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Assessing the Economic Value of New Utility-Scale Electricity Generation Projects

Introduction and motivation

Electricity producers, consumers, and policymakers all desire measures that can provide insight into the economic attractiveness of deploying alternate electricity generation technologies.

Levelized cost of electricity (LCOE), one commonly cited cost measure, reflects both the capital and operating costs of deploying and running new utility-scale generation capacity of any given type. However, as often noted by EIA[1], the direct comparison of LCOE across technologies to determine the economic competitiveness of various generation alternatives is problematic and potentially misleading. Actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other considerations. The projected utilization rate, which depends on the load shape and the existing resource mix in an area where additional capacity may be needed, is one such factor. The existing resource mix in a region can directly affect the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different value than one that would displace existing coal generation. A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, dispatchable technologies generally have more value to a system than non-dispatchable ones, including those whose operation is tied to the availability of an intermittent resource.

A better assessment of the economic competitiveness of a candidate generation project can be gained through joint consideration of its LCOE and its avoided cost, a measure of what it would cost the grid to meet the demand that is otherwise displaced by a new generation project. Avoided cost accounts for both the variation in daily and seasonal electricity demand in the region where a new project is under consideration and the characteristics of the existing generation fleet to which new capacity will be added, thus comparing the prospective new generation resource against the mix of new and existing generation and capacity that it could displace. Avoided costs may be summed over the financial life of a candidate project and converted to a stream of equal annual payments, which may then be divided by average annual output of the resource to develop a levelized avoided cost of electricity (LACE) for the project. Unlike LCOE, the calculation of LACE requires tools to simulate the operation of the project being evaluated within its particular regional power system.

The difference between the LACE and LCOE values for the candidate project provides an indication of whether or not its economic value exceeds its cost, where cost is considered net of the value of any production or investment tax credits provided by federal law. If multiple technologies are available to

[1] See http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm.

meet load, the difference between LACE and LCOE may be calculated for each of them to determine which project provides the highest net economic value.

This paper presents measures of the economic value for three types of power generation projects (onshore wind, solar PV, and advanced combined cycle natural gas generation)[2] across 22 regions within the U.S. electricity system based on the difference between the LACE and LCOE values for each project type in each region. These estimates are derived from input and calculations performed within the National Energy Modeling System (NEMS), and reflect the resource utilization and electric grid characteristics that are projected in the Annual Energy Outlook 2013 (AEO 2013) Reference and No Sunset cases. These calculations of economic value do not reflect the direct value of compliance with Renewable Portfolio Standards (RPS), which are currently in force in 30 states. That is, the payment of Renewable Energy Credits or other RPS compliance revenues are not included.

Main findings

Findings regarding the economic value of candidate generation projects

- **For projects entering service in 2018, the estimated economic value of onshore wind and solar PV projects is negative and significantly below that of advanced combined cycle (Adv CC) projects in all regions (Table 3a). However, the net economic value of onshore wind and solar PV projects improves significantly over the projection period.** By 2035, the economic value of onshore wind is positive in 6 of 20 regions where the technology can be built, and in 3 of 21 regions for solar PV (with 5 additional regions close to breakeven). Improved economics for wind and PV projects over time reflect higher costs to operate existing generation, increased load, and lower LCOE of wind and solar PV due to declining technology costs[3]. In other regions, wind and solar PV projects continue to be unattractive on a net value basis relative to Adv CC projects.
- **If PTC and ITC provisions that are scheduled to sunset under current law are instead assumed to be continued throughout the projection period (No Sunset case), a lower after-tax LCOE raises the net economic value of both onshore wind and solar PV projects.** In 2018, the value of such projects remains negative in all regions even in this case (Table 3a). However, for capacity entering service in 2035 wind projects have a positive net economic value in all but 2 of 20 regions, while solar projects have a positive net economic value in 13 of 21 regions and are close to breakeven in another 5 regions.
- **For the Adv CC technology, the difference between LACE and LCOE varies less across regions and improves far more slowly over time compared to both wind and PV technologies (Table 3a). In 2018, there is little demand for new capacity and Adv CC units do not have a positive net economic value in any region. By 2035, growth in demand for new capacity results in a positive net economic value in 9 of 22 regions, with most of the remaining regions showing near-breakeven conditions for Adv CC**.

[2] See http://www.eia.gov/forecasts/capitalcost/ for a more complete description of the technologies and their underlying cost characteristics.

[3] Wind is assumed to not be available in Florida because of the lack of suitable, high-quality wind resources. In New York City, wind cannot be built for lack of significant undeveloped land on which to site a utility-scale wind plant.

- If the Federal tax credits for wind and solar are extended indefinitely, the estimated LACE of a candidate Adv CC project entering service in 2035 is reduced due to additional generation from wind and solar PV capacity with lower variable costs. In this scenario, Adv CC projects have a positive net economic value in 6 regions and significantly negative values in 8 regions.

- **Direct comparison of LCOE values significantly understate the advantage of the Adv CC relative to onshore wind in terms of economic value in all regions, while overstating the advantage of Adv CC relative to solar PV (Tables 1a and 3a).**
- Once a technology achieves a net positive economic value (a similar concept to "grid parity"), its net economic value often hovers close to zero in a model run that adds generation to meet load.
  - The market, as represented in the NEMS model, tends to develop any given resource just to the point where the net economic value of most attractive marginal capacity addition is close to breakeven after having met load growth and/or displaced higher cost generation.
  - Market shocks, such as the entry of a new technology, change in policy, or sudden change in underlying cost of fuels or technologies may cause a divergence between LACE and LCOE. Increases in a technology's net value will soon revert to zero as the technology gets built in response. If the net value is pushed to be negative, the value may recover with load growth or other market developments.

Findings regarding LACE estimates

- **LACE estimates (Tables 2a and 2b) show significantly more variation across regions than LCOE estimates (Tables 1a and 1b). LACE values are sensitive to the underlying generation mix and fuel cost structure within each region, as well as the regional load shape and projected regional demand growth**. All else equal, LACE estimates are higher in regions where demand growth requires that some type of new capacity be added. In regions that do not require near-term capacity additions, avoided costs largely reflect fuel cost savings, with very little value attributable to the availability of additional capacity.
- **All else equal, LACE for all technologies increases with the fuel costs associated with running existing generation units whose use would be reduced by a new project**. Because the prices of both natural gas and coal used to fuel existing power projects subject to displacement are projected to rise over time, projected LACE values also rise over time.
- **There are systematic differences in LACE values across technologies (Tables 2a and 2b).**
  - PV projects, which tend to generate power during peak demand periods, have a higher LACE value than wind or Adv CC projects in nearly all regions.
  - Onshore wind projects, whose output is generally poorly matched with peak loads on both a seasonal and diurnal basis, tend to have a lower LACE than PV or Adv CC projects.

Findings regarding LCOE estimates

- **LCOE[4] estimates for all three technologies vary across the 22 NEMS regions, but the LCOE values for solar PV and onshore wind projects show more regional variation than those for Adv CC**

[4] Values for LCOE reported in this paper may differ from those reported at http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm. The values in this report include Federal tax subsidies for

projects (Tables 1a and 1b). The greater variation in LCOE across regions for solar PV and wind projects reflects the variation in the availability of these intermittent resources.

- **LCOE values for solar PV and onshore wind projects are sensitive to the continued availability of production tax credit (PTC) for wind and the 30 percent investment tax credit (ITC) for solar PV (Tables 1a and 1b).** Under laws and regulations as of the date of this report, the PTC for wind is available for plants that commence construction prior to the end of 2013. The 30 percent ITC for PV is available for capacity that enters service by the end of 2016, while capacity entering service after 2016 is eligible for a 10 percent ITC.
- **While the LCOE for wind and solar projects generally declines over time as technologies advance, the outlook for future natural gas prices, which rises in EIA's Reference case projections, results in a projected rise of the LCOE of Adv CC projects over time**.

Caveats and Limitations

- The value of state RPS programs on wind and PV generation (which do not directly affect LCOE) will only be reflected in the LACE to the extent that resources not eligible for the RPS establish the marginal cost of system energy during hourly, daily, and seasonal period in which the technology being evaluated is generating power.[5] As discussed in the body of the paper, the potential under-valuation of excluding the value of Renewable Energy Credits (RECs) is likely much smaller than the almost certain over-valuation that would occur by incorporating the REC values into the calculation of net economic value.
- The analysis in this paper was conducted with a 22-region model of the U.S. electricity system. Resource characteristics reflect average values for each region, and do not reflect characteristics at specific locations, especially in large, geographically diverse regions. For example, the solar resource likely varies widely across the Northwest region, which includes both Nevada and Washington state, but the model reflects only an average value.
- The LCOE and LACE estimates presented in this paper provide some insight into model projections developed using NEMS and the gross economics underlying the projection, but they do not fully capture the range of evaluation criteria used in either the model or in the real world for capacity planning decisions.

Estimates of LCOE and LACE at the regional level

Table 1a shows the LCOE estimates for photovoltaic (PV), wind, and advanced natural gas combined cycle technologies across 22 electricity market regions used in NEMS (see Appendix A for a regional map) for the Reference case for service entry years 2018 and 2035.

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renewable generation – consistent with the policy assumptions of the case under examination – to facilitate comparison with LACE. The values at the link above exclude power-sector subsidies.

[5] Arguably, the RPS-value of an eligible technology could be accounted for by subtracting the prevailing "REC" (renewable energy credit) price from the technology's LCOE. However, because this value is, in all likelihood, at least partially picked-up in the LACE calculation, this would lead to near certain over-valuing of the resource in question. By leaving the REC out of the equation, it is possible that the resource is under-valued, but for the most part, it is reasonable to assume that in most regions during most hours of the year that a non-eligible resource such as natural gas or coal is setting the system marginal value for electricity. Therefore the potential under-valuation of excluding the REC is likely much smaller than the almost certain over-valuation that would occur by incorporating the REC into the calculation of net economic value.

TABLE 1a: Reference case LCOE* ($ per megawatthour)

Technology/Fuel	Solar PV w/10% ITC		Wind		Advanced CC	
Year Entering Service	2018	2035	2018	2035	2018	2035
Region**						
1 Texas	108	92	89	79	61	78
2 Florida	117	99	N/A	N/A	69	86
3 Eastern Wisconsin	146	123	100	88	60	78
4 Northern Plains	129	109	74	71	64	82
5 New England	153	130	83	83	66	81
6 New York City	N/A	N/A	N/A	N/A	74	87
7 Long Island	204	171	88	87	74	87
8 Upstate New York	147	124	95	84	66	80
9 Mid Atlantic	149	126	97	86	65	80
10 Lower Michigan	145	122	93	82	61	78
11 Great Lakes	150	127	94	84	61	79
12 Mississippi Delta	124	105	79	80	61	78
13 Mississippi Basin	145	122	96	85	66	83
14 Alabama/Georgia	119	101	90	80	63	81
15 Tennessee Valley	126	107	79	80	64	84
16 Virginia Carolina	112	95	78	79	65	83
17 Central Plains	119	101	73	70	65	82
18 Southern Plains	118	100	83	73	62	79
19 Arizona/New Mexico	102	87	82	72	68	82
20 California	117	99	91	87	76	93
21 Northwest	121	102	82	73	64	86
22 Rocky Mountain	108	92	81	72	68	83

**- Values for LCOE reported in this paper may differ from those reported at www.eia.gov/forecasts/aeo/er/electricity_generation.cfm. The values in this report include Federal tax subsidies for renewable generation – consistent with the policy assumptions of the case under examination – to facilitate comparison with LACE. The values at the link above exclude power-sector subsidies.*
***- Region names are intended to be approximately descriptive of region location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions. Appendix A contains a map of regions along with formal EIA names for the regions based on boundaries and names established by the North American Electric Reliability Council (NERC).*
N/A – Resource not available for utility-scale installation in region.
Source: AEO 2013, Reference Case

LCOE for all three types of projects varies across NEMS regions, but the values for solar PV and onshore wind projects show more regional variation than do combined cycle natural gas projects, reflecting the variation in the resource quality throughout the United States.

While natural gas prices also show some inter-regional variability, the variation in annual output of the intermittent resources across regions tends to have the larger impact on LCOE. PV LCOE shown in Table 1a includes the 10-percent ITC currently embedded as a permanent provision of U.S. tax law[6].

LCOE values for solar PV and onshore wind projects are sensitive to the continued availability of the current PTC for wind and the 30-percent ITC for solar PV beyond their current sunset dates[7]. Table 1b, summarizes regional LCOE values in the AEO2013 No Sunset case, which assumes extension of both the PTC and the 30-percent ITC through the end of the projection period.

As shown in the table, continuation of the 30-percent ITC reduces the LCOE of PV compared to the Table 1a values by $30 to more than $60 per megawatt-hour (MWh) across regions for plants entering service in 2018. Continuation of the PTC reduces the wind LCOE by roughly $20/MWh. This results from both the direct value of the subsidy as well as indirect impacts from different technology build-out patterns across the two sets of projections.

Although Adv CC units fueled by natural gas do not receive expiring tax credits that are continued in the No Sunset case, LCOE for advanced CC units is modestly lower than in the Reference case, as natural gas fuel costs are somewhat lower due to the lower demand for natural gas in an electric power sector that makes greater use of both wind and solar PV.

Shifting from LCOE to LACE, Table 2a shows the LACE estimates for PV, wind, and advanced CC technologies across the 22 electricity market regions used in NEMS in the Reference case for service entry years 2018 and 2035.

LACE varies across regions within a given year and through time. While there are some common factors affecting both LACE and LCOE, LACE is determined by the interactions among all of the plants in a given region, while LCOE is strongly dependent on the characteristics of the individual technology being evaluated.

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[6] This differs from the treatment of the permanent 10-percent ITC in other EIA published LCOE estimates, which do not include direct electric power subsidies, and is done to facilitate the comparison of cost, as seen in the market, with value as seen by the market.

[7] The AEO 2013 Reference case was completed prior to the 1-year extension and deadline redefinition of the PTC for wind and other renewable projects, and for this case, and end-of-year 2012 expiration is assumed.

TABLE 1b: No Sunset case LCOE ($ per megawatt-hour)

Technology/Fuel	Solar PV w/30% ITC		Wind w/PTC		Advanced CC	
Year Entering Service	**2018**	**2035**	**2018**	**2035**	**2018**	**2035**
Region						
1 Texas	87	70	68	57	60	73
2 Florida	94	76	N/A	N/A	69	84
3 Eastern Wisconsin	117	94	78	65	60	73
4 Northern Plains	104	83	53	49	63	74
5 New England	123	99	65	62	66	76
6 New York City	N/A	N/A	N/A	N/A	73	82
7 Long Island	162	130	77	64	73	82
8 Upstate New York	118	95	73	62	65	75
9 Mid Atlantic	120	96	75	63	65	76
10 Lower Michigan	116	93	71	66	60	74
11 Great Lakes	120	97	73	61	60	74
12 Mississippi Delta	100	80	69	57	61	74
13 Mississippi Basin	116	93	74	62	65	78
14 Alabama/Georgia	96	77	68	57	63	76
15 Tennessee Valley	101	82	63	100	64	79
16 Virginia Carolina	90	73	67	86	64	77
17 Central Plains	95	77	58	52	64	77
18 Southern Plains	95	76	61	56	61	74
19 Arizona/New Mexico	82	67	60	53	67	76
20 California	93	75	81	68	76	87
21 Northwest	97	78	61	54	63	77
22 Rocky Mountain	87	71	60	53	67	76

N/A – Resource not available for utility-scale installation in region.
Source: AEO 2013, No Sunset Case

For example, LACE tends to be higher in regions with a capacity mix that uses higher-cost fuel in relatively low efficiency plants, as a new project in such a region would displace existing generation from units that are expensive to run.

Load growth within a region also tends to increase LACE. With growing load, any given project is likely to be competing against other new capacity, displacing a portion of the cost of that capacity[8] and its generation. In a region where a new project would primarily displace generation from existing capacity, the cost of which has already been incurred, its economic value comes primarily from displacing the only the variable (primarily fuel) cost of the incumbent generators.

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[8] Wind and solar are assumed not to receive a full "capacity credit" and thus do not displace alternative capacity resources on a one-to-one basis.

TABLE 2a: Reference case LACE ($ per megawatt-hour)

Technology/Fuel	Solar PV w/10% ITC		Wind		Advanced CC	
Year Entering Service	2018	2035	2018	2035	2018	2035
Region						
1 Texas	71	89	54	73	59	79
2 Florida	78	94	N/A	N/A	68	87
3 Eastern Wisconsin	51	89	50	76	50	78
4 Northern Plains	61	96	53	75	56	82
5 New England	66	94	56	77	59	82
6 New York City	N/A	N/A	N/A	N/A	67	89
7 Long Island	66	97	59	81	62	88
8 Upstate New York	67	99	54	74	58	82
9 Mid Atlantic	80	94	54	73	64	81
10 Lower Michigan	71	92	56	74	60	78
11 Great Lakes	74	96	53	71	60	79
12 Mississippi Delta	51	86	51	72	51	78
13 Mississippi Basin	59	95	49	73	53	80
14 Alabama/Georgia	70	90	53	74	59	81
15 Tennessee Valley	74	97	53	76	60	84
16 Virginia Carolina	79	94	57	76	64	83
17 Central Plains	61	95	53	76	55	82
18 Southern Plains	60	89	52	74	55	80
19 Arizona/New Mexico	76	89	58	75	67	84
20 California	70	102	60	86	63	92
21 Northwest	54	99	60	78	64	87
22 Rocky Mountain	78	94	57	76	68	85

N/A – Resource not available for utility-scale installation in region.
Source: AEO 2013, Reference Case

As shown in Table 2a, LACE for all technologies rises over time, reflecting both the projected rising cost of fueling existing capacity and the impact of load growth. PV has a higher LACE than wind, as it tends to displace higher-cost electricity generated during the mid-day/mid-summer peak load periods, and may also obtain additional value from displacing capacity during this peak period. LACE for advanced CC units generally falls between the LACE levels of PV and wind.

As shown in Table 2b, LACE values for the No Sunset case, which assumes indefinite extension of the PTC for wind and the 30-percent ITC for PV, are generally lower than the Reference case LACE values presented in Table 2a for all technologies. The reduction in LACE, which is larger in 2035 than 2018, results from the increased penetration of PV and wind in some regions. The additional penetration of renewable generation tends to reduce LACE through its impact on natural gas prices and changes to the dispatch stack. As less natural gas is used, there is less pressure on the natural gas supply and somewhat lower natural gas prices. In regions where wind and solar are built, this low-dispatch-cost generation leads to the displacement of the highest-cost alternative generation, typically inefficient natural gas or coal generation, leaving only lower-cost resources available for further displacement.

TABLE 2b: No Sunset case LACE ($ per megawatt-hour)

Technology/Fuel	Solar PV w/ 30% ITC		Wind w/PTC		Advanced CC	
Year Entering Service	**2018**	**2035**	**2018**	**2035**	**2018**	**2035**
Region						
1 Texas	67	84	52	68	57	74
2 Florida	78	91	N/A	N/A	68	84
3 Eastern Wisconsin	52	86	51	70	51	73
4 Northern Plains	61	85	51	59	54	67
5 New England	62	90	55	72	57	78
6 New York City	N/A	N/A	N/A	N/A	65	84
7 Long Island	62	93	58	76	60	83
8 Upstate New York	70	93	55	70	59	77
9 Mid Atlantic	79	91	54	68	64	76
10 Lower Michigan	68	84	56	70	60	74
11 Great Lakes	71	93	52	67	58	75
12 Mississippi Delta	51	83	50	67	50	74
13 Mississippi Basin	54	93	48	68	50	76
14 Alabama/Georgia	69	88	52	69	59	77
15 Tennessee Valley	65	92	52	71	56	78
16 Virginia Carolina	78	88	57	70	63	78
17 Central Plains	52	88	50	65	50	72
18 Southern Plains	58	86	52	67	54	75
19 Arizona/New Mexico	73	78	57	64	65	73
20 California	63	89	59	77	60	81
21 Northwest	52	90	57	67	62	76
22 Rocky Mountain	76	84	56	64	66	75

N/A – Resource not available for utility-scale installation in region.
Source: AEO 2013, Reference Case

Table 3a looks at the difference between the LACE and LCOE results for the Reference case to provide an indicator of the economic value of each of the 3 project types at the margin for the 2018 and 2035 service entry dates. If LACE is smaller than LCOE, the resource costs more than the combination of resources that would otherwise serve load. Under such conditions, the new resource would generally not be built. However, if the difference between LACE and LCOE is positive, the resource should be attractive as a new build, since its economic value exceeds its cost. As shown in Table 3a, LCOE exceeds LACE for wind projects entering service in 2018 in all regions, indicating the absence of an economic incentive to build additional wind capacity. With modest natural gas prices and a surplus of generating capacity relative to current load, wind would be displacing low-cost incumbent sources like coal and natural gas generation from combined cycle units.

TABLE 3a: Difference between LACE and LCOE, Reference case ($ per megawatthour)

Year Entering Service	2018			2035		
Technology/Fuel	PV	Wind	Adv. CC	PV	Wind	Adv. CC
Region						
1 Texas	-37	-36	-2	-2	-7	1
2 Florida	-38	N/A	-1	-5	N/A	0
3 Eastern Wisconsin	-95	-50	-10	-34	-13	0
4 Northern Plains	-68	-21	-8	-13	4	0
5 New England	-87	-27	-7	-35	-6	1
6 New York City	N/A	N/A	-7	N/A	N/A	2
7 Long Island	-137	-29	-12	-74	-6	1
8 Upstate New York	-80	-42	-8	-25	-11	2
9 Mid Atlantic	-69	-43	-1	-32	-13	1
10 Lower Michigan	-74	-37	-1	-30	-8	0
11 Great Lakes	-76	-42	-1	-31	-12	0
12 Mississippi Delta	-73	-28	-10	-19	-8	0
13 Mississippi Basin	-86	-46	-13	-27	-12	-3
14 Alabama/Georgia	-49	-37	-4	-11	-6	0
15 Tennessee Valley	-52	-26	-3	-10	-4	0
16 Virginia Carolina	-32	-21	-1	-1	-3	0
17 Central Plains	-58	-21	-10	-6	6	0
18 Southern Plains	-58	-30	-7	-11	1	0
19 Arizona/New Mexico	-26	-24	-1	2	3	2
20 California	-46	-31	-13	3	0	-1
21 Northwest	-67	-23	0	-3	6	1
22 Rocky Mountain	-30	-25	-1	3	4	3

N/A – Resource not available for utility-scale installation in region.
Source: AEO 2013, Reference Case

Table 4a shows how the estimates of the net economic value of the 3 project types considered in Table 3a are reflected in modeled capacity additions. Because the net economic values shown in Table 3a reflects the net economic value of further capacity additions beyond what is added in the model run, a net value near zero may reflect a situation in which capacity additions have occurred or are imminent. To reflect this situation, Table 4a shows capacity additions in the Reference case for each capacity type and region for a 4-year period from the year before to two years after the dates for which the differences between LACE and LCOE are presented in Table 3a. For example, Table 4a shows that there is almost no wind built between 2017 and 2020, consistent with the reported net negative economic value (LACE less LCOE) for this technology in 2018.

For wind projects entering service in 2035, the difference between LACE and LCOE reported in Table 3a narrows in all regions, reflecting both higher LACE and lower LCOE. In 6 of 20 regions[9], LACE exceeds LCOE. The more favorable economics of wind in this timeframe is reflected in greater capacity additions in Table 4a, as wind capacity additions over the 2034 to 2037 period total almost 9 gigawatts (GW) across five of these six regions[10].

The dynamic interaction between LACE and LCOE on the one hand and capacity builds on the other can also be examined with a temporal rather than a geographic cross-section. Looking at the changes in LACE and LCOE over time within a specific region examines in more detail how positive differences between LACE and LCOE tend to drive the market toward an equilibrium condition, that is, the market will tend to seek a long-term situation where avoided costs are at approximate parity with the levelized cost for each technology that is economically viable. Appendix B takes a closer look at these interactions for a specific region of the U.S.

Table 3b provides the same information as Table 3a for the No Sunset case that extends the PTC and ITC as they apply for projects in 2013 throughout the projection period. With the continuation of the PTC through the projection period, the difference between the LACE and the after-tax-credit LCOE for wind projects entering service in 2018 narrows considerably. However, by 2035, the difference between LCOE and LACE is positive in 18 of 20 regions, suggesting that with the PTC, the value of wind exceeds its cost on a widespread basis. In the No Sunset case, national wind capacity additions reported in Table 4b over the 2034 to 2037 period are nearly 25 GW, reflecting the improved value proposition for wind with the PTC.

Solar LCOE remains substantially higher than wind LCOE throughout the projection period, but because of its higher LACE values, the economic attractiveness of PV improves along with that of wind. By 2035 (Table 1a), PV LCOE ranges from about $95 to $190/MWh ($87 to $170/MWh, accounting for the 10-percent ITC), compared to wind, which ranges from $70 to $88/MWh. However, because of the higher LACE for PV, it still has a positive net economic value in 3 of 21 regions[11], with more than 7 GW projected to be built between 2034 and 2037 in the Reference case. If the full 30-percent ITC is extended through the projection period (Table 3b), LACE for PV exceeds the ITC-loaded LCOE in 13 of 21 regions, and nationwide builds over the 2034 to 2037 period increases to over 8 GW.

[9] Utility-scale wind projects are assumed not able to be built in New York City, for lack of suitable land, and in Florida for lack of sufficient, high-quality wind resource.

[10] As previously noted, the LACE and LCOE are not perfect representations of model decision-making criteria.

[11] Utility-scale PV is assumed not able to be built in New York City, for lack of suitable open space. Smaller scale end-use installations could be built in this region, but the cost and value of these installations are significantly different than the utility-scale installations that are the subject of this report.

Table 3b. Difference between LACE and LCOE, No Sunset Case 2018 ($ per megawatthour)

Year Entering Service	2018			2035		
Technology/Fuel	PV	Wind	Adv. CC	PV	Wind	Adv. CC
Region						
1 Texas	-20	-16	-4	14	11	1
2 Florida	-16	N/A	-1	15	N/A	0
3 Eastern Wisconsin	-65	-27	-9	-8	5	-1
4 Northern Plains	-43	-2	-10	2	10	-7
5 New England	-61	-10	-9	-9	9	1
6 New York City	N/A	N/A	-8	N/A	N/A	2
7 Long Island	-100	-19	-14	-37	11	1
8 Upstate New York	-48	-19	-6	-3	9	2
9 Mid Atlantic	-41	-21	-2	-5	5	1
10 Lower Michigan	-48	-15	-1	-9	4	0
11 Great Lakes	-50	-21	-3	-4	6	0
12 Mississippi Delta	-49	-19	-10	3	9	0
13 Mississippi Basin	-62	-26	-15	-1	6	-1
14 Alabama/Georgia	-26	-16	-4	10	12	0
15 Tennessee Valley	-37	-11	-7	10	-29	0
16 Virginia Carolina	-12	-10	-1	15	-16	0
17 Central Plains	-44	-8	-14	11	13	-4
18 Southern Plains	-36	-10	-7	10	11	0
19 Arizona/New Mexico	-9	-3	-2	12	11	-3
20 California	-31	-23	-16	13	9	-5
21 Northwest	-45	-3	-1	12	13	-1
22 Rocky Mountain	-11	-4	-1	13	11	-2

N/A – Resource not available for utility-scale installation in region.
Source: AEO 2013, Reference Case

The difference between LACE and LCOE also varies over time and across regions for Adv CC units. For projects entering service in 2018 (Table 3a), the differences are negative in all but one region (which has approximately equal LACE and LCOE). As shown in Table 4a, projected Adv CC additions over the 2017 to 2020 period total just under 900 MW in the AEO 2013 Reference case. For an incremental candidate project entering service in 2035, there is a very tight range in the LACE to LCOE margin of plus or minus $3/MWh, with half of the regions showing a zero difference. However, with 9 of 22 regions showing positive estimated differences, national Adv CC capacity is projected to increase by almost 18 GW over the 2034 to 2037 period (Table 4a). If tax incentives are extended to the PV and wind options through 2035, as is assumed in the No Sunset case, the LACE for adv CC units is reduced, as there is more low-variable-cost generation in the system. As a result, advanced CC units have a positive net economic value in only 6 regions by 2035 (Table 3b), and new builds over the 2034 to 2037 period are reduced to just under 11GW (Table 4b).

Table 4a. Incremental Capacity Additions by Region, Reference Case (gigawatts)

Year	2017 through 2020			2034 through 2037		
Technology/Resource	PV	Wind	Adv CC	PV	Wind	Adv CC
Region						
1-Texas	0.0	0.0	0.13	0.10	0.0	2.10
2-Florida	0.0	0.0	0.0	0.09	0.0	1.29
3-Eastern Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0
4-Northern Plains	0.0	0.0	0.0	0.0	2.31	0.0
5-New England	0.0	0.0	0.0	0.0	0.63	0.21
6-New York City	0.0	0.0	0.0	0.0	0.0	0.25
7-Long Island	0.0	0.0	0.0	0.0	0.0	0.06
8-Upstate New York	0.0	0.0	0.0	0.0	0.0	0.33
9-Mid Atlantic	0.0	0.0	0.13	0.0	0.0	2.22
10-Lower Michigan	0.0	0.0	0.0	0.0	0.0	0.19
11-Great Lakes	0.0	0.0	0.0	0.0	0.0	0.25
12-Mississippi Delta	0.0	0.0	0.0	0.0	0.0	2.69
13-Mississippi Basin	0.0	0.0	0.0	0.0	0.0	0.0
14-Alabama/Georgia	0.0	0.0	0.0	0.0	0.0	2.87
15-Tennessee Valley	0.0	0.0	0.0	0.02	0.0	0.37
16-Virginia Carolina	0.0	0.0	0.24	1.86	0.0	2.51
17-Central Plains	0.0	0.0	0.0	0.0	3.91	0.0
18-Southern Plains	0.0	0.0	0.0	0.03	0.0	1.11
19-Arizona/New Mexico	0.0	0.0	0.0	1.53	0.89	0.45
20-California	0.06	0.05	0.0	3.00	1.13	0.31
21-Northwest	0.0	0.69	0.34	0.0	1.03	0.50
22-Rocky Mountain	0.0	0.01	0.05	0.48	0.01	0.16

Source: AEO 2013, Reference Case

Once a technology achieves economic competitiveness – defined here as a positive difference between LACE and LCOE – it is difficult to increase this competitive margin. This can be seen most clearly in Tables 3a and 3b with the advanced CC technology. A positive margin indicates an economic driver within that region to build the technology, and the tendency will be to build it until the margin is reduced to zero, as any residual positive margin suggests that system value is being left untapped. Builds will continue until a zero margin is achieved and there is no value left to capture. In some cases, such with the advent of a new technology or other factors external to the electricity market, a shock may occur that causes a sudden change in the net economic value of a given technology, either making it significantly more valuable or less valuable than its own cost. As noted, a strongly positive LACE difference over LCOE tends not to last long as the market will build-out to capture the implied economic rents. A strongly negative LACE difference over LCOE may persist, but factors such as load growth, technology improvements, and any longer-term trends toward increasing fuel prices will tend to gradually erode this negative difference as well.

Table 4b. Incremental Capacity Additions by Region, No Sunset Case (gigwatts)

Year	2017 Through 2020			2034 Through 2037		
Technology/Resource	PV	Wind	Adv. CC	PV	Wind	Adv. CC
Region						
1-Texas	0.0	0.0	0.46	0.0	6.38	1.43
2-Florida	0.0	0.0	0.0	3.74	0.0	0.74
3-Eastern Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0
4-Northern Plains	0.0	0.0	0.0	0.0	3.72	0.0
5-New England	0.0	0.0	0.0	0.0	0.37	0.16
6-New York City	0.0	0.0	0.0	0.0	0.0	0.16
7-Long Island	0.0	0.0	0.0	0.0	0.21	0.10
8-Upstate New York	0.0	0.0	0.0	0.0	0.0	0.18
9-Mid Atlantic	0.0	0.0	0.25	0.0	0.0	2.32
10-Lower Michigan	0.0	0.0	0.0	0.0	0.0	0.0
11-Great Lakes	0.0	0.0	0.0	0.0	0.0	0.46
12-Mississippi Delta	0.0	0.0	0.0	0.0	0.27	1.00
13-Mississippi Basin	0.0	0.0	0.0	0.0	0.0	0.0
14-Alabama/Georgia	0.0	0.0	0.0	0.0	0.07	1.49
15-Tennessee Valley	0.0	0.0	0.0	0.0	0.0	0.23
16-Virginia Carolina	0.02	0.0	0.21	1.89	4.30	2.02
17-Central Plains	0.0	0.0	0.0	0.0	1.36	0.0
18-Southern Plains	0.0	0.0	0.0	0.0	3.17	0.07
19-Arizona/New Mexico	0.0	0.0	0.0	0.0	1.02	0.18
20-California	0.0	0.0	0.0	2.40	1.58	0.0
21-Northwest	0.0	0.0	0.0	0.0	2.40	0.11
22-Rocky Mountain	0.0	0.0	0.14	0.0	1.50	0.10

Source: AEO 2013, Reference Case

Caveats and Limitations

As previously noted, both LACE and LCOE are estimated based on factors derived from the National Energy Modeling System (NEMS) for the cases indicated. NEMS incorporates a 22-region model of the U.S. electricity system. Resource characteristics reflect average values for each region, and may not reflect characteristics at all locations, especially in large, geographically diverse regions. For example, the solar resource likely varies widely across the Northwest region, which includes both Nevada and Washington, but the model reflects only an average value.

The LACE and LCOE estimates presented in this make certain simplifying assumptions and thus are not fully representative of the calculations used within NEMS to evaluate capacity expansion decisions, and may not perfectly correlate with capacity expansion projections in the runs indicated. Factors such as the "market sharing algorithm" contained within NEMS may slightly alter the particular comparisons indicated in the LACE and LCOE values presented here.

While direct subsidies, such as Federal tax credits, do flow through to the estimates of LCOE (and do not directly affect the LACE calculation)[12], the value of state RPS programs on wind and PV generation (which do not directly affect LCOE) will only be reflected in the LACE to the extent that resources not eligible for the RPS establish the marginal cost of system energy in the portions of the year that the technology being evaluated operates in.[13]

Furthermore, the NEMS model itself is an imperfect representation of the capacity expansion market at any given place and time. Factors such as technology cost and performance, financing, and system configuration are represented by approximations that collapse local, regional, technological, and temporal variation in these factors to facilitate computational tractability and efficiency of the model. The particular values found in this report may be useful for obtaining a better understanding of the projections that EIA produces as part of the AEO and related reports and in gaining a general understanding of a broad sampling of the market. Evaluation of a particular project or a technology under specific circumstances that differ from those assumed in these cases would require estimating LCOE and LACE values specific to those circumstances. Application of the particular values used in the report for either LCOE or LACE outside of the context for which they were originally developed could produce substantially misleading results.

Finally, unless otherwise noted (as in the No Sunset case described in this report), the cases used in this report assume the implementation of current laws and policies. In addition to the treatment of the Federal tax credits for wind and PV as previously noted, these cases do not assume an explicit value for carbon emission reductions or a national requirement for renewable or other clean energy resources (such as a national renewable portfolio standard or clean energy standard), although state programs such as these are represented to the extent possible within the NEMS framework. Environmental regulations that affect the electric power sector are represented as they were in place during late 2012, and do not account for any subsequent judicial or regulatory rulings that may have been issued. The No Sunset case does assume extension of certain Federal tax credits for renewable generation and energy efficiency technologies, but assumptions are otherwise the same as in the Reference case.

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[12] That is, the subsidies aren't directly additive to or subtractive from the LACE of subsidized technologies as they are with the LCOE. The subsidy value may indirectly affect the LACE for the subsidized or any other technology, for example by modifying the dispatch stack to produce a lower marginal cost of electricity over a portion of the year that then would be incorporated into the estimates for LACE for all technologies operating in that portion of the year.

[13] Arguably, the RPS-value of an eligible technology could be accounted for by subtracting the prevailing "REC" (renewable energy credit) price from the technology's LCOE. However, because this value is, in all likelihood, at least partially picked-up in the LACE calculation, this would lead to near certain over-valuing of the resource in question. By leaving the REC out of the equation, it is possible that the resource is under-valued, but for the most part, it is reasonable to assume that in most regions during most hours of the year that a non-eligible resource such as natural gas or coal is setting the system marginal value for electricity. Therefore the potential under-valuation of excluding the REC is likely much smaller than the almost certain over-valuation that would occur by incorporating the REC into the calculation of net economic value.