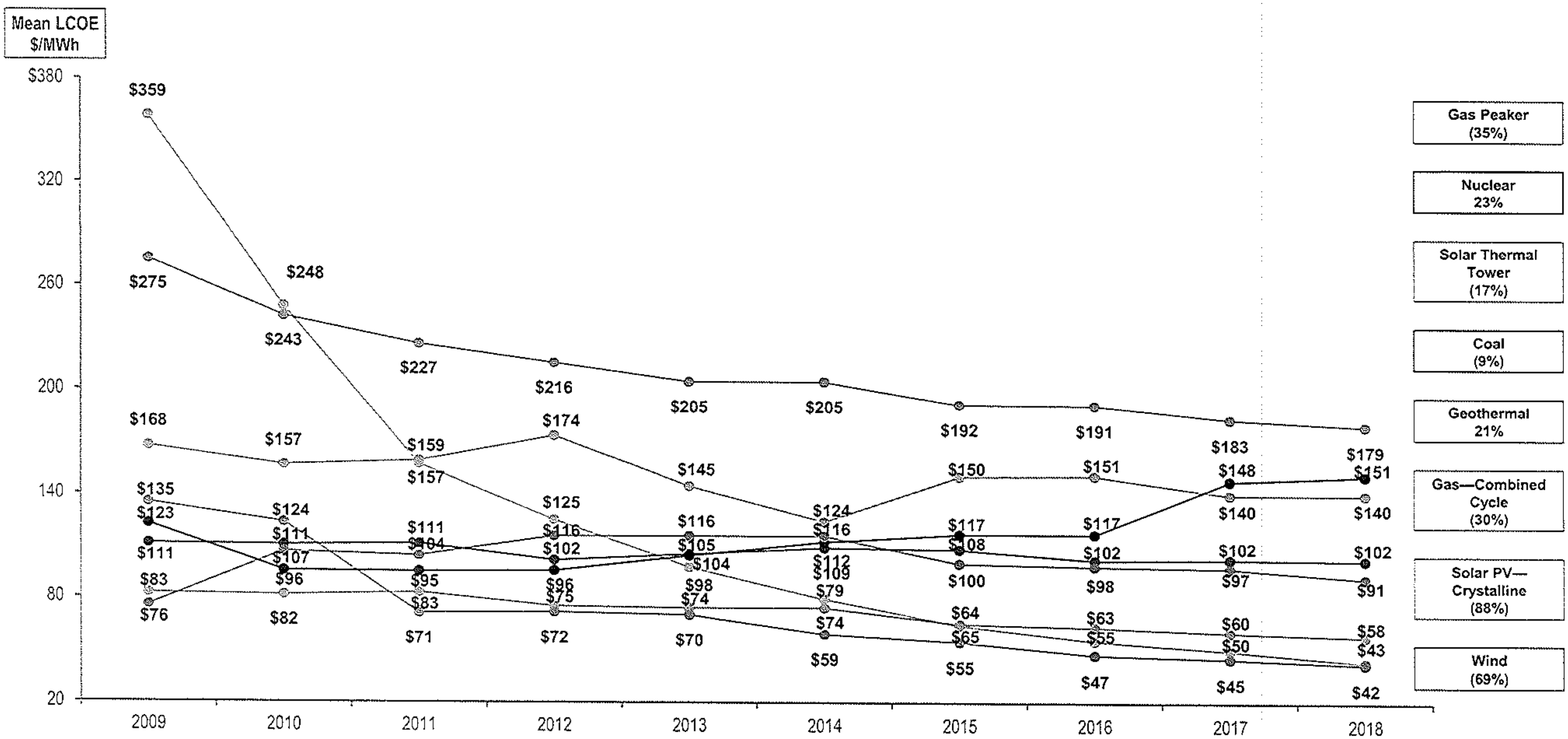
(1) Represents the marginal cost of operating, fully depreciated coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to the decommissioning and site restoration costs. Inputs are derived from a benchmark of operating, fully depreciated coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research.

(2) The subsidized analysis includes sensitivities related to the TCJA and U.S. federal tax subsidies. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

Levelized Cost of Energy Comparison—Historical Utility-Scale Generation Comparison

Lazard's unsubsidized LCOE analysis indicates significant historical cost declines for utility-scale Alternative Energy generation technologies driven by, among other factors, decreasing supply chain costs, improving technologies and increased competition

Selected Historical Mean Unsubsidized LCOE Values[1]



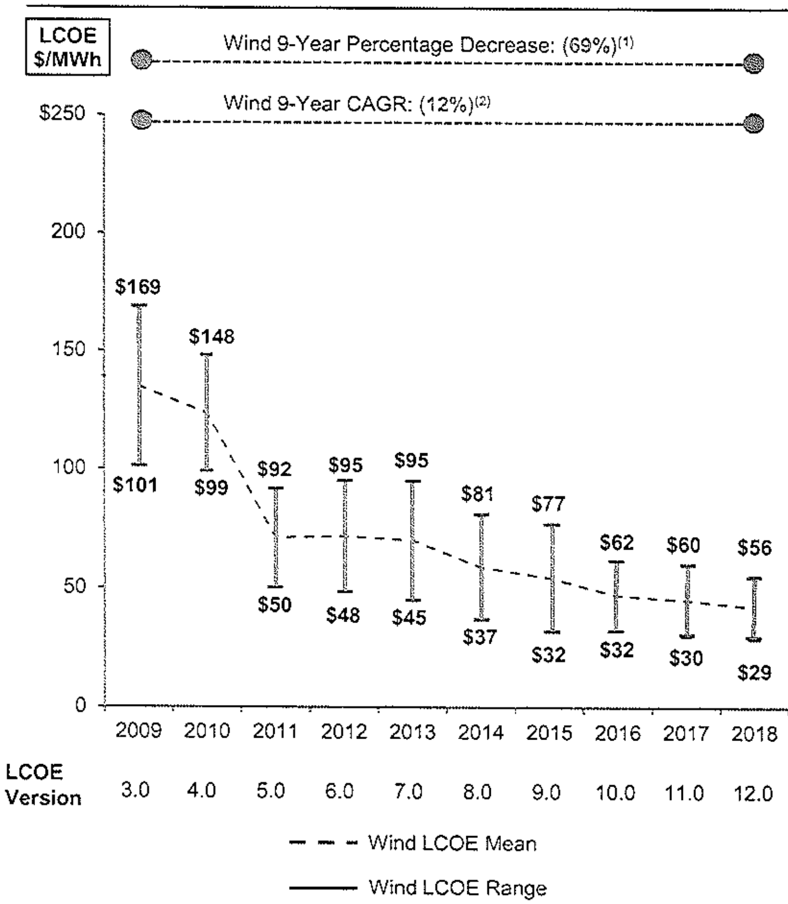
Source: Lazard estimates.

(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE—Version 3.0.

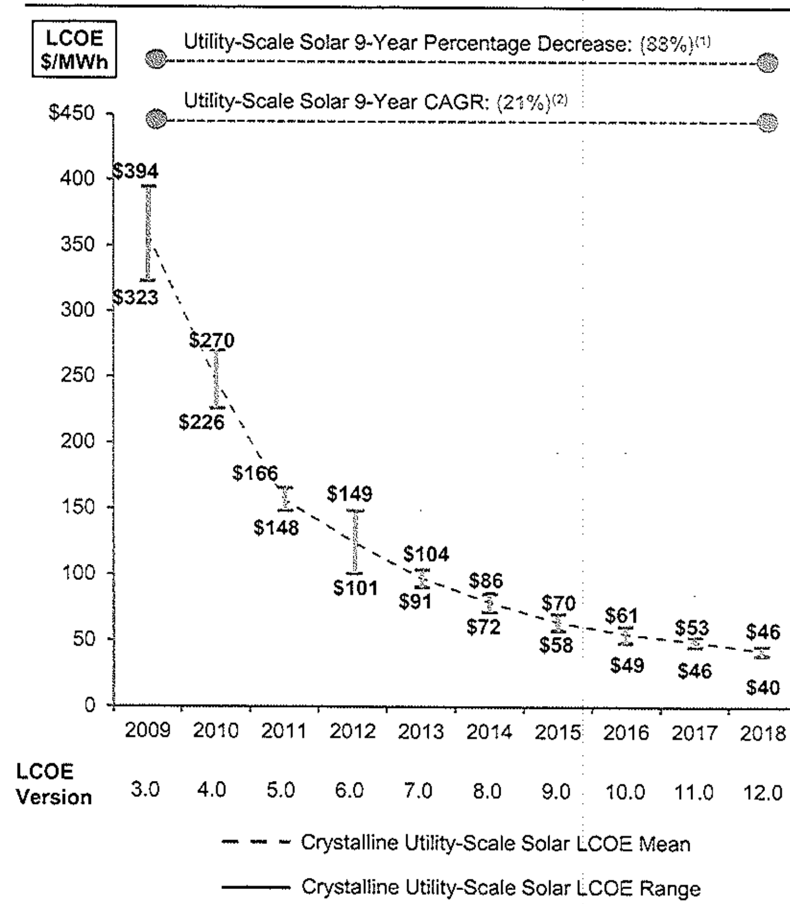
Levelized Cost of Energy Comparison—Historical Alternative Energy LCOE Declines

In light of material declines in the pricing of system components (e.g., panels, inverters, turbines, etc.) and improvements in efficiency, among other factors, wind and utility-scale solar PV have seen dramatic historical LCOE declines; however, over the past several years the rate of such LCOE declines have started to flatten

Unsubsidized Wind LCOE



Unsubsidized Solar PV LCOE

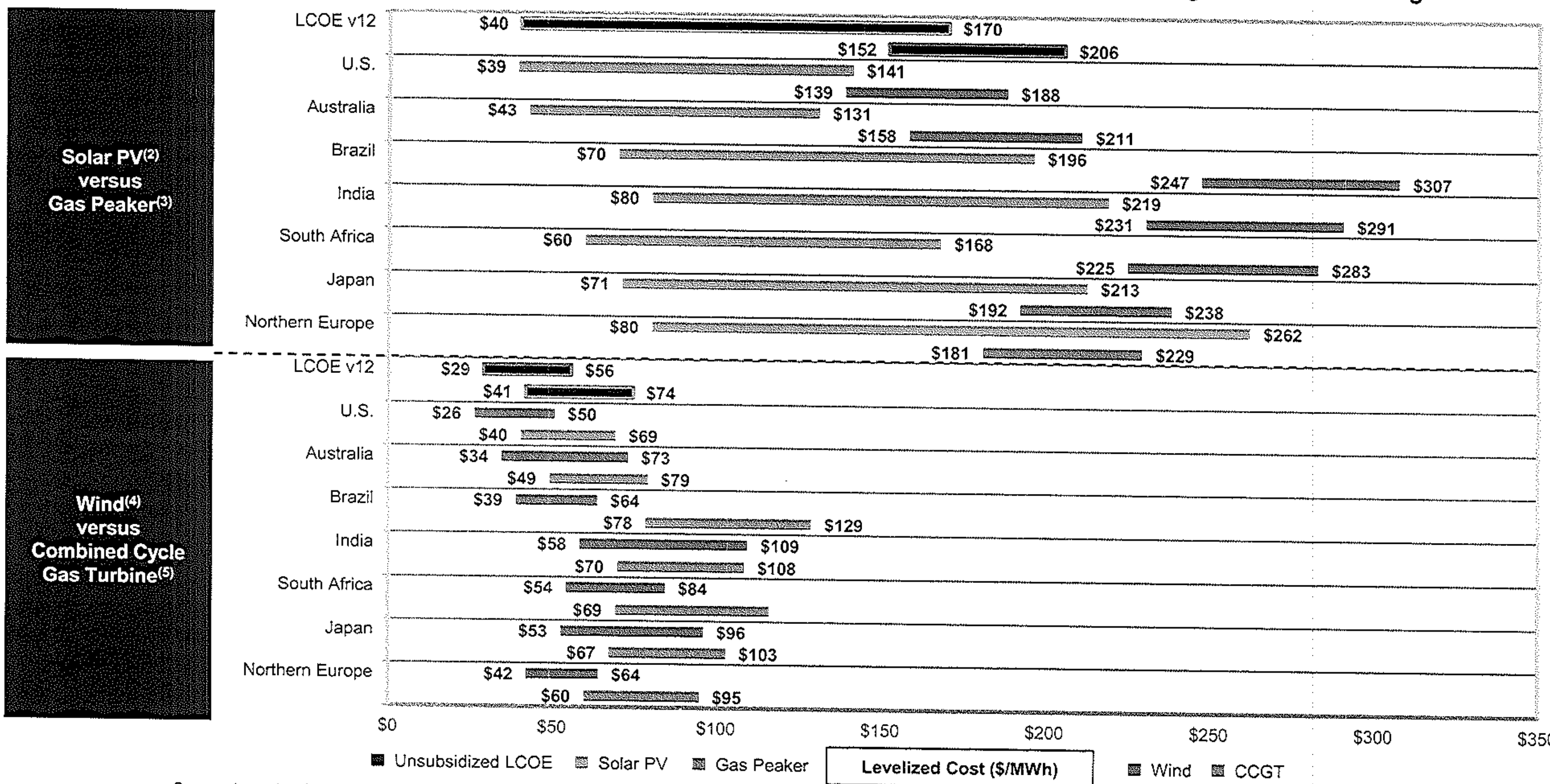


Source: *Lazard estimates.*
(1) Represents the average percentage decrease of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Ex. AA-D-24

Solar PV versus Peaking and Wind versus CCGT—Global Markets(1)

Solar PV and wind have become an increasingly attractive resource relative to conventional generation technologies with similar generation profiles; without storage, however, these resources lack the dispatch characteristics of such conventional generation technologies



Source: Lazard estimates.

(1) Equity IRRs are assumed to be 10% for the U.S., 12% for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa. Cost of debt is assumed to be 6% for the U.S., 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(2) Low end assumes crystalline utility-scale solar with a single-axis tracker. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 21% – 28% for the U.S., 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Northern Europe.

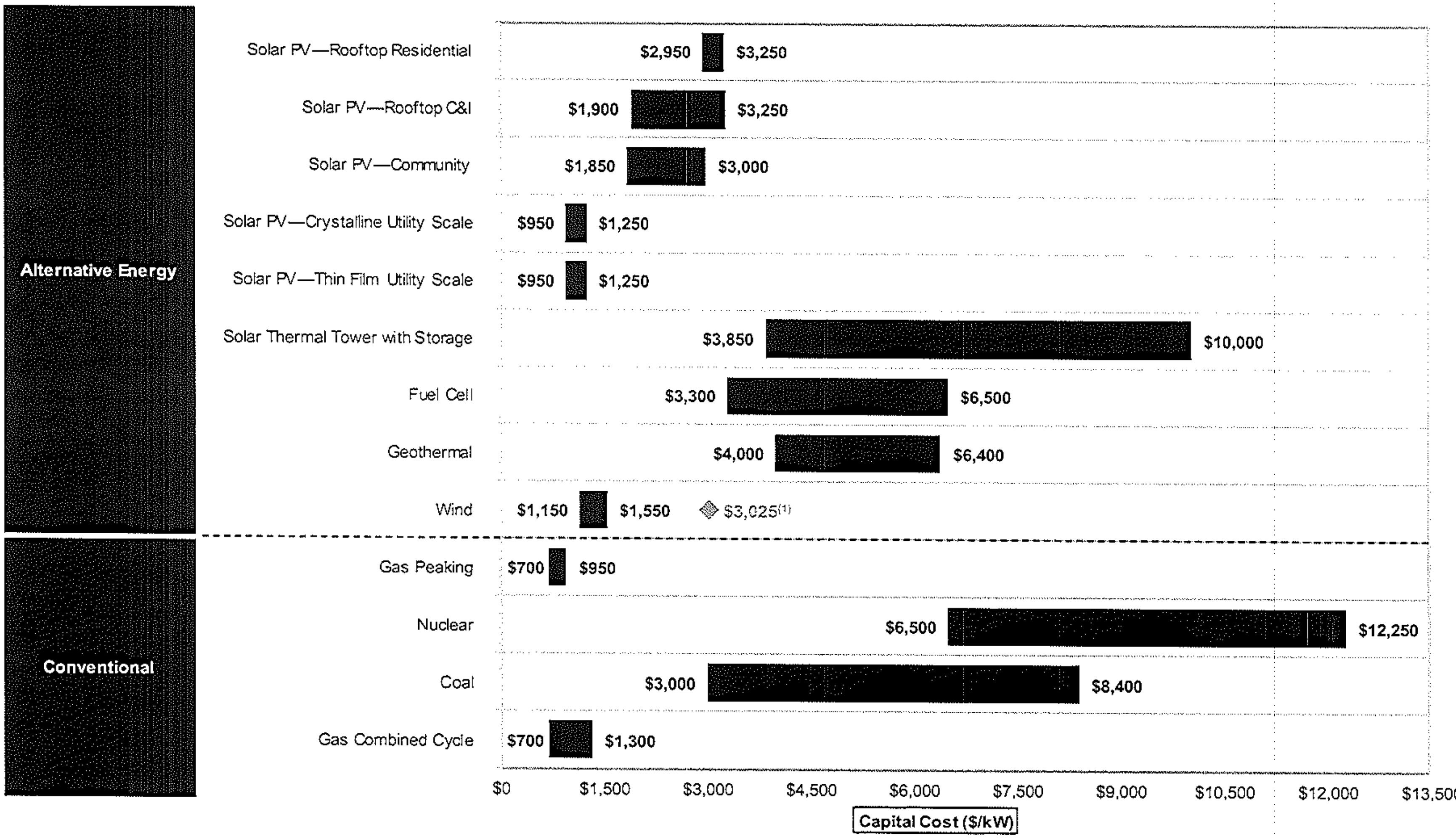
(3) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes a capacity factor of 10% for all geographies.

(4) Wind projects assume illustrative capacity factors of 38% – 55% for the U.S., 29% – 46% for Australia, 45% – 55% for Brazil, 25% – 35% for India, 31% – 36% for South Africa, 22% – 30% for Japan and 33% – 38% for Northern Europe.

(5) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes capacity factors of 43% – 80% on the high and low ends, respectively, for all geographies.

Capital Cost Comparison

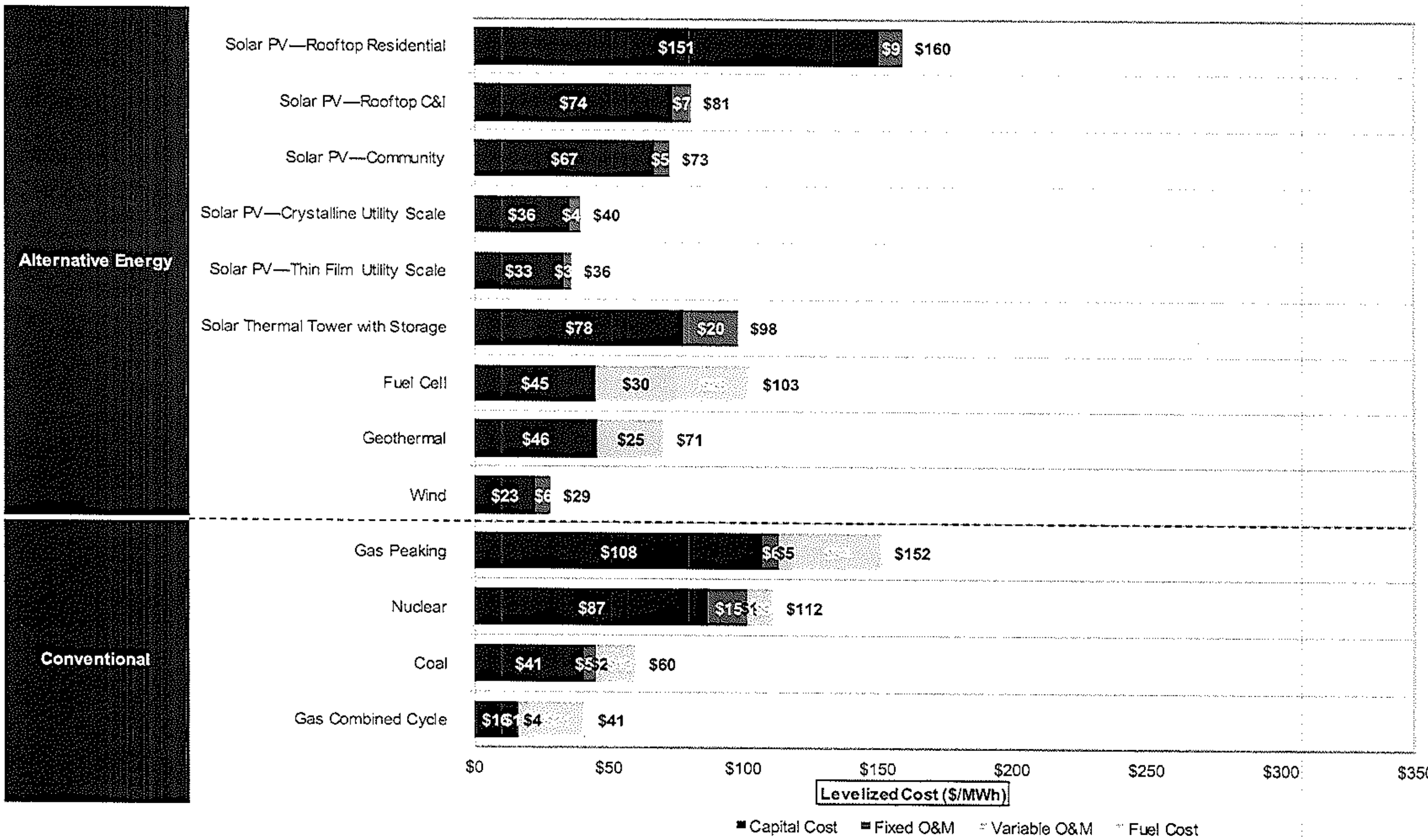
While capital costs for a number of Alternative Energy generation technologies are currently in excess of some conventional generation technologies, declining costs for many Alternative Energy generation technologies, coupled with uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in LCOE values



Source: *Lazard estimates.*
(1) Represents the estimated midpoint of the total capital cost for offshore wind.

Levelized Cost of Energy Components—Low End

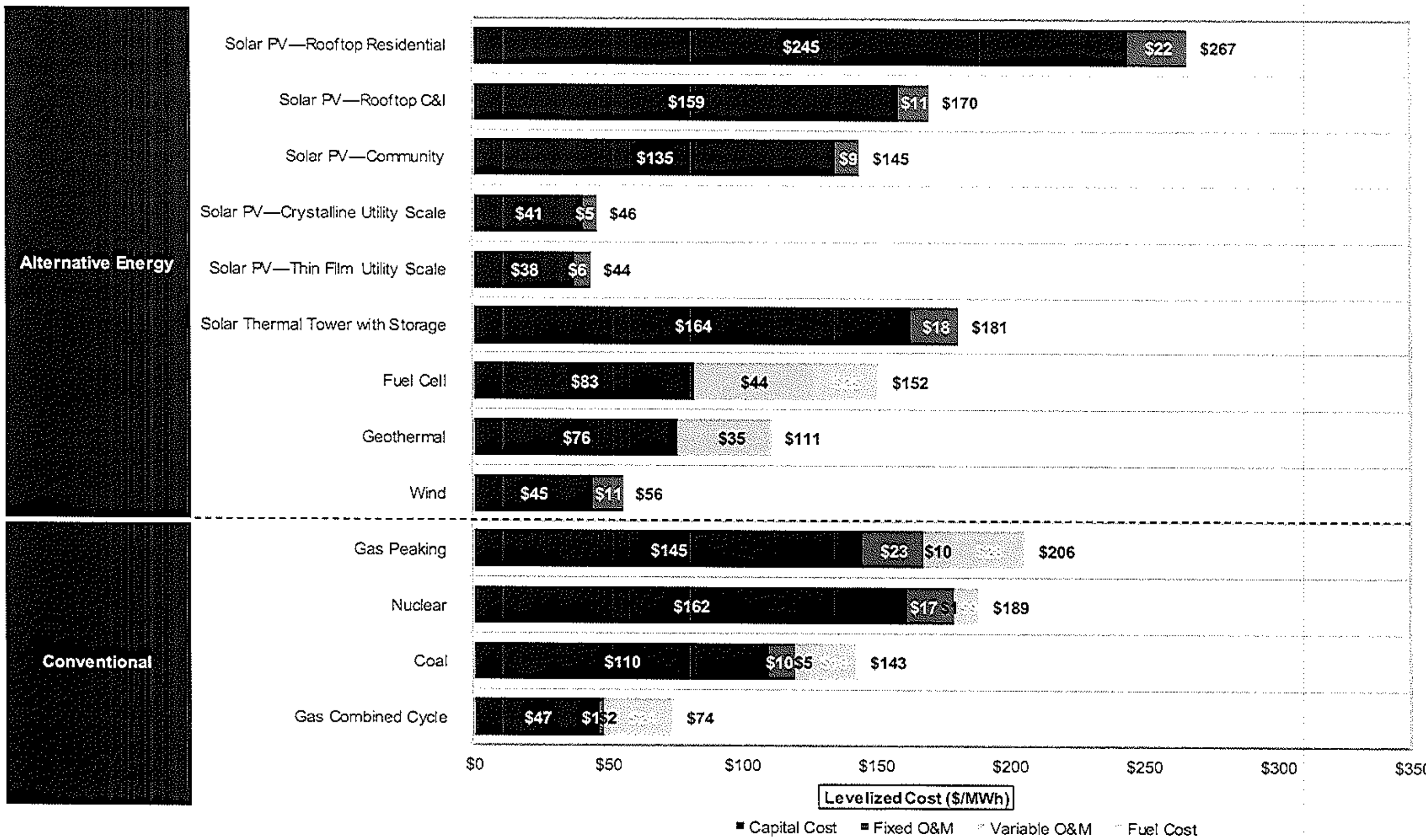
Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of Alternative Energy generation technologies is the ability of technological development and increased production volumes to materially lower operating expenses and capital costs for Alternative Energy generation technologies



Source: *Lazard estimates.*

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 Alternative Energy generation technologies is the ability of technological development and increased production volumes to materially lower operating expenses and capital costs for Alternative Energy generation technologies



Source: *Lazard estimates.*

Levelized Cost of Energy Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOE analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see appendix for detailed assumptions by technology)

Unsubsidized Wind — High Case Sample Illustrative Calculations

Year [1]		0	1	2	3	4	5		20
Capacity (MW)	(A)		150	150	150	150	150		150
Capacity Factor	(B)		38%	38%	38%	38%	38%		38%
Total Generation ('000 MWh)	(A) x (B) = (C)*		499	499	499	499	499		499
Levelized Energy Cost ($/MWh)	*(D)*		*$55.6*	*$55.6*	*$55.6*	*$55.6*	*$55.6*		*$55.6*
Total Revenues	(C) x (D) = (E)*		$27.8	$27.8	$27.8	$27.8	$27.8		$27.8
Total Fuel Cost	(F)		--	--	--	--	--		--
Total O&M	(G)*		5.5	5.6	5.7	5.9	6.0		8.4
Total Operating Costs	(F) + (G) = (H)		$5.5	$5.6	$5.7	$5.9	$6.0		$8.4
EBITDA	(E) - (H) = (I)		$22.3	$22.2	$22.0	$21.9	$21.8		$19.4
Debt Outstanding - Beginning of Period	(J)		$139.5	$136.7	$133.7	$130.5	$127.0		$24.8
Debt - Interest Expense	(K)		(11.2)	(10.9)	(10.7)	(10.4)	(10.2)		(2.0)
Debt - Principal Payment	(L)		(2.8)	(3.0)	(3.2)	(3.5)	(3.8)		(11.9)
Levelized Debt Service	(K) + (L) = (M)		($13.9)	($13.9)	($13.9)	($13.9)	($13.9)		($13.9)
EBITDA	(I)		$22.3	$22.2	$22.0	$21.9	$21.8		$19.4
Depreciation (MACRS)	(N)		(46.5)	(74.4)	(44.6)	(26.8)	(26.8)		--
Interest Expense	(K)		(11.2)	(10.9)	(10.7)	(10.4)	(10.2)		(2.0)
Taxable Income	(I) + (N) + (K) = (O)		($35.4)	($63.2)	($33.3)	($15.3)	($15.2)		$17.4
Tax Benefit (Liability) [2]	(O) x (tax rate) = (P)		$14.2	$25.3	$13.3	$6.1	$6.1		($7.0)
After-Tax Net Equity Cash Flow	(I) + (M) + (P) = (Q)	($93.0)[3]	$22.5	$33.5	$21.4	$14.1	$13.9		($1.5)
IRR For Equity Investors		12.0%							

Key Assumptions [4]	
Capacity (MW)	150
Capacity Factor	38%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$36.5
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years) [5]	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,550
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,550
Total Capex ($mm)	$233

Technology-dependent

Levelized

Source: Lazard estimates.
Note: Wind—High LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Assumes full monetization of tax benefits or losses immediately.
(3) Reflects initial cash outflow from equity investors.
(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

Energy Resources—Matrix of Applications

While the LCOE for Alternative Energy generation technologies is, in some cases, competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) 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**

		Carbon Neutral/ REC Potential	Location			Dispatch			
			Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Base-Load
Alternative Energy	Solar PV(1)	✓	✓	✓	Universal(2)	✓	✓		
	Solar Thermal	✓		✓	Varies	✓	✓	✓	
	Fuel Cell	✗	✓		Universal				✓
	Geothermal	✓		✓	Varies				✓
	Onshore Wind	✓		✓	Varies	✓			
Conventional	Gas Peaking	✗	✓	✓	Universal		✓	✓	
	Nuclear	✓		✓	Rural				✓
	Coal	✗(3)		✓	Co-located or rural				✓
	Gas Combined Cycle	✗		✓	Universal			✓	✓

Source: Lazard estimates.

(1) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(2) Qualification for RPS requirements varies by location.
(3) For the purposes of this analysis, carbon neutrality also considers the emissions produced during plant construction and fuel extraction.

Cost of Carbon Abatement Comparison

As policymakers consider ways to limit carbon emissions, Lazard's LCOE analysis provides insight into the implicit "costs of carbon avoidance", as measured by the abatement value offered by Alternative Energy generation technologies. This analysis suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost-effective means of limiting carbon emissions; providing an implied value of carbon abatement of $26 – $34/Ton vs. Coal and $10 – $25/Ton vs. Gas Combined Cycle

- **These observations do not take into account potential social and environmental externalities or reliability or grid-related considerations**

		Conventional Generation			Alternative Energy Generation			
	Units	**Coal**	**Gas Combined Cycle**	**Nuclear**	**Wind**	**Solar PV Rooftop**	**Solar PV Utility Scale**	**Solar Thermal with Storage**
Capital Investment/KW of Capacity [1]	$/kW	$3,000	$700	$6,500	$1,150	$2,950	$950	$3,850
Total Capital Investment	**$mm**	**1,800**	**490**	**4,030**	**1,162**	**8,673**	**1,558**	**5,044**
Facility Output	MW	600	700	620	1,010	2,940	1,640	1,310
Capacity Factor	%	93%	80%	90%	55%	19%	34%	43%
Effective Facility Output	**MW**	**558**	**558**	**558**	**558**	**558**	**558**	**558**
MWh/Year Produced [2]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$60	$41	$112	$29	$160	$36	$98
Total Cost of Energy Produced	**$mm/yr**	**$296** 2	**$203**	**$546**	**$140**	**$781**	**$178** 1	**$480**
CO_2 Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51	4.51	4.51 3	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($93)	$250	($155)	$485	($118) 4	$185
vs. Gas		—	—	$343	($63)	$578	($25)	$278
Implied Abatement Value/(Cost)	$/Ton							
vs. Coal		—	$46	($55)	$34	($108)	$26 5	($41)
vs. Gas		—	—	($137)	$25	($231)	$10	($111)

: Favorable vs. Coal/Gas : Unfavorable vs. Coal/Gas

Implied Carbon Abatement Value Calculation (Solar vs. Coal)—Methodology

4 Difference in Total Energy Cost (Solar vs. Coal) = 1 – 2
= $178 mm/yr (Solar) – $296 mm/yr (Coal) = ($118) mm/yr

5 Implied Carbon Abatement Value (Solar vs. Coal) = 4 ÷ 3
= $118 mm/yr ÷ 4.51 mm Tons/yr = $26/Ton

Source: *Lazard estimates.*
(1) Inputs for each of the various technologies are those associated with the low end LCOE.
(2) All facilities illustratively sized to produce 4,888 GWh/yr.

Ex. AA-D-24

Levelized Cost of Energy—Key Assumptions

	Units	Solar PV				
		Rooftop—Residential	Rooftop—C&I	Community	Utility Scale—Crystalline [2]	Utility Scale—Thin Film [2]
Net Facility Output	MW	0.005	1	5	50	50
Total Capital Cost [1]	$/kW	$2,950 – $3,250	$1,900 – $3,250	$1,850 – $3,000	$1,250 – $950	$1,250 – $950
Fixed O&M	$/kW-yr	$14.50 – $25.00	$15.00 – $20.00	$12.00 – $16.00	$12.00 – $9.00	$12.00 – $9.00
Variable O&M	$/MWh	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—
Capacity Factor	%	19% – 13%	25% – 20%	25% – 20%	32% – 21%	34% – 23%
Fuel Price	$/MMBtu	—	—	—	—	—
Construction Time	Months	3	3	4 – 6	9	9
Facility Life	Years	25	25	30	30	30
Levelized Cost of Energy	$/MWh	$160 – $267	$81 – $170	$73 – $145	$40 – $46	$36 – $44

Source: Lazard estimates.

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

(2) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 50 MW system in high insolation jurisdiction (e.g., Southwest U.S.).

Ex. AA-D-24

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

	Units	Solar Thermal Tower with Storage	Fuel Cell	Geothermal	Wind—Onshore	Wind—Offshore
Net Facility Output	MW	135 – 110	2.4	20 – 50	150	210 – 385
Total Capital Cost [1]	$/kW	$3,850 – $10,000	$3,300 – $6,500	$4,000 – $6,400	$1,150 – $1,550	$2,250 – $3,800
Fixed O&M	$/kW-yr	$75.00 – $80.00	—	—	$28.00 – $36.50	$80.00 – $110.00
Variable O&M	$/MWh	—	$30.00 – $44.00	$25.00 – $35.00	—	—
Heat Rate	Btu/kWh	—	8,027 – 7,260	—	—	—
Capacity Factor	%	43% – 52%	95%	90% – 85%	55% – 38%	55% – 45%
Fuel Price	$/MMBtu	—	3.45	—	—	—
Construction Time	Months	36	3	36	12	12
Facility Life	Years	35	20	25	20	20
Levelized Cost of Energy	$/MWh	$98 – $181	$103 – $152	$71 – $111	$29 – $56	$62 – $121

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

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

	Units	Gas Peaking			Nuclear			Coal			Gas Combined Cycle		
Net Facility Output	MW	241	–	50		2,200			600			550	
Total Capital Cost [(1)]	$/kW	$700	–	$950	$6,500	–	$12,250	$3,000	–	$8,400	$700	–	$1,300
Fixed O&M	$/kW-yr	$5.00	–	$20.00	$115.00	–	$135.00	$40.00	–	$80.00	$6.00	–	$5.50
Variable O&M	$/MWh	$4.70	–	$10.00	$0.75	–	$0.75	$2.00	–	$5.00	$3.50	–	$2.00
Heat Rate	Btu/kWh	9,804	–	8,000	10,450	–	10,450	8,750	–	12,000	6,133	–	6,900
Capacity Factor	%		10%			90%			93%			80%	
Fuel Price	$/MMBtu	$3.45	–	$3.45	$0.85	–	$0.85	$1.45	–	$1.45	$3.45	–	$3.45
Construction Time	Months	12	–	18	69	–	69	60	–	66	24	–	24
Facility Life	Years		20			40			40			20	
Levelized Cost of Energy	$/MWh	$152	–	$206	$112	–	$189	$60	–	$143	$41	–	$74

Source: Lazard estimates.

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

Summary Considerations

Lazard has conducted this analysis comparing the LCOE 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 environmental and social consequences of various conventional generation technologies, RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase and government subsidies in certain regions.

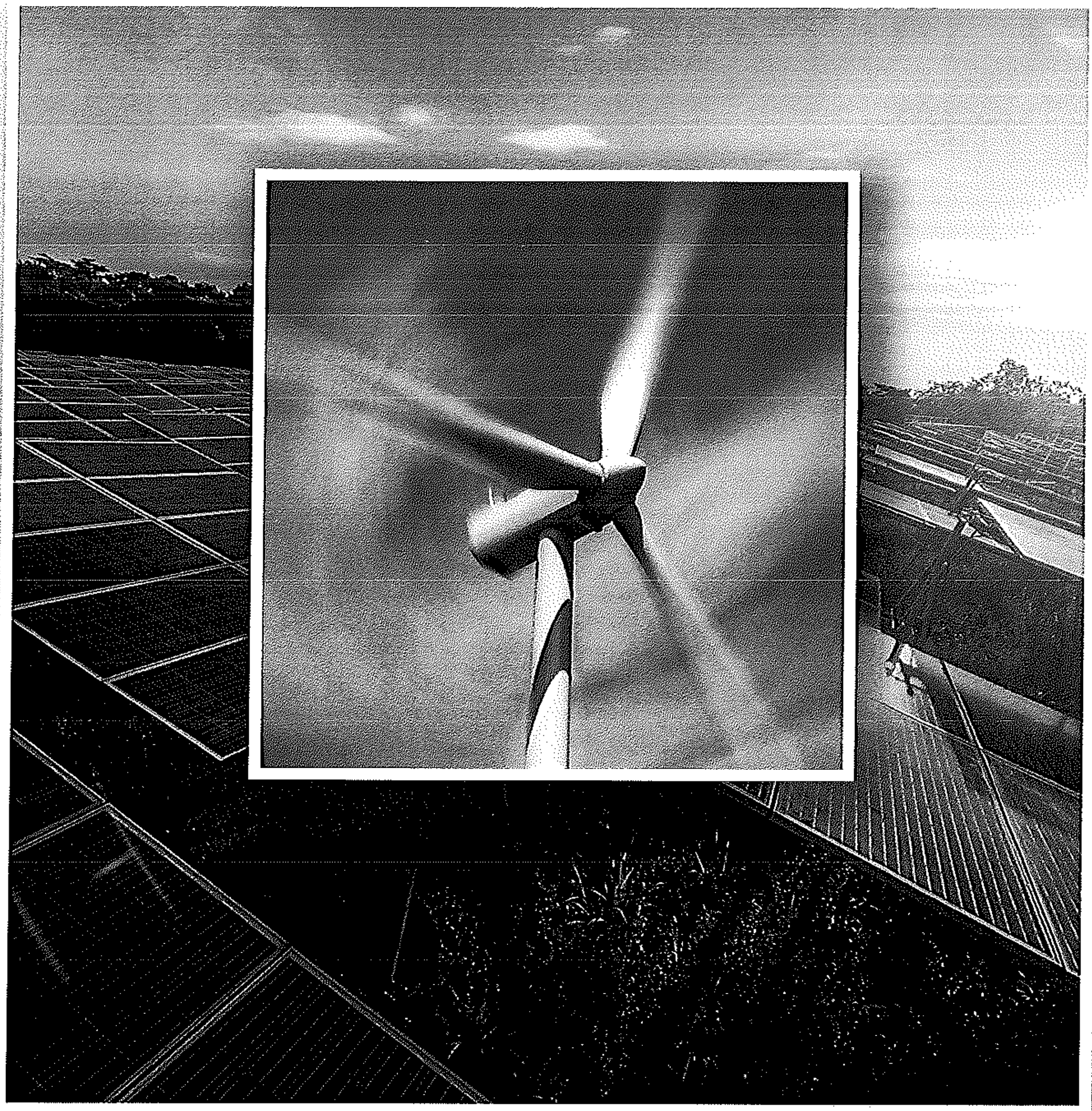
In this analysis, Lazard's approach was to determine the LCOE, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, etc.) were identical for all technologies in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and other important metrics on the LCOE. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This analysis (as well as previous versions) has benefited 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: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This 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, airborne pollutants, greenhouse gases, etc.).

Ex. AA-D-25

INTEGRATED RESOURCE PLAN UPDATE // SPRING 2019



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Ex. AA-D-25

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Ex. AA-D-25

1. Executive Summary

Ameren Missouri continues to execute on the preferred resource plan presented in its 2017 Integrated Resource Plan (IRP) filing. Our plan is focused on transitioning our generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion and achieves reductions in CO_2 emissions of 35 percent by 2030, 50 percent by 2040, and 80 percent by 2050, compared to 2005 levels. The plan includes continued customer energy efficiency program offerings, retirement of approximately half of our coal-fired generating capacity, which will be reaching the end of its useful life, and expansion of renewable generation, including the addition of at least 700 MW of wind generation by the end of 2020 and 100 MW of solar generation by 2027. By executing our plan, we will ensure that our customers' long-term electric energy needs are met in a safe, reliable, cost-effective and environmentally responsible manner.

Key steps that Ameren Missouri has taken since the filing of our 2017 IRP include:

- Received approval from the Missouri Public Service Commission (the Commission or the MoPSC) for the construction and acquisition of two wind projects – the up to 400 MW Terra-Gen High Prairie wind facility in northeast Missouri and the up to 157 MW EDF Brickyard Hills wind facility in northwest Missouri.
- Continued to work with developers for the acquisition of further wind projects to bring total wind resource additions to at least 700 MW by the end of 2020.
- Received approval from the MoPSC for our third three-year portfolio of customer energy efficiency programs and the addition of demand response programs under the Missouri Energy Efficiency Investment Act (MEEIA).
- Continued projects to close coal ash basins and switch to dry handling of coal ash ahead of EPA mandated deadlines.
- Published our report on climate-related risks, *Building a Cleaner Energy Future*, in March, 2019.
- Began to evaluate the proposed Affordable Clean Energy (ACE) rule regulating carbon dioxide emissions from electric energy centers.
- Filed our Smart Energy Plan with the Commission pursuant to Senate Bill 564. This forward-looking plan is designed to upgrade the electric grid and bring significant benefits to customers for decades. The plan includes $5.3 billion of electric and $1 billion in wind investments from 2019 through 2023 that will, among other things, accelerate our investment in smart grid technologies and renewable energy as we build the grid of the future, while keeping electric rates stable and predictable through the state's first-ever rate caps. The plan also

accelerates smart energy infrastructure construction that will drive job creation and economic development in Missouri.

2. Compliance Overview

2.1 Purpose of Annual Updates

Annual updates are required by 4 CSR 240-22.080(3). The rules indicate that the purpose of annual updates is to ensure that members of the stakeholder group have the opportunity to provide input and to stay informed regarding the items listed below.

- The utility's current preferred resource plan (see section 1)
- The utility's progress in implementing the resource acquisition strategy (see section 2.3)
- The status of the identified critical uncertain factors (see section 3.5)
- Analyses and conclusions regarding any special contemporary issues identified by the Commission (see Compliance References at the end of this report for the location of specific discussion on each issue)

Ameren Missouri has created this annual update report to satisfy the intended purpose established in the IRP rules and has updated its assessment of general planning conditions. Each item explicitly cited in the rules is addressed in the referenced chapter or section of this report as noted above.

2.2 Ameren Missouri's Approach to its Annual Update

In its Order in File No. EO-2012-0039 establishing special contemporary issues to be evaluated by Ameren Missouri in its 2012 IRP Annual Update, the Commission noted that, "the requirement to examine special contemporary issues should not be allowed to expand the limited annual update report into something more closely resembling a triennial compliance report." Ameren Missouri agrees with the Commission that the scope and depth of an IRP Annual Update should not be comparable to that for a triennial IRP filing. Also in its Order in File No. EO-2019-0065 establishing special contemporary issues for Ameren Missouri's 2019 IRP Annual Update, the Commission stated if the Company believes it has already adequately addressed some of these issues in its IRP filing or some other filing, then it does not need to undertake any additional analysis because of the special contemporary issue designation. The Commission stated the same approach is acceptable if the Company intends to address any of the issues in a future IRP filing.

On that basis, Ameren Missouri has relied heavily on the groundwork developed in its 2017 IRP as a basis for reviewing its assumptions and analysis and reporting its findings.

The Company also views the IRP Annual Update in its proper role as just that, an update on the nature of key variables and the conclusions that follow. Based on the conclusions drawn from the review and analysis discussed here, the Company believes that its preferred resource plan, as presented in its 2017 IRP filing, is still appropriate at this time. Should the Company's continued planning and consideration of relevant issues lead to a conclusion that its Preferred Resource Plan is no longer appropriate and should be replaced with a new Preferred Resource Plan, the Company will notify the Commission of its decision in accordance with 4 CSR 240-22.080(12).

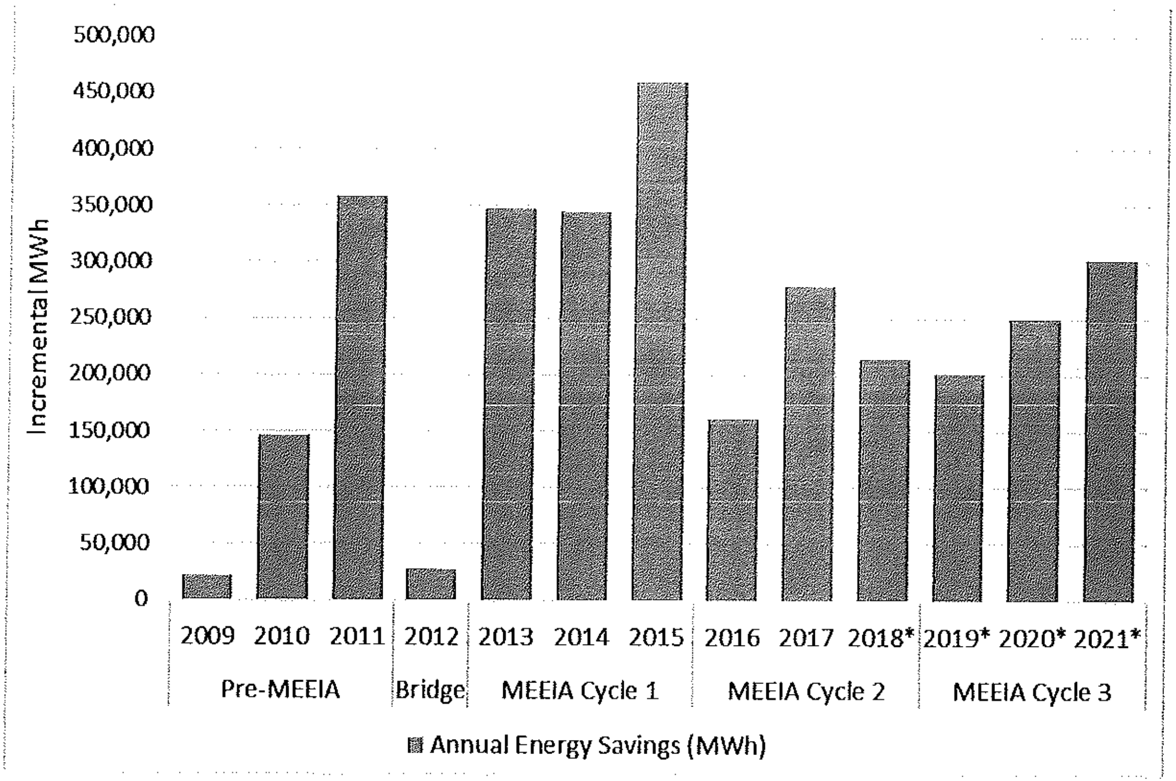
2.3 Implementation of Current Preferred Resource Plan

Ameren Missouri adopted a new preferred resource plan with its 2017 IRP filing. In that filing, the Company indicated that its new Preferred Resource Plan includes the addition of 700 MW of new wind generation and 100 MW of new solar generation and implementation of energy efficiency and demand response programs, as well as continued pursuit of demand side management (DSM) programs throughout the entire planning horizon at the Realistic Achievable Potential level. The Company also indicated that the implementation of future programs will depend on policies that reflect timely cost recovery, proper alignment of incentives, and appropriate earnings opportunities, as required by the MEEIA. Also included in the filing was an updated implementation plan. Following is an item-by-item update on the status of the implementation steps listed in the Company's 2017 IRP filing.

Demand-Side Resources Implementation

MEEIA requires that utility incentives be aligned with helping customers use energy more efficiently by providing timely recovery of program costs, elimination of the throughput disincentive and timely earnings opportunities. Ameren Missouri has successfully implemented its second three-year cycle of approved MEEIA programs (third three-year cycle of programs when counting pre-MEEIA activities) which commenced on March 1, 2016. Figure 2.1 below provides a summary of the annual energy savings, with 2012 being a "bridge" year from the Company's pre-MEEIA programs to the MEEIA programs.

Figure 2.1 Historical Ameren Missouri Energy Efficiency Program Savings



*2018-2021 results are net-as-filed; evaluation results are not yet available

Ameren Missouri filed its application for its third MEEIA portfolio of demand-side programs on June 4, 2018. Ameren Missouri worked with stakeholders to reach agreement on a portfolio that includes a three-year term for residential and business efficiency and demand response programs, while integrating a six-year implementation for income-eligible offerings. Included was a cost recovery and earnings opportunity mechanism that addressed the stakeholders' concerns with the Company's initial proposal. A stipulation and agreement was filed on October 25, 2018. The Commission unanimously approved Ameren Missouri's MEEIA 2019-21 stipulation on December 5, 2018.

Table 2.1 below provides a summary of the annualized energy savings and peak reduction goals, as well as budgets, for residential, business and income qualified programs in the Company's approved MEEIA 2019-21 portfolio. It should be noted that the goals and budgets are re-aligned on calendar years, therefore 2019 reflects a 10-month program year.

Table 2.1: MEEIA 2019-21 Implementation Plan (Annualized Savings)

	2019*	2020	2021	2022	2023	2024	Total
Estimated Program Net Savings MWh							
Low Income**	10,443	13,858	15,201	12,112	13,115	12,915	77,644
Residential ***	112,823	84,450	82,467	na	na	na	279,740
Business	78,696	152,847	205,044	na	na	na	436,587
TOTAL estimated net energy savings (MWH @ meter)	**201,962**	**251,155**	**302,712**	**12,112**	**13,115**	**12,915**	**793,970**
Estimated Program Net Savings MW							
Low Income **	2.4	3.4	4.1	4.2	4.7	4.7	23.4
Residential***	57.4	45.8	47.9	na	na	na	151.1
Business	44.4	64.5	77.4	na	na	na	186.2
TOTAL estimated net demand savings (MW @ meter)	**104.2**	**113.7**	**129.3**	**4.2**	**4.7**	**4.7**	**360.8**
Estimated Program Costs ($ millions)							
Low Income**	$5.41	$6.85	$8.19	$9.85	$11.04	$10.98	$52.32
Residential ***	$26.58	$28.39	$29.37	na	na	na	$84.34
Business	$18.15	$31.58	$40.93	na	na	na	$90.66
TOTAL Program Costs ($ millions)	**$50.14**	**$66.83**	**$78.48**	**$9.85**	**$11.04**	**$10.98**	**$227.31**

* The MEEIA 2019-21 goals and budgets are re-aligned on calendar years, therefore 2019 is a 10 month program year.

** The MEEIA 2019-21 plan included Low Income programs for a 6 year period and all other programs for a 3 year period.

*** Due to a one year persistence for the Behavior Modification Program, this is only included once in the table above.

The above summary matches Appendix A from the MEEIA 2019-21 Plan with all costs allocated.

Renewables

Ameren Missouri solicited proposals from wind developers through a request for proposal process for wind projects in order to meet Missouri's Renewable Energy Standard (RES) requirements as laid out in the preferred resource plan. Ameren Missouri signed the first contract for an up to 400 MW project in Northeast Missouri in April 2018 and applied for a certificate of convenience and necessity (CCN) in that same month. The CCN was granted by the Commission in October 2018. The Company signed a contract and applied for a CCN in October 2018 for an up to 157 MW wind project in Northwest Missouri. The Commission granted the CCN in March 2019. Ameren Missouri continues negotiations for a third wind project located in either Missouri or surrounding states to complete the required wind build-out for RES compliance and expects to have all three projects on-line by the end of 2020.

The Company is evaluating options for the deployment of solar resources, including resource investments required by Senate Bill 564.

Meramec Energy Center

Ameren Missouri reaffirmed its decision to retire the Meramec Energy Center by the end of 2022 in the 2017 IRP and is taking the necessary steps for retirement including the implementation of transmission system upgrades and required notifications to the Midcontinent Independent System Operator, Inc. (MISO).

Environmental

The Company continues to refine its estimates for environmental mitigation as part of its ongoing environmental compliance analysis. Dry fly ash systems and new wastewater treatment plants were completed at both the Labadie and Rush Island Energy Centers in 2018. Dry bottom ash projects were completed at Rush Island in 2018. Two remaining dry bottom ash systems at Labadie, on Units 1 & 2, are scheduled to be completed in 2019. Construction has started on dry ash handling and wastewater treatment systems at Sioux, with scheduled completion in 2020.

3. Planning Environment

3.1 Environmental Regulations

Ameren Missouri has reviewed its assumptions on the eventual requirements for pending environmental regulations. Table 3.1 summarizes the current and pending environmental regulations for which Ameren Missouri must implement mitigation measures, along with expectations for compliance requirements for certain potential regulations.

Ameren Missouri has made significant investments to comply with existing environmental regulations and maintain a sufficient compliance margin. Rules proposed or promulgated since the IRP filing in September of 2017 include revisions to the Clean Power Plan, final attainment designations for the national ambient air quality standards for ozone, revisions to the Coal Combustion Residual Rule and the proposal of Missouri regulations for the management of coal combustion residuals.

Table 3.1: Current & Pending Environmental Regulations

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Cross-State Air Pollution Rule (CSAPR)	Reduction in NOx and SO2 allowances vs. CAIR; New allowances for trading program (state level caps)	EPA implemented Phase 1 starting on 1/1/2015. On September 7, 2016 EPA finalized an update effective December 27, 2016 to lower the seasonal NOx (May-Sept) allocations beginning with the 2017 ozone season.	Phase 1: 1/1/2015 Phase 2: 1/1/2017
Revisions to National Ambient Air Quality Standards (NAAQS)	Lower PM, NOx and SO2 limits; Expansion of non-attainment areas	SO2 final rule June, 2010; EPA issued a final designation of "unclassifiable" for area around Labadie; final designations for all areas 2016-2020.	SO2: 2017 - 2020
		Fine particulate (PM2.5) lowered 1/15/2013; Attainment designations 03/2015; State Implementation Plans 2018.	Missouri in attainment EPA will review standard in 2020
		Ozone standard lowered, final rule 12/2015; Attainment designations complete April 2018; St. Louis/Metro East area marginal nonattainment and size of area reduced.	EPA will review standard in 2020
Mercury and Air Toxics Standards (MATS)	Reduction in emissions of Mercury, HCl (proxy for acid gases) and particulate emissions (proxy for non-mercury metals)	Final rule effective April 16, 2012. Compliance required by April 16, 2015.	Rush Island and Sioux Energy Centers compliant on April 16, 2015; Labadie and Meramec (units 3 & 4) Energy Centers received MDNR approved 1-yr extensions and compliant on April16, 2016.
Clean Air Visibility Rule (CAVR)/Regional Haze Rule	Application of Best Available Retrofit Technology (BART); Targets reduction in transported SO2 and NOx; status of CSAPR may require state to change approach.	Final rule issued by EPA in 1999; States submitted progress reports in 2013; CSAPR resolution may require changes to state rule.	EPA finalized a rule that will move the next deadline from July 31, 2018 to July 31, 2021.
Clean Water Act Section 316(a) Thermal Standards	Implementation through NPDES permit conditions	Evaluation covered by NPDES permits	2015 - 2020
Clean Water Act Section 316(b) Protection of Aquatic Life	Case-by-case determination of controls required to meet entrainment standards; national standard for impingement	Final rule from EPA effective October 2014	Study plans 2014; Studies 2015 - 2017; Compliance 2022 - 2024
Waters of The United States (WOTUS)	Protection of additional streams and tributaries	Final rule issued June 2015; the rule was challenged in several federal district courts. Case-by-case review of implementation while litigation continues. The EPA and Corps of Engineers proposed revisions to the definition on February 14, 2019; comment period closes April 15, 2019.	Final rule expected in 2019
Revisions to Steam Electric Effluent Limitations Guidelines (ELG)	Lower effluent emissions for existing parameters; Installation of wastewater treatment facilities; Implemented through NPDES permit conditions	EPA proposal April 19, 2013; final rule Sept 30, 2015; linked to CCR rule; revised rulemaking for steam electric power plant discharges effective January 4, 2016. The EPA has stayed compliance deadlines pending review of the final rule.	2018 - 2023
Coal Combustion Residuals (CCR)	Conversion to dry bottom ash and fly ash; Closure of existing ash ponds; Dry disposal in landfill	Final determination from EPA on haz/non-haz Dec 2014; final rule April 2015, effective October 19, 2015. Fedral legislation (WINN Act) to revise rule signed December 16, 2016. Missouri state rule proposed 2/01/2019; comment period closed 3/28/2019.	2018 - 2023
Clean Air Act Regulation of Greenhouse Gases (GHG)/Affordable Clean Energy Rule (ACE)	New Source Performance Standard (NSPS) for new, modified, reconstructed units	New unit NSPS re-proposed Jan 2014; final rule effective 12/22/2015. EPA proposed revisions to rule in December, 2018; comments closed 3/18/2019.	New unit NSPS applies 1/8/2014
		EPA isssued final rule for modified and reconstructed units effective 12/22/2015. EPA proposed revisions to rule in December 2018; comment period closed 3/18/2019. Challenges in DC Circuit Court held in abeyance.	Modified/reconstructed applies 6/18/2014
	State emission limits for existing sources	Clean Power Plan final rule was stayed by Supreme Court 2/9/2016; EPA proposed repeal and replacement of CPP with ACE rule in 2018; DC Circuit Court holding case in abeyance pending EPA replacement of CPP rule.	CPP was not implemented due to Supreme Court stay ACE rule proposed in August 2018 Final ACE rule expected June 2019

Clean Air Act Regulation of Greenhouse Gases/Affordable Clean Energy Rule[1]

In 2015, the EPA issued the Clean Power Plan, which would have established CO_2 emissions standards applicable to existing power plants. The United States Supreme Court stayed the rule in February 2016, and the Clean Power Plan was not implemented. The EPA has proposed to repeal and replace the Clean Power Plan. The U. S. EPA proposed the Affordable Clean Energy (ACE) rule in August 2018 as a replacement for the Clean Power Plan. The public comment period concluded in October 2018. The proposed rule would establish emission guidelines for states to follow in developing plans to limit CO_2 emissions from coal-fired electric generating units. The EPA proposes to define certain efficiency measures as the Best System of Emission Reduction (BSER). The EPA also proposed to update the New Source Review Permitting program to incentivize efficiency improvements at existing power plants. The EPA is expected to finalize the Affordable Clean Energy Rule in mid-2019.

The proposed ACE rule has several key components: 1) Defines BSER for greenhouse gas (GHG) emissions from existing power plants as on-site, heat-rate efficiency improvements; 2) provides states with a list of "candidate technologies" that can be used to establish standards of performance and be incorporated into their state plans; 3) updates EPA's New Source Review permitting program to incentivize efficiency improvements at existing power plants; and 4) aligns Clean Air act section 111(d) general implementing regulations to give states adequate time and flexibility to develop their state plans.

The Clean Air Act sets a framework in section 111(d) under which EPA issues guidelines that determine BSER for existing sources, and the states develop plans to establish standards of performance for their existing sources. The states then submit those plans to EPA for approval. The proposal gives states the flexibility to design a plan that, in the state's judgment, will work best under its particular circumstances. EPA also solicited comment on the range of state flexibility for state plans including the use of trading and averaging between sources.

EPA is proposing to provide states three years to develop state plans. The EPA would have 12 months to act on a complete state plan submittal. If states do not submit a plan or their submitted plan is not acceptable, EPA will have two years to develop a federal plan. A possible timeline based on a final rule in 2019 is for state plans to be due in 2022, EPA approval in 2023 and initial compliance no earlier than 2024.

[1] File No. EO-2019-0065 Paragraph 1.O (1)-(3)

Attainment Designations for the National Ambient Air Quality Standard (NAAQS) for Ozone

The air quality in the St. Louis area continues to improve. The EPA re-designated the St. Louis and Metro-East Illinois area to be in attainment with the 2008 eight-hour ozone standard. The EPA lowered the ambient standard for ozone from 75 ppb to 70 ppb in December 2015. EPA made final designations for about 85 percent of the country in November, 2017, however those designations did not include the St. Louis/Metro-East Illinois area. The EPA released final designations for the St. Louis/Metro-East Illinois area as well as the other remaining areas of the country on April 30, 2018. The final designation for the St. Louis area reduces the size of the nonattainment area by removing Jefferson County in Missouri and Monroe County in Illinois, as well as all but a small portion (Boles Township) of Franklin County in Missouri. The St. Louis/Metro-East Illinois ozone nonattainment area includes St. Louis City, St. Louis County and St. Charles County in Missouri and Madison and St. Clair counties in Illinois. The St. Louis area is designated as marginal which is the least severe category. Marginal areas have ozone design values from 71 ppb to 81 ppb. The St. Louis area has a design value of 72 ppb based on the last three years of monitoring data.

Coal Combustion Residuals

The federal Coal Combustion Residuals (CCR) rule was published April 17, 2015, and became effective October 19, 2015. It establishes national standards for the management of CCRs. The CCR rule is self-implementing, however in December 2016, Congress amended federal solid waste statutes to classify coal combustion residual units as "sanitary landfills" and authorized the states under the WIIN Act to develop programs that, following EPA approval, would act in lieu of the federal rule. Under the WIIN Act, each state may submit to EPA a permitting program or other system of approval to achieve compliance with the CCR rule or "other State criteria that [EPA] determines to be at least as protective as" that rule.[2] The amendments afford states flexibility in establishing a CCR management program, and state agencies are not required to adopt verbatim the federal CCR Rule. On February 1, 2019, the Missouri Department of Natural Resources (MDNR) proposed state rules to implement a CCR management program. The public comment period closed on March 28, 2019, and it is expected that the MDNR will finalize the state rules and submit the rules to EPA for review and approval in 2019.

While mitigation has been included in our analysis for current and certain potential future regulations, further changes in regulations are possible. The Company continues to monitor the potential for further changes in regulation that may impact resource planning

[2] Solid Waste Disposal Act ("SWDA") §4005 (d)(1)(B), 42 U.S.C. §6945(d)1)(B)

decisions. Table 3.2 below shows the capex and O&M assumptions for environmental mitigation.

Table 3.2: Environmental Mitigation Costs[3]

Facility	Environmental Mitigation	Regulation	In-Service Year	Cost (2019 & beyond, incl. AFUDC) $ Million	Annual O&M $ Million
Meramec	Ash Pond Closure	CCR	2022	39	0.3
	Activated Carbon	MATS	2016	-	0.2
	Groundwater Monitoring	CWA	2023	1	0.1
Meramec	Total Environmental			40	0.5
Labadie	Ash Pond Closure	CCR	2020	31	0.3
	Landfill Cells	CCR	2023	107	-
	Dry Ash Conversion	CCR	2019	35	-
	Waste Water Treatment Plant	ELG	2018	-	0.7
	Activated Carbon	MATS	2016	-	4.1
	Aquatic Life	CWA 316	2022	35	0.4
	Groundwater Monitoring	CWA	2021	1	0.1
Labadie	Total Environmental			209	5.5
Rush Island	Ash Pond Closure	CCR	2020	14	0.3
	Waste Water Treatment Plant	ELG	2018	-	0.4
	Activated Carbon	MATS	2014	-	1.2
	Fine Mesh Screens	CWA 316 (b)	2024	25	0.4
	Groundwater Monitoring	CWA	2023	0	0.1
Rush Island	Total Environmental			39	2.3
Sioux	Ash Pond Closure	CCR	2021	21	0.3
	Landfill Cells	CCR	2022	42	-
	Dry Ash Conversion	CCR	2020	64	-
	Waste Water Treatment Plant	ELG	2020	31	0.3
	Fine Mesh Screens	CWA 316 (b)	2023	16	0.2
	Activated Carbon	MATS	2014	-	0.1
	Groundwater Monitoring	CWA	2023	1	0.1
Sioux	Total Environmental			174	0.9
TOTAL	Total Environmental			462	9

3.2 Supply-Side Resource Review[4]

Ameren Missouri has analyzed cost and performance characteristics of a wide range of supply side resources in its 2017 IRP and has documented its analysis in Chapter 6 of its 2017 IRP filing. New supply side resources that were evaluated in the alternative resource plans in the 2017 IRP include the following;

[3] File No. EO-2019-0065 Paragraph 1.S (1)-(9)
[4] File No. EO-2019-0065 Paragraph 1.T

- Gas Combined Cycle
- Gas Simple Cycle Combustion Turbine
- Wind
- Solar
- Pumped Hydroelectric Energy Storage
- Nuclear

Since the development of costs for supply side resources for the 2017 IRP, Ameren Missouri's expectations associated with owning these resources, with the exception of solar and wind, have not materially changed.

For solar and wind resource costs, Ameren Missouri solicited input from stakeholders and received Lazard's Levelized Cost of Energy Analysis version 12.0 and NREL 2018 Annual Technology Baseline (ATB) from Renew Missouri and Clean Grid Alliance, respectively. Ameren Missouri updated its cost and capacity factor expectations using these recommendations along with costs based on the four wind projects that it either has signed agreements with or is in negotiation for.

Table 3.3: 2017 IRP vs 2019 Annual IRP Update Wind and Solar Characteristics (2019 $)

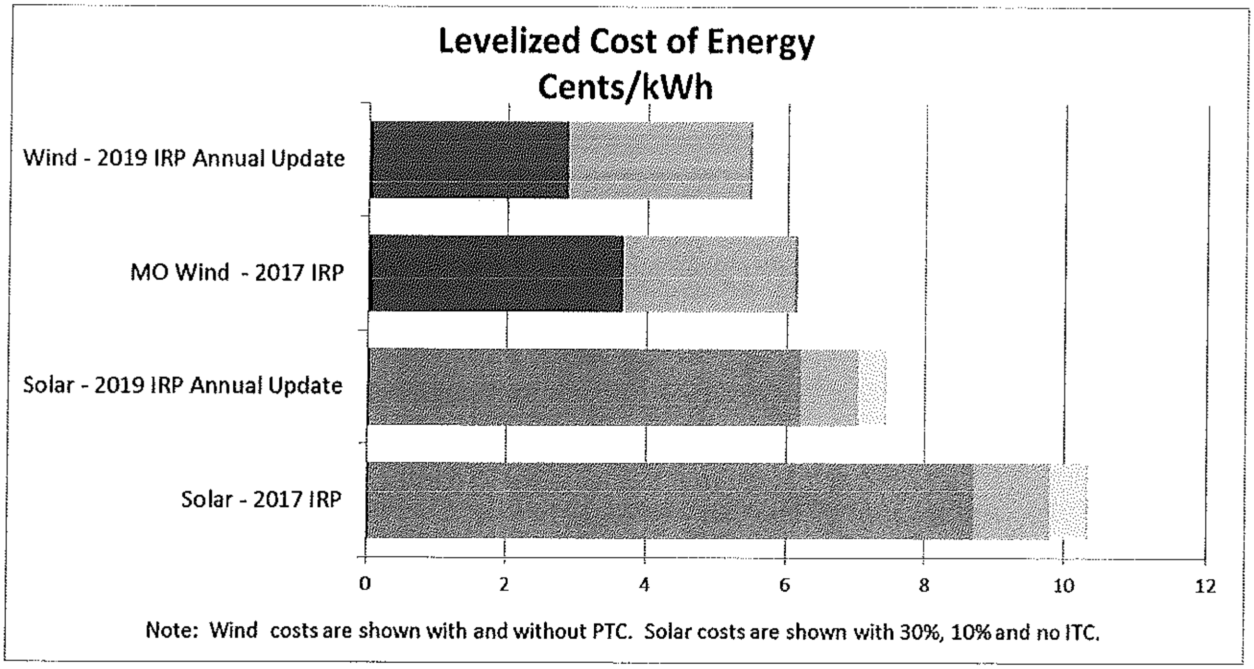
Resource Option	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capacity Factor (%)
Missouri Wind - 2017 IRP	$1,973	$28	$0	40%
Wind - 2019 IRP Annual Update	$1,594	$16	$0	41%
Solar - 2017 IRP	$1,665	$17	$0	19%
Solar - 2019 IRP Annual Update	$1,314	$9	$0	20%

It should be noted that solar costs reported in this table are based on AC power rating; NREL solar cost data has been converted to a $/kW AC rating using an inverter loading ratio of 1.3 as included in the 2018 ATB.[5]

[5] https://atb.nrel.gov/electricity/2018/index.html?t=su

The levelized cost of energy for wind and solar resources using the same financial assumptions as in the 2017 IRP are shown in the figure below. The estimates show the effects of cost declines from the 2017 IRP to 2019 IRP Annual Update. The figure also displays the reduction in costs when production cost credits (PTC) for wind, and investment tax credits (ITC) for solar are utilized.[6]

Figure 3.1: Levelized Cost of Energy



Because this is only an annual update and not a full IRP, Ameren Missouri has not performed a new screening analysis. A new supply side screening analysis will be performed as part of the development of Ameren Missouri's 2020 IRP. This will include both renewable and energy storage resources, which will be screened for inclusion in alternative plans, including any plans reflecting alternative retirement dates for existing coal-fired resources.[7]

Renewable Energy Offerings[8]

Senate Bill 564, among other things, allows the Commission to approve investments in small or pilot projects if the project is designed to advance the electrical corporation's knowledge of deploying certain technologies, including gaining operating efficiencies that result in customer savings and benefits.

[6] File No. EO-2019-0065 Paragraph 1.K
[7] File No. EO-2019-0065 Paragraph 1.R
[8] File No. EO-2019-0065 Paragraph 1.E; File No. EO-2019-0065 Paragraph 1.M (1)-(2); File No. EO-2019-0065 Paragraph 1.N; File No. EO-2019-0065 Paragraph 1.Q

Ameren Missouri filed its Smart Energy Plan with the Commission in February, 2019. The Smart Energy Plan includes a pilot portfolio to test microgrid technology, net metering inverters and other technologies to better understand future grid characteristics and needs and potential customer impacts. We plan to work with customers and universities to develop a test facility with a working microgrid and applicable technologies so we can evaluate the benefits associated with these devices and how they can best be integrated into the energy grid. Also included in the plan are investments in community solar and solar partnership projects along with other solar opportunities.

Ameren Missouri has initiated, and the Commission has approved, a number of programs that are designed to address the corporate social responsibility and/or renewable energy purchasing goals of commercial, industrial, institutional, and public-sector customers for increased access to renewable energy and distributed generation resources. For years, the Company has offered its Pure Power program – a voluntary program through which customers can obtain the benefits of renewable energy through the acquisition of the renewable energy credits associated with existing renewable generation. However, in response to increasing customer expectations for a more direct connection between their usage and energy generated by specific renewable generation facilities developed on their behalf, the Company has also initiated its Community Solar Program and its Renewable Choice Program.

The Community Solar Program is an option available to residential and small commercial customers to participate in the development of one megawatt of local solar resources and offset a part of their energy usage with generation from that resource. The Renewable Choice Program is a larger program, with up to 400 MW of wind capacity, designed for larger power users to choose to obtain access to renewable energy to offset some or all of their energy usage. The Renewable Choice Program was deliberately designed with municipal and other government entities' preferences for renewable energy in mind to enable the Company to accommodate goals or resolutions such as those adopted by the Board of Aldermen for the City of St. Louis. The program is only available to larger commercial and industrial customers that meet a demand qualification requirement, but it is available to all government entities regardless of the total demand of the electric account or accounts.

While both of these programs are limited in scale by the terms approved by the Commission, they both represent opportunities to meet growing customer demand for renewable energy options and to learn about customer interest in, and satisfaction with, the program structures. That information and continued assessment of customer preferences and needs create the potential to expand the existing programs in the future or develop new or related programs to further assist customers in meeting their renewable energy goals. The agreement that enabled the implementation of the Renewable Choice Program specifically contemplates that, once that program is fully subscribed, interested stakeholders will convene to determine whether and how additional renewable capacity should be developed in support of those goals.

Ameren Missouri is currently looking for ways to provide solar energy options to its low-income customers pursuant to the Joint Agreement signed by stakeholders resolving certain issues raised with our 2017 IRP. The Company participated in the Missouri NAACP Energy Justice Roundtable on October 30, 2018, to brainstorm with participants and explore options. The Company received input from NAACP representatives in the subsequent months regarding the potential elements of and effective low-income solar program. Ameren Missouri is working towards having a program proposal in the near future for its customers that reside in low-income communities.

On August 30, 2018, Ameren Missouri announced the donation of $5 million over the next three years to provide energy assistance and new programs for our limited income customers to address immediate needs and help them keep bills lower over time. In 2018, approximately $1 million was allocated to Ameren Missouri's energy assistance partners to provide immediate energy assistance to customers impacted by last summer's extreme temperatures. The remaining $4 million will be administered by Ameren Missouri's community partners through 2020 for additional energy-assistance programs and long-term sustained energy improvements, such as weatherization support and equipment repair.

Senate Bill 564 also requires Ameren Missouri to invest $14 million in utility-owned solar facilities through the end of 2023. Under this act, an electrical corporation's decision to invest in utility-owned solar facilities shall be deemed prudent, and permission from the Commission for construction of such facilities shall not be required. Ameren Missouri has not made a final decision on the specifics of how it will comply with this portion of the new law. The scope of implementation may include investment in some of the projects described above, specifically in our efforts to develop solar projects in low income areas of the Company's service territory.

Existing Resources

A detailed analysis for Ameren Missouri's existing resources was included in the 2017 IRP along with evaluation of alternative resource plans that included early retirement of two of its coal-fired energy centers. Analysis of these alternative resource plans resulted in significant expected cost increases to customers. Figure 3.2 shows the total variable costs (fuel and non-fuel) for coal energy centers in the MISO market. With the exception of Meramec Energy Center, which is scheduled to retire by the end of 2022, all Ameren

Missouri coal-fired energy centers are in the lowest-cost quartile of the coal-fired plants within the MISO footprint.[9]

Figure 3.2: MISO Coal Plant Variable Cost (Fuel and Non-Fuel)[10]**

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Securitization[11]

As indicated in the MoPSC Order in File No. EO-2019-0065, some point to securitization as a potential tool for transitioning utility generation fleets from coal to renewable generation. While there are likely to be significant complexities when it is executed, the concept itself is relatively straightforward, and securitization has been used by utilities or proposed for the recovery of costs in the context of utility restructuring, retirement of coal and nuclear generation, investments in pollution controls, and disaster recovery due to

[9] File No. EO-2019-0065 Paragraph 1.L
[10] Source: FERC Form 1 via SNL (Major 500 – 514 for Individual Energy Centers)
[11] File No. EO-2019-0065 Paragraph 1.F

major events such as storms and fires. For the specific application of securitization referenced in the MoPSC Order, the process includes the following steps:

- The utility determines that accelerated retirement of a coal-fired generator or generators is appropriate.
- The utility establishes a Special Purpose Entity (SPE) to issue bonds backed by a statutorily guaranteed revenue stream via a non-bypassable charge on utility customers' bills; the bonds thus carry the highest ratings from the rating agencies.
- The SPE issues the bonds and exchanges the net proceeds (after issuance costs) for the remaining balance of the utility coal assets being retired.
- The principal and interest payments on the bonds are serviced by the guaranteed customer revenue stream via a trust.
- The utility uses the proceeds received from the SPE to invest in renewable generation assets.

As is evident, the employment of securitization in this context is dependent on the adoption of appropriate and workable legislation, followed by several key decisions on the part of the utility. First, the utility must determine that it is appropriate to accelerate the retirement of coal-fired assets. As with any resource planning decision, a decision to accelerate the retirement of coal generation includes consideration of long-term economics, customer rate impacts, emission reduction goals, and other objectives as well as risks including those associated with reliability, system operations, financing, and regulation. Such considerations were accounted for in the Company's 2014 decision to accelerate the retirement of its Meramec Energy Center and the depreciation of its associated plant investment.

Second, the utility must determine that it is appropriate to expand its investment into renewable generation beyond its existing plans in conjunction with the aforementioned accelerated coal retirement. Such a decision necessarily includes consideration of those factors mentioned above in the discussion of coal retirement decisions. It may also include consideration of compliance with renewable portfolio standards, such as Missouri's RES, programs offering customers the option of meeting their energy needs with renewable energy, such as Ameren Missouri's Renewable Choice Program, or other planning and policy drivers.

Third, the utility must determine that the use of the securitization approach outlined above is an appropriate step for executing on the first two decisions. By its nature, securitization is a complex undertaking that involves coordination among the utility seeking to execute the strategy, rating agencies who establish the ratings for the bonds, and the MoPSC, which reviews and approves the securitization plans. Because implementing securitization is complex, it is extremely important that the decisions regarding coal retirement, renewable investment, and the securitization strategy are meticulously planned. It may also involve some degree of pre-approval for utility actions undertaken to execute the plan. The utility must also consider other alternatives for achieving its objectives with respect to potential accelerated coal retirements and additional investments in renewable generation. Such alternatives may include accelerating the retirement date of coal units and increasing the annual depreciation expense as a result, traditional financing, and tax equity financing. Ameren Missouri continues to execute its acquisition of renewable generation pursuant to its preferred resource plan using a traditional financing approach.

At this time, Ameren Missouri has not yet made decisions with regard to accelerating the retirement of coal generation beyond its Meramec Energy Center nor any additional investments in renewable generation associated with such accelerated retirements. While no such decisions have yet been made, the availability of securitization as a potential tool for accelerated coal retirements and renewable investments could provide another viable option and additional planning flexibility for utilities when considering such decisions. The potential value of this option and flexibility depends in large part on the specific provisions of the necessary statutory authority that would have to be carefully crafted through the legislative process. Ameren Missouri is open to further discussion and exploration of this idea to determine its value and viability.

3.3 Transmission and Distribution Review[12]

Ameren Missouri continues to maintain and replace aging infrastructure to serve its customers. The Company has filed its Smart Energy Plan that includes investments to transform its system to a stronger and smarter grid to meet its customers' rising expectations for greater reliability, security and control over their energy usage. Ameren Missouri will be implementing over 2,000 Smart Energy Plan projects to provide customers with improved safety, security, reliability and resiliency, while also committing to keeping rates stable and predictable. Some examples of these projects are:

- Automating the electric distribution system to help isolate problems and restore service more quickly following storms and other power interruptions by deploying switching devices and accompanying communications technologies to build self-healing power lines, which are designed to significantly reduce the length of outages.
- Hardening the electric distribution system to better withstand severe weather. This includes 12,000 new utility poles for storm hardening, many fortified with composite materials and stronger equipment.

[12] File No. EO-2019-0065 Paragraph 1.G

- Employing smart grid technologies (e.g., relaying, monitoring, fault information, communications) as we upgrade existing substations and construct new ones.
- Developing a communications network to monitor and enable analytics from connected grid devices. To enable the grid of the future, the system requires a smarter, stronger and more secure communications network with far greater bandwidth. Our plan is to develop a wireless footprint statewide, starting with the St. Louis metropolitan area.

Smart Meter Program[13]

The Smart Meter Program (SMP) is part of Ameren Missouri's Smart Energy Plan and is being implemented to modernize Ameren Missouri's metering system. Ameren Missouri was one of the first utilities in the country to install Automated Meter Reading (AMR) technology across its system more than 20 years ago to help maintain customer affordability. While AMR has provided benefits to our customers, it doesn't allow for two-way information flow and can't provide real-time information to our customers. The SMP includes replacing all electric meters, gas modules, and the associated communication network in the Missouri service territory over approximately seven years beginning in 2019:

- 1.2 million electric advanced metering infrastructure (AMI) meters (residential and commercial/industrial) with remote connect/disconnect (RCD) capability for residential meters.
- 130,000 gas AMI modules (residential and commercial/industrial, not including new gas meters, only the communication module of the meters).
- RF mesh network, enabling two-way communication.
- Modifying the existing Meter Data Management System and Head End System to accept Ameren Missouri data.
- Upgrading the Dorsett Meter Shop to facilitate the receipt and testing of AMI meters.
- Creation of an Ameren Missouri Network Lab and Integrated Operations Center.

This project is estimated to cost a total of $392.4 million in capital investment based on a 100% deployment assumption by December 2025.

The project cost estimate includes 15 months to design and build out the digital (information technology) system, followed by five and a half years for electric meter, gas module, and network purchase and deployment. As a provision within the Smart Energy Plan (SEP), this project is subject to a yearly expenditure cap of 6% of Ameren Missouri's total capital spend which dictates the length of the deployment. Network deployment will

[13] File No. EO-2019-0065 Paragraph 1.D

begin in early 2020, electric meter deployment will begin in mid-2020, and gas module deployment will begin in 2024.

Table 3.4: SMP Capital Investment ($Million)

Prior Costs	2019	2020	2021	2022	2023	2024	2025
$6	$49	$48	$62	$57	$51	$60	$59

The SMP team has identified and categorized the AMI benefits into 2 categories:

- **Operational Benefits** – $309 Million reduction in operations and maintenance (O&M) costs. Examples of these cost reductions are the elimination of AMR meter read fees paid to our AMR vendor and elimination of fees paid to contractors to manually disconnect and reconnect customers.
- **Customer Benefits** – These benefits may still have a small impact on O&M costs, but mainly are a customer benefit or improved functionality.

Customer Benefits:

Lower Overall Cost of Service:

Reduction in truck rolls for numerous activities (Service Extenders, Reprogramming, and Testing).

This will allow for additional focus on other customer priorities.

Will allow for efficient deployment of line assets during storms and outage events

AMI technology will detect anomalous energy patterns, reducing non-technical usage, avoiding unneeded energy costs and increase revenue

Improved Billing:

Reduction in estimated billing

Increased Meter accuracy

Outage Management:

Will allow Ameren MO to obtain outage information quickly and send out notification when power has been restored

Increased Customer Functionality (Future Development):

Increased Rate Options such as TOU

Peak Time Rewards (Demand Response)

Convenience Pay (Pre-Pay)

Manage Energy Use:

Empowers customers to manage energy usage through alerts or viewing the web

Enables customers to analyze how their living habits, home improvements, and the weather impact their bill

Energy Efficiency:

Improved web functionality provides energy-saving recommendations

Allows customers to build a tailored energy savings plan and track progress

Enhanced Services:

Allows customers to take advantage of targeted promotions based on their customer profile

Faster reconnect response time

Ameren Missouri SMP implementation can be adapted to meet customer expectations for new energy products and services such as demand response, additional time of use tariffs, and improvements to the intelligent storm response systems. Additionally, customers will see improved usage insights and outage communications. The financial analysis for the Smart Meter Program is provided in Appendix A.

Ameren Missouri had analyzed conservation voltage reduction (CVR) in its 217 IRP. In that filing, Ameren Missouri indicated that smart meters that can communicate voltage levels along the distribution circuit need to be in place for CVR. With the SMP implementation, a CVR program that saves energy may be possible in the near future.[14]

Transmission Costs[15]

Ameren Missouri updated its cost expectations for transmission upgrades needed for Meramec Energy Center retirement to $92 Million (nominal $). Ameren Missouri's expectations on transmission interconnection costs for new supply-side resources as well as the transmission system upgrade costs that might be incurred following retirement of its existing coal-fired energy centers, with the exception of Meramec Energy Center transmission upgrade costs have not materially changed since the 2017 IRP. These costs can be found in Chapter 7 of the 2017 IRP filing.

3.4 Demand-Side Resource Review

Ameren Missouri began offering energy efficiency programs to its customers in 2009, and has implemented the largest portfolio of utility energy efficiency programs in Missouri with its MEEIA Cycle 1 & 2 energy efficiency portfolios in 2013-2018. Ameren Missouri's third cycle of MEEIA energy efficiency programs was approved by the Commission on December 5, 2018, and Ameren Missouri began implementation in March 2019.

Ameren Missouri has conducted a comprehensive DSM potential study with the assistance of a nationally recognized independent contractor to estimate demand-side resource potential that was used in its 2017 IRP and that informs the MEEIA Cycle 3

[14] File No. EO-2019-0065 Paragraph 1.H
[15] File No. EO-2019-0065 Paragraph 1.C

energy and demand savings and cost estimates. The comprehensive DSM potential study, which was included in the 2017 IRP filing, reviewed and considered the impact of foreseeable emerging energy efficiency and demand response technologies throughout the planning period.[16] In its 2017 IRP, Ameren Missouri evaluated alternative resource plans without any further deployment of DSM resources after MEEIA Cycle 2; these included add at least 1,800 MW of new supply-side resources to meet the load and reserve margin requirements.[17]

Ameren Missouri has initiated development of its 2019 DSM Market Potential Study that will inform its next triennial IRP filing. The 2019 Market Potential Study will also consider the impact of emerging energy efficiency and demand response technologies, and it will also ensure we capture data needed to evaluate what would be required in a DSM program to address customers' needs that might otherwise "opt out" of participation in MEEIA. Sources utilized to identify primary drivers for a customer to opt out will include Ameren Missouri customers that are currently opted out or have indicated plans to opt out. Results of the evaluation will be applied to existing DSM Programs and potential future programs to identify the effect on program costs, program cost effectiveness, associated charges to customer classes, and ability to achieve estimated savings targets.[18]

Electric Vehicle Charging Infrastructure[19]

Electric vehicle (EV) charging infrastructure, in and of itself, is by definition not a resource that can be used by the Company to meet its customers' energy or capacity needs. To that end, charging infrastructure cannot itself be screened as a resource. The very existence and availability of charging can, however, encourage EV adoption by customers. Those EVs represent a flexible load that may have the potential to become a valuable resource in time. Because EVs consume energy from batteries, the timing of the charging of batteries can be managed. Rate options and/or demand response programs can, therefore, be designed to take advantage of this flexible load resource. The first step in building this resource is to encourage the adoption of EVs, so that there is load to be managed. The Company has analyzed the ability of charging infrastructure to be a cost-effective means to encourage EV adoption in the context of its proposed Charge Ahead program (File No. ET-2018-0132) and has proposed a third party incentive approach to developing this infrastructure to encourage this beneficial load. The Company's current plans regarding EV infrastructure, as discussed in section 3.6 of this report, are focused

[16] File No. EO-2019-0065 Paragraph 1.U
[17] File No. EO-2019-0065 Paragraph 1.G
[18] File No. EO-2019-0065 Paragraph 1.I
[19] File No. EO-2019-0065 Paragraph 1.P

on this approach, rather than the ownership model that is enabled by the Court of Appeals, Western District's decision in KCP&L v. PSC, No. WD80911 (Aug. 7, 2018).

As EV load grows on the system, as mentioned above, that load has the potential to be a valuable resource. In the Company's 2016 Market Potential Study, rates to shift EV charging to off-peak were screened as a measure and were determined not to be cost effective. However, metering, communications, smart charging, and other technologies are evolving rapidly and the Company continues to monitor these developments. The Company will continue to screen EV-related rate and DR options in the context of that evolution in its 2019 Market Potential Study.

Distributed Energy Resource Potential[20]

The continued advancement of distributed energy resources (DER) is driving additional focus on a broad range of distributed resources. These include energy efficiency (EE), demand response (DR), energy storage, and distributed generation (DG) such as solar photovoltaic, wind, and combined heat and power (CHP). Ameren Missouri has performed potential studies covering EE, DR, DG, and CHP specifically and will continue to evaluate these types of DERs in future potential studies. Please refer to Chapter 8 – Demand-Side Resources and associated appendices in the Company's 2017 IRP filing for full details of our potential assessments for these resources. Ameren Missouri has also included in its IRP supply-side screening evaluations consideration of utility-owned DG resources, such as solar photovoltaic, reciprocating engine, and battery storage technologies. These and possibly other DG technologies will continue to be evaluated as part of future IRP analyses. Finally, Ameren Missouri has included estimates for penetration of customer-owned solar generation as part of its IRP load forecasting analysis, with three different levels of penetration corresponding to our base, high and low load forecasts. We will continue to evaluate the potential deployment of DERs as part of our ongoing IRP analysis.

Ameren Missouri maintains a database of customer-owned generation in conjunction with net-metering agreements and makes an annual filing with the Commission that summarizes the number of net-metered customers, capacity and energy received by Ameren Missouri in accordance with 4 CSR 240-20.065 (10)(A). Utility-owned resources are listed in our supply-side analysis chapter of the 2017 IRP.

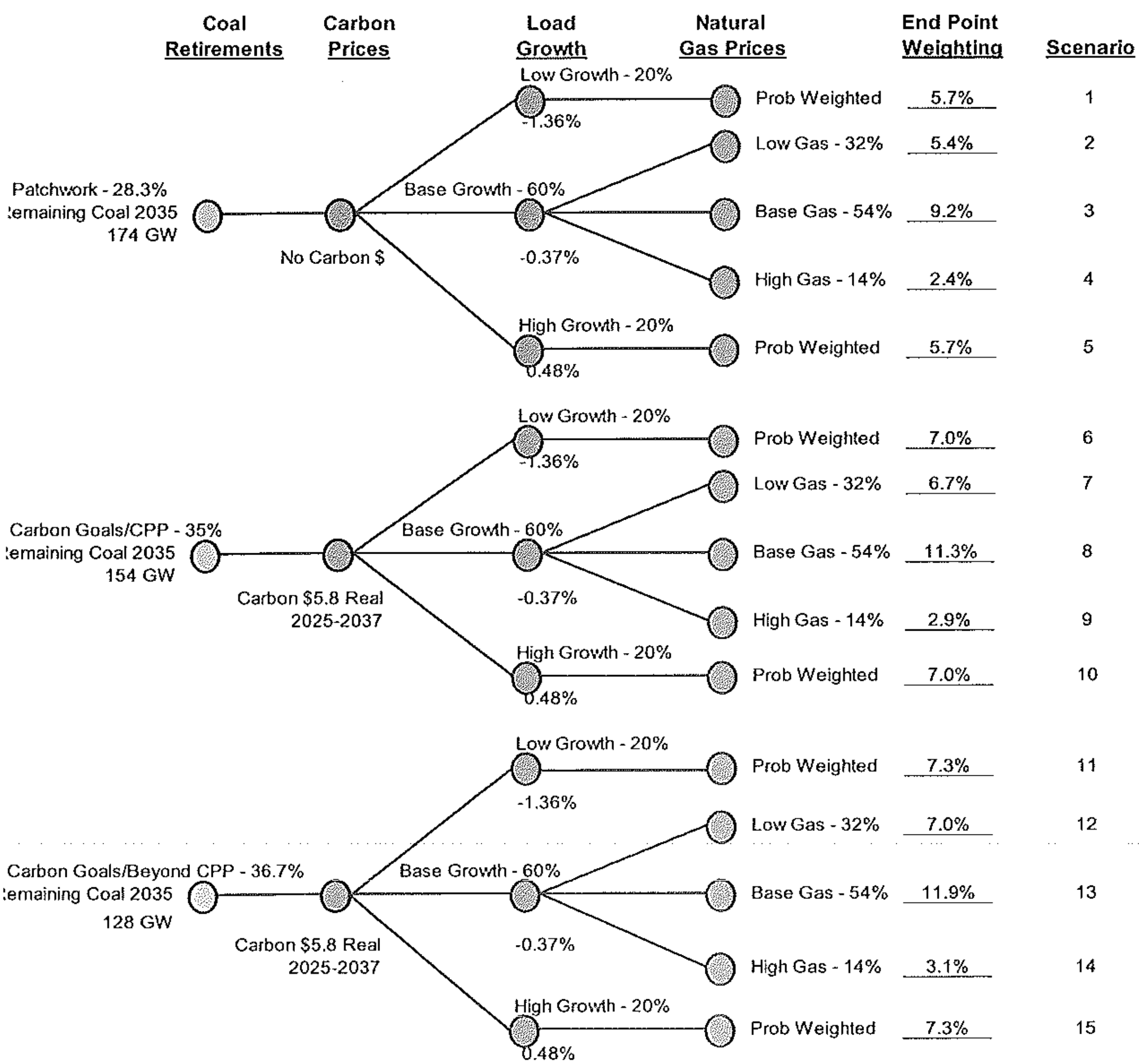
[20] File No. EO-2019-0065 Paragraph 1.A (1)-(3)

3.5 Uncertain Factors

3.5.1 Price Scenarios

Ameren Missouri has reviewed its assumptions for load growth, coal retirements, carbon prices, and natural gas prices, which are the major drivers of power prices. As discussed in more detail in this section, Ameren Missouri has determined that its current expectations for these driver variables are within the ranges established in the 2017 IRP. As a result, it is not necessary to update our power price scenarios. Each unique combination of uncertain factors is probability weighted and allows for analysis over a wide range of potential future conditions. Figure 3.3 shows the scenario tree from the 2017 IRP.

Figure 3.3: Scenario Tree



Coal Retirements

As specified in the 2017 IRP, a range of coal retirements was assumed to reflect a variety of factors that can significantly affect power prices over the 20-year planning period. The range of retirements is intended to capture the effects of market pressures on existing coal resources. This includes increasing investment in renewable generation resources, greater investment in efficient gas-fired generation and potential future environmental regulations. The current expectations for coal plant retirements have not materially changed from our assumptions in the 2017 IRP.

As of January 2019 the most current Annual Energy Outlook (AEO) includes a reference case that reflects an expected 101 GW of coal retirements. This reference case generally assumed only current laws and regulations are in place throughout the study period and does not make additional assumptions that may accelerate this retirement expectation. All of our cases include a higher level of coal retirements than this reference case assumption. The pressures that accelerate coal retirements are considered to be greater than those that are currently reflected in regulations. To highlight this effect of changing expectations, one of the cases reflected in the AEO for 2019 is characterized as a "High Oil and Gas Resources and Technology case," which represents a future with lower gas prices. These effects are due to advancing technology and productivity gains associated with higher oil production. In this case coal retirements increased from 101 GWs in the reference case to 129 GWs.

Figure 3.4 shows the assumptions used in the 2017 IRP and continues to reflect our planning assumptions.

Figure 3.4: Coal Retirement Assumptions

2017 IRP Assumptions	
Remaining Coal	**Carbon Prices**
Low - 28.3% Remaining Coal 2035 174 GW 127 GW Retired from 2016 Levels	No Carbon $
Base - 35% Remaining Coal 2035 154 GW 150 GW Retired from 2016 Levels	Carbon $5.8 Real 2025-2037
High 36.7% Remaining Coal 2035 128 GW 178 GW Retired from 2016 Levels	Carbon $5.8 Real 2025-2037

Carbon Dioxide Emission Prices

In addition to coal plant retirements, the above figure shows the carbon price expectations assumed in the 2017 IRP. We used a CO_2 emissions price as one of the factors that would affect CO_2 emissions in two of three cases but would not be the only, or even the main driver of reduced CO_2 emissions in each case.

This perspective is also in alignment with the 2019 AEO. As the two charts from the 2019 AEO below illustrate, even in the reference case, carbon intensity is expected to decline in the electric power industry based on the reduced usage of coal resources and an increasing reliance on renewable and natural gas generation. This expectation is in alignment with all of our cases, even with a zero or a small CO_2 value. All three of our coal retirement scenarios assume greater levels of coal retirements than the 2019 AEO reference case and therefore each will provide a lower level of carbon intensity than is reflected below.

Figure 3.5: U.S. Electricity Fuel Mix and Carbon Intensity

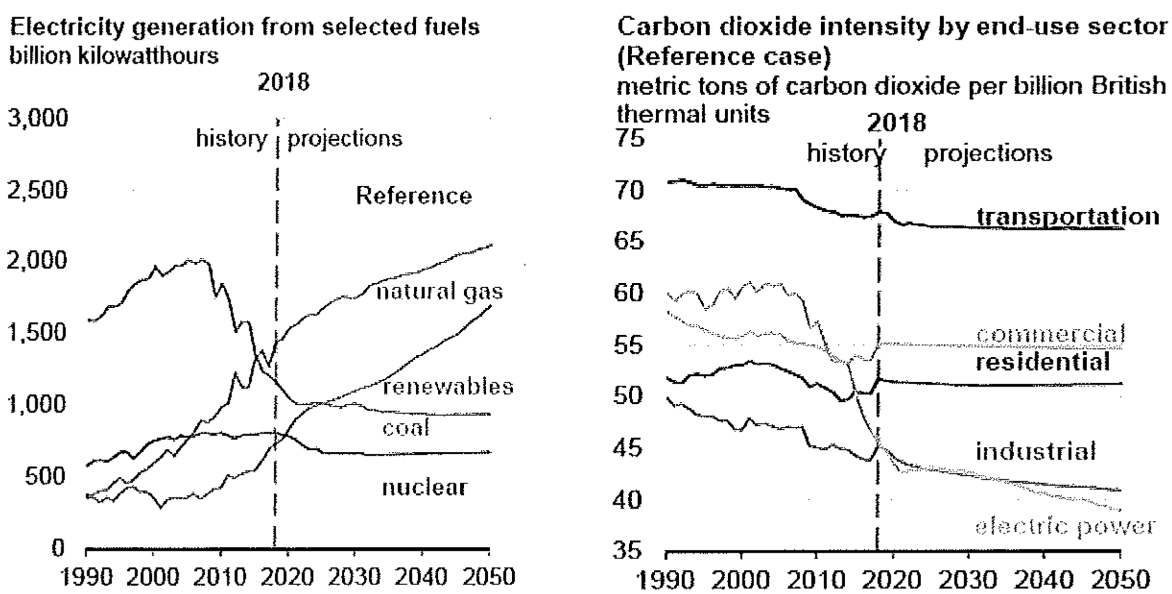


Table 3.5: CO_2 Price Assumptions

	2016 $/Ton Real			Nominal		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2025	$0.00	$3.11	$3.11	$0.00	$3.71	$3.71
2026	$0.00	$3.42	$3.42	$0.00	$4.17	$4.17
2027	$0.00	$3.77	$3.77	$0.00	$4.68	$4.68
2028	$0.00	$4.15	$4.15	$0.00	$5.26	$5.26
2029	$0.00	$4.57	$4.57	$0.00	$5.91	$5.91
2030	$0.00	$5.03	$5.03	$0.00	$6.64	$6.64
2031	$0.00	$5.54	$5.54	$0.00	$7.46	$7.46
2032	$0.00	$6.11	$6.11	$0.00	$8.39	$8.39
2033	$0.00	$6.73	$6.73	$0.00	$9.43	$9.43
2034	$0.00	$7.42	$7.42	$0.00	$10.60	$10.60
2035	$0.00	$8.18	$8.18	$0.00	$11.91	$11.91
2036	$0.00	$9.01	$9.01	$0.00	$13.39	$13.39
2037	$0.00	$9.93	$9.93	$0.00	$15.05	$15.05

It should be noted that the price assumptions shown represent an explicit price on CO_2 emissions, not necessarily an estimated cost to comply with CO_2 emission regulations. While these prices may factor into the cost of compliance, the cost to comply is necessarily a function of the form of the regulation and the compliance options available.

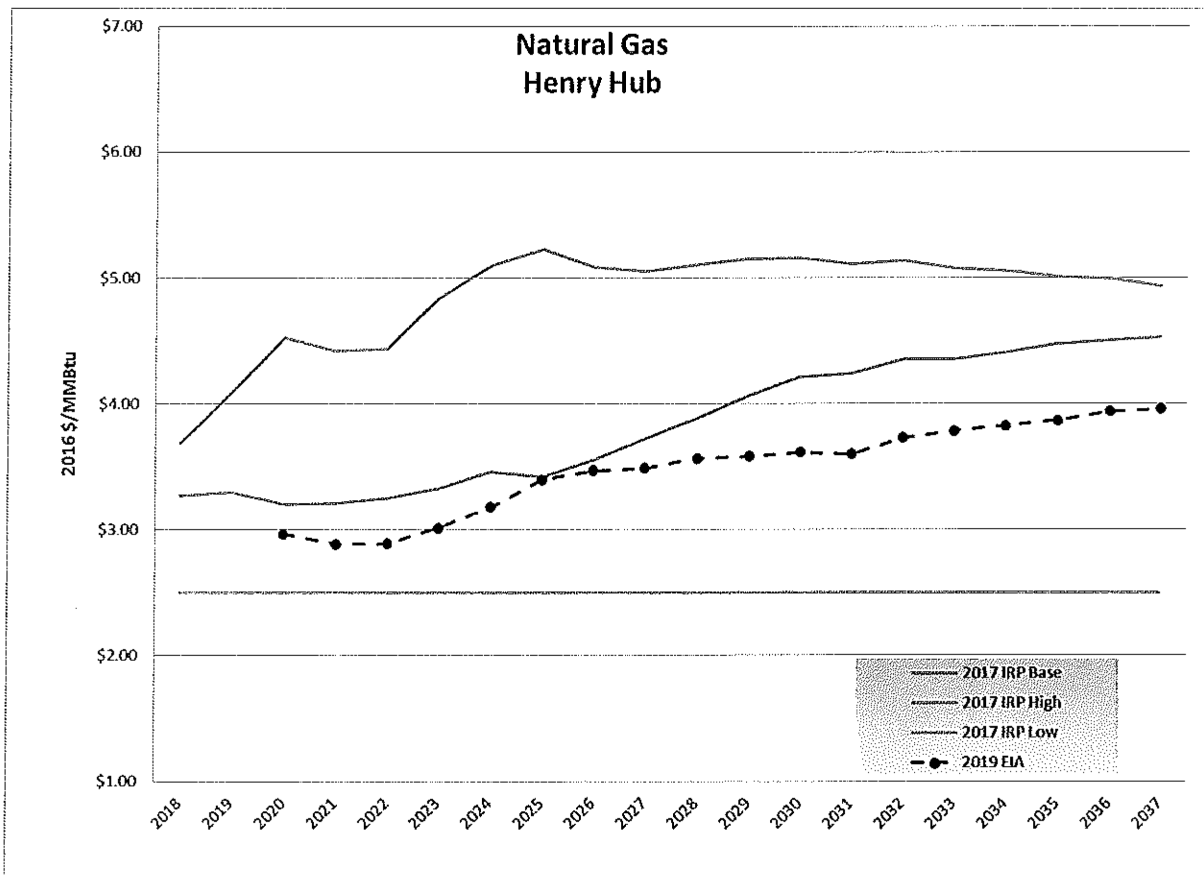
Natural Gas Prices

Supply – According to 2019 AEO, natural gas production from shale gas and tight oil plays as a share of total US natural gas production continues to grow, both in share and absolute volume because of the sheer size of the associated resources. Associated natural gas production from tight oil production in the Permian Basin grows strongly as does the oil co-production from Eagle Ford and Haynesville regions. The continued development of the Marcellus and Utica shale plays in the east are also robust. Technological advancements and improvements in industry practices continue to lower production costs and increase volume of natural gas recovery per well. These advancements have a significant cumulative effect in play that extend over wide areas and that have large undeveloped resources. Our expectations for natural gas supply in the 2017 IRP remain consistent with the current view from AEO 2019.

Demand – In reviewing the drivers of demand, we continue to see several drivers shaping it long term. The drivers are energy efficiency programs, coal to gas switching, industrial growth and LNG exports. Upward pressure on demand will result from expanded coal to gas switching, industrial growth and global exports of LNG with only efficiency having a moderating impact. The 2019 AEO includes an expectation that the United States will remain a net natural gas exporter in all cases due to the robust supply and increasing productivity advances to access this resource.

Infrastructure – The expectations for infrastructure remain consistent with the 2017 IRP. The developments in large gas production in the Marcellus and Utica shale reserves in the Northeast continue to create a dramatic shift in flow. These changes in the interstate pipeline system will occur as the supply pool from the Northeast grows. Natural gas will be directed toward the growing demand from: the petro-chemical industry in the Southeast, gas-fired generation throughout the Midwest and East, and LNG exports in the Gulf Coast.

Figure 3.6: Natural Gas Price Forecasts



Price – Current expectations are for prices to trend closer to the low end of our IRP range. However, as we move forward in time demand from LNG exports, coal-to-gas switching and increased industrial demand could drive higher prices in later years. As demonstrated in Figure 3.6, EIA's 2019 Annual Energy Outlook reflects future gas prices that are well within the range used in the 2017 IRP.

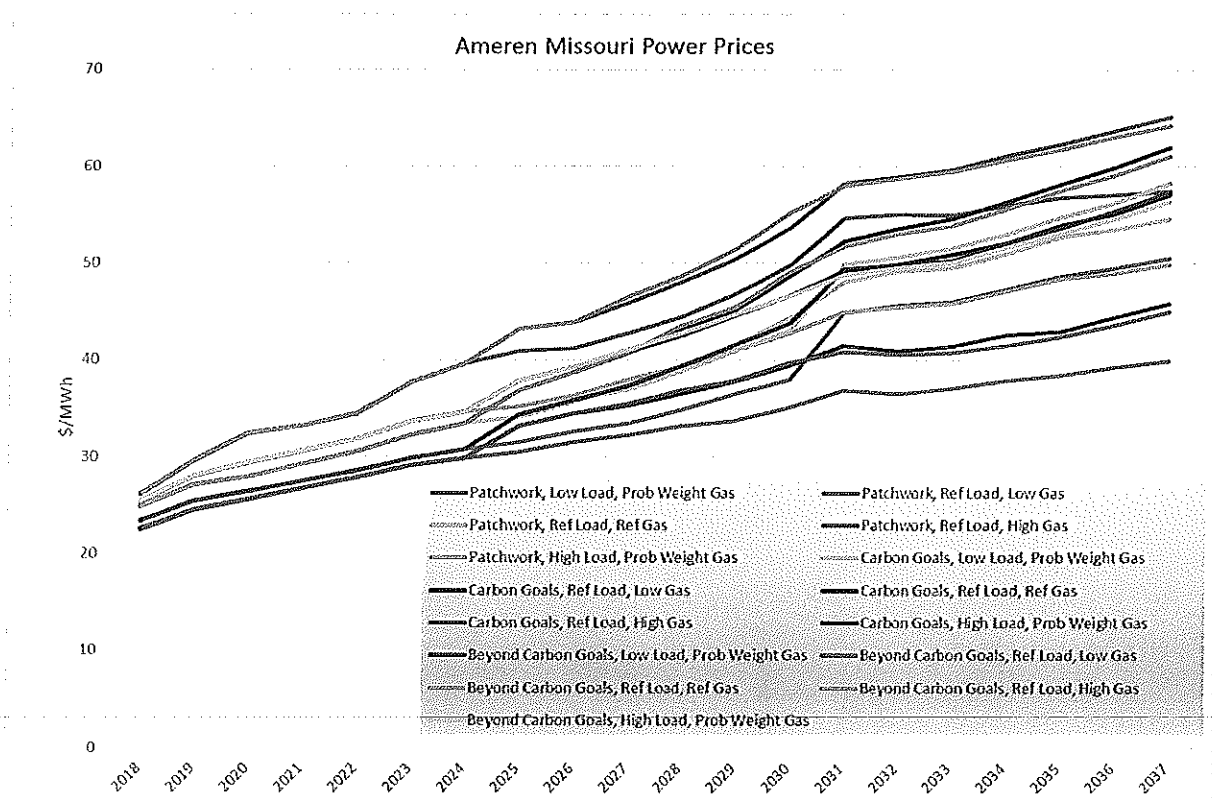
Load Growth

In the probability tree in Figure 3.3, load growth has 3 different value levels – one features a 0.48% compound annual growth rate (CAGR) over the IRP 20-year timeframe, with a 20% subjective probability; the other is -0.37% CAGR over the IRP 20-year timeframe, with a 60% subjective probability; and the last level features -1.36% CAGR with a 20% subjective probability. We continue to use these three levels to represent the distribution of potential load growth based on a review of assumptions with our internal subject matter experts. Our load growth assumptions for Ameren Missouri's service territory continue to fall within this range.

3.5.2 Scenario Modeling

Because current assumptions for each of the three scenario variables described in section 3.3.1 are within the ranges defined in our 2017 IRP, no updated scenario modeling is warranted at this time. The power price forecasts for the scenarios modeled for the 2017 IRP are presented in Figure 3.7 below.

Figure 3.7: Market Price Scenarios



3.5.3 Independent Uncertain Factors

Ameren Missouri reviewed a broad range of uncertain factors, including foreseeable emerging energy efficiency, storage and distributed generation technologies in its 2017 IRP[21] and identified two independent uncertain factors to be critical as a result of the sensitivity analysis conducted and presented in the 2017 IRP: DSM costs and coal prices. The Company reviewed its expectations and previous value ranges for these critical uncertain factors and determined the % deviations for the low-base-high values from the expected values of each uncertain factor are still valid.

3.5.4 Coal Price Forecasts

The 2017 IRP long-term coal price assumptions included a review of the drivers that most affect the coal industry and more specifically those affecting Powder River Basin (PRB) coal. The overall assumptions about US coal supply have not materially changed.

Ameren Missouri continues to maintain an expectation that long-term demand for PRB coal will be negatively affected by lower energy prices and coal-fired power plant retirements. Additionally, how environmental regulations, transportation costs and even producer solvency will influence the coal markets are continually under review.

The factors reviewed that affect PRB production costs remain the same and are:

- Strip ratios (overburden vs. coal seam) are expected to increase.
- Government regulations continue to increase reclamation costs including coal producers potentially having to insure payment of future reclamation costs ("self-insurance" will be more limited in the future).
- Severance taxes and coal lease fees.
- Cost of materials, supplies and capital equipment such as diesel fuel, explosives & haul trucks.
- Haul distances from coal pit to load-out are expected to increase.
- Eventual interference with the railroad mainline.

The cost of mining PRB coal has recently declined and stabilized as producers have reduced operations and focused on more cost-effective reserves to meet the declining demand base. However, long-term production costs are projected to rise as strip ratios increase. Strip ratios are forecasted to increase by 25% over the next 20 years based on current supply and demand fundamentals. Mining companies have reduced cash costs

[21] File No. EO-2019-0065 Paragraph 1.A (1)-(3)

over the past few years but long-run costs will increase in real terms due to the increasing strip ratios as production moves westward.

Coal prices may vary from the forecast due to the drivers mentioned above but are not limited to those drivers alone. Examples of other drivers that may impact coal prices are new mining, generation or environmental technology, changes in the electric grid and load loss/growth.

Our plan to meet emission compliance standards is to continue utilizing environmental controls and burn predominantly ultra-low sulfur coal (typically considered 0.55 lb. SO_2/MMBtu or less) remains consistent with assumptions made in the 2017 IRP. Ameren Missouri expects long-term production/supply of ultra-low sulfur PRB coal to be 200-350 million tons per year.

3.6 Energy and Peak Forecasting[22]

Ameren Missouri has reviewed its key drivers for long-term load expectations and has concluded that current expectations are materially unchanged.

In its 2017 IRP, Ameren Missouri has evaluated the impact of distributed generation and electric vehicles at low-base-high levels of penetration. The analysis can be found in Chapter 3 of the 2017 IRP. Ameren Missouri will be providing $28 Million in solar rebates to customers that install solar systems between 2019 and 2023 as included in Senate Bill 564 and Ameren Missouri Smart Energy Plan. Solar rebates accelerate customer-owned solar installations in the first few years but are not expected to materially change the total installation expectations through the planning horizon.

The Company's current and planned EV-related initiatives focus on the Charge Ahead – EV proposal that was partially approved by the Commission in February, 2019 (File No. ET-2018-0132). The Corridor Subprogram was approved and allows Ameren Missouri to provide incentives to stimulate the private sector to develop, own, and operate approximately 11 DC-fast charging islands in the Company's service territory. This innovative program is designed to jump start the free market in order to leverage private investment in a manner that develops infrastructure that meets EV-owning customers' changing service needs and helps encourage broader EV adoption by customers. The other localized charging station incentives proposed by Ameren were not approved and the Commission has ordered the MoPSC Staff to open a working docket (File No. EW-2019-0229) to further evaluate various options for development of localized EV charging stations.

[22] File No. EO-2019-0065 Paragraph 1.B; File No. EO-2019-0065 Paragraph 1.J

In addition, Ameren Missouri has a commitment that is memorialized in the Stipulation and Agreement in File No. ER-2016-0179 to propose amendments to its existing residential time-of-use rate that, among other objectives, are designed to promote additional off-peak charging of EVs.

The EV landscape is rapidly evolving, and Ameren Missouri continues to monitor emerging technologies, trends, and developments in other jurisdictions. Through these activities, Ameren Missouri will consider on an ongoing basis new beneficial ways to support its customers' adoption and use of EVs. Ameren Missouri is very cognizant of the Court of Appeals Western District decision regarding utility ownership of EV charging equipment and the options that provides to meet customer needs going forward, but has no current plans to change the incentive-based approach to EV charging development proposed in the Charge Ahead proceeding.

4. Compliance References

Appendix A
SMP Financial Analysis[1]

THIS APPENDIX IS CONFIDENTIAL IN ITS ENTIRETY

[1] EO-2019-0065 Paragraph 1.D