Estimating the Impact of Residual Value for Electricity Generation Plants on Capital Recovery, Levelized Cost of Energy, and Cost to Consumers

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List of Acronyms

BNEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CRF	capital recovery factor
CT	combustion turbine
DCF	discounted cash flow
EIA	U.S. Energy Information Administration
FOV	follow-on value
ITC	investment tax credit
LCOE	levelized cost of energy
MACRS	Modified Accelerated Cost Recovery System
MWt	megawatts thermal
NG	natural gas
NPV	net present value
O&M	operations and maintenance
PPA	power-purchase agreement
PV	photovoltaic(s)
RoE	return on equity
RoR	rate of return
RV	residual value
WACC	weighted average cost of capital

Executive Summary

Financial analyses that do not capture the full value across the entire lifetime of an electric-generating asset may undervalue the asset. When the asset is new, its electric generation is often contracted to be sold for a specified period at a predetermined rate. This fixed *contracted life* is associated with the *contracted value* of net earnings during this period. However, generating assets typically have a longer *financial life* over which investors are expected to recover capital and earn returns. Between the end of the contracted life and the end of the financial life, the asset produces a *residual value* (RV) of net earnings. Finally, an asset's *actual operating life* can be even longer than its financial life—often owing to improvements made to the asset later in its life—in which case it produces a *follow-on value* (FOV) of net earnings during the period following the end of its financial life.[1]

At the time of the decision to invest in a generating asset, the RV and FOV are uncertain, yet these values can be substantial. Including RV in projected finances can affect the asset's economics more than changes to the fuel price, utilization, and rates of return, depending on the technology and contract length. FOV has two main potential benefits and sources of present value. First, increased system life allows assets to generate additional positive cash flows over a longer period. Second, because the decision to make follow-on investment often occurs well into a generating asset's life, the asset owner retains an *option* to extend the lifetime when it is economically beneficial to do so. Although the uncertainty surrounding the lifetime of different technologies and future energy values makes the present FOV uncertain, the future option to choose to extend asset life and possibly increase the capacity under favorable conditions—or not to under less favorable conditions—offers the potential for added value with little downside risk.

In this report, we explore the opportunities and risks associated with the RV and FOV of electricity generators. To illustrate the value of RV, we assume a contract period of 20 years and an RV period of 10 years, although these parameters could vary substantially in practice. We discuss the RV and FOV phases in the context of discounted cash flow that results in the levelized cost of energy (LCOE) metric used in technology benchmarking. Also, the data enable a discussion of fixed contracts, such as power-purchase agreements (PPAs), used in electricity markets and grid modeling. We also consider the potential application of RV and FOV, which have historically provided value to thermal plants, to wind and solar generation technologies, in the context that most of these renewable assets are still operating under their original electricity contracts, given how recently they were installed.

The report includes the following findings:

- **The realized operational lives of generation technologies before retirement are typically much longer than typical measures of financial lives.** Typical PPA contracts, expectations of capital recovery, and even estimates of likely operational lives of conventional generation assets have often been shorter than their historical operational lives, many of which are 50 years of age or more. Additionally, based on decades of study and operational experience, the

[1] Although the distinction between RV and FOV is inherently arbitrary, for the purposes of this report, we consider RV to be the period over which operations are expected with relatively normal operating expenses and FOV to be the period during which it is necessary to make significant strategic decisions about continuing to operate. RV may include a negative component for decommissioning at point of retirement net any salvage value.

plant lifetimes for solar photovoltaics (PV) and wind are in the range of 25 to 35 years, but total lifetimes are viewed as less certain than the lifetimes of conventional thermal and hydropower electric generation technologies.

- **Including an RV estimate in investor returns can reduce initial electricity prices such that electricity sold by a new generation asset is more competitive in the near term.** Figure ES-1 (next page) shows that the impact of RV on lowering LCOE can be comparable to the impact of other factors considered in generation investment decisions. Including RV for certain technologies may also help provide a more complete and accurate assessment across all technology options.
- **Refurbishment has a useful and economic role but is often neglected during initial investment.** Extending the life of thermal or hydroelectric generation assets typically requires minor or major upgrades, but the cost of such extensions—which may include increased nameplate capacity—has often been more attractive on a present-value basis than the alternative of complete replacement with the same technology or a different technology. Therefore, investing in technologies with the ability to be refurbished or upgraded provides the value of the option to do so. Similar considerations may increasingly apply to both PV and wind in the future.
- **Increasing RV through life extension without refurbishment has an LCOE impact.** If the operational lifetime is extended—for example, from 20 to 30 years, or from 30 to 40 years—the difference in LCOE represents an increase in present value, and it may lower the price of energy over any given period.[2] This suggests that research and development as well as commercial efforts to extend the life of wind or PV, as well as most generation technologies both renewable and conventional, even before the first refurbishment option, may be very valuable.
- **Estimating FOV at the time of original investment is complex and often neglected, but it may be valuable if a practical estimation method is developed.** For a plant approaching the end of its expected operating life, the method for deciding whether to retire or refurbish is relatively straightforward in principle. However, estimating the present value of FOV at the time of the original investment is far more complex because of the wide range of types and timing of different follow-on options and the lack of information about the likelihood or present value of such options at the time of investment. On the other hand, the existence of FOV among existing plants that are 30 years old or older suggests such value is widespread and substantive even though it may be uncertain.

Investment decisions are always made with imperfect information about the future, and the longer the investor time horizon the greater the investment uncertainty. The end of life value remains uncertain due to many factors including environmental regulations and fuel prices, both of which have experienced significant changes in recent decades. However, including RV and FOV in valuation estimates may change the relative attractiveness of technologies that provide more long-term value than less capital-intensive technologies that offer better short-term economics.

[2] In this case, if the price of power is not changed, the net present value (NPV) increases. Alternatively, the price can now be lowered to achieve the same NPV for the investor.

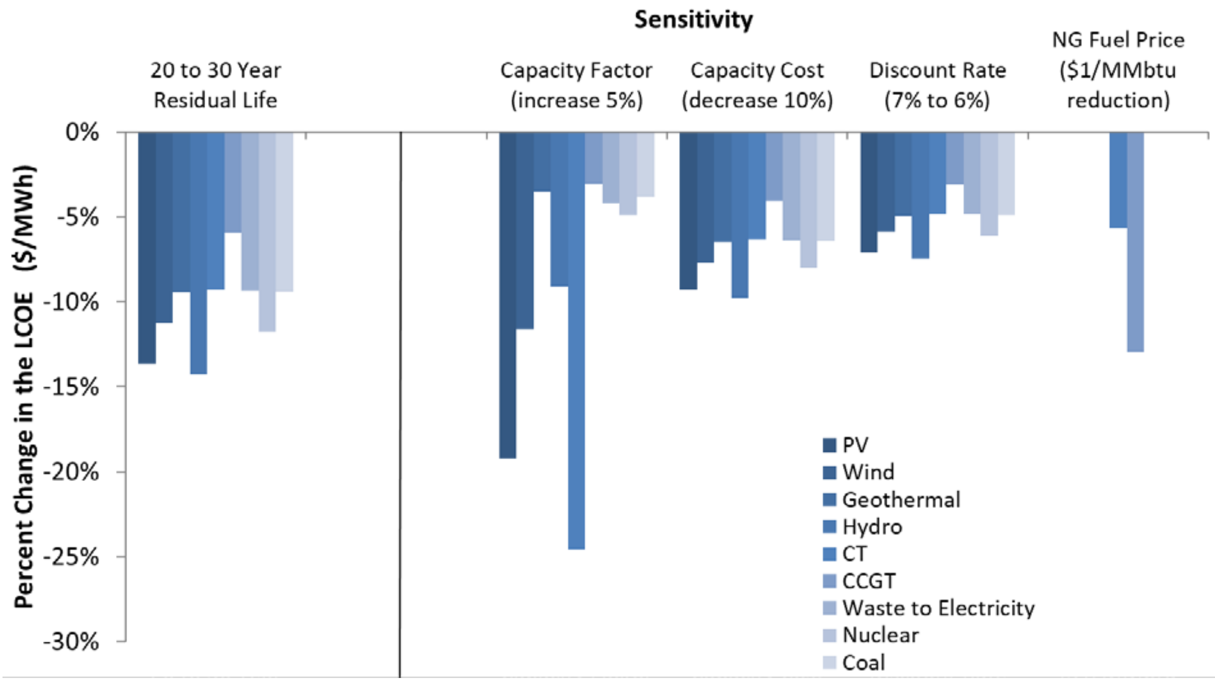

Figure ES-1. Percentage change in LCOE that is due to including RV compared with reductions due to some varying commonly explored sensitivity factors, for various generating technologies

This work raises the question of how FOV might be better valued at the time of investment and by whom. Large companies and pooling structures may allow the benefits of portfolios of assets to be considered. Government-owned hydroelectric facilities (such as those run by the Bonneville Power Administration) and municipality-owned waste-to-electricity plants are examples of assets that provide low-cost power over long lifetimes under contractual arrangements that are attractive to both owners and those who operate but do not own plants.[3] These types of considerations support the idea that ownership of long-lived assets might, in some cases, be better-suited for municipal, federal, or other public entities. A more open question is whether private- or public-sector entities—such as capital funds with long-term investment horizons and university endowment funds—might find the option to capture the "second life" of such generation assets attractive. If so, they may be willing to provide upfront capital or pay a smaller sum for a follow-on option or right to purchase remaining operational life after 30 years, which might reduce the nearer-term cost of energy.

[3] The low-cost power provided by government-owned facilities is in part due to the low cost of capital provided through the bond market. This low cost of capital is achieved as a result of the longer time horizon available to such an authority, but it is also due to the credit quality of the government.

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1 Introduction

An electricity-generating asset can be characterized by various lifetime intervals, each of which is associated with one or more value intervals (Figure 1, next page). When the asset is newly installed, its electricity generation is often contracted to be sold for a specified period at a predetermined rate. This fixed *contracted life* is associated with the *contracted value* of net earnings during this period. However, generating assets typically have a longer *financial life* over which investors are expected to recover capital and earn a rate of return. Between the end of the contracted life and the end of the financial life, the asset produces a *residual value* (RV) of net earnings. Finally, an asset's *actual operating life* can be even longer than its financial life—often owing to improvements made to the asset later in its life—in which case, it produces a *follow-on value* (FOV) of net earnings during the period following the end of its financial life.[4] The actual operational life depends on both how long the asset can generate power and how long it is economically beneficial to continue operating. The durations of all intervals vary based on technology, market behavior, and contract participants.

At the time of the decision to invest in a generating asset, the RV and FOV are uncertain, but these values can be substantial. Including RV in the projected financial valuation can affect the asset's economics more than changes to the fuel price, utilization, and rates of return, depending on the technology and contract length. Including FOV in financial analyses has two main potential economic benefits and sources of present value. First, increased system life allows assets to generate additional positive cash flows over a longer period. Second, because the decision to make follow-on investment often occurs well into a generating asset's life, the asset owner retains an *option* to extend the lifetime when it is beneficial to do so. Although the uncertainty surrounding the lifetime of different technologies and future energy values makes the present FOV uncertain, the ability to choose to extend asset life under favorable conditions—or not extend under unfavorable conditions—in the future offers the potential for added value with little downside risk. In any case, financial analyses that do not capture the value associated with all intervals across a generating asset's lifetime may undervalue the asset. Conversely, upfront recognition of RV and FOV by project developers, financiers, and others could result in lower energy prices.

In this report, we explore the opportunities and risks associated with the RV and FOV of electricity generators. To illustrate the value of RV, we assume a contract period of 20 years and an RV period of 10 years, although these parameters could vary substantially in practice. We discuss the RV and FOV phases in the context of discounted cash flow (DCF) that results in the levelized cost of energy (LCOE) metric used in technology benchmarking. Also, the data allow a discussion of fixed contracts, such as power-purchase agreements (PPAs), used in electricity markets analysis and grid modeling. We also consider the potential application of RV and FOV, which have historically provided value to thermal plants, to wind and solar generation technologies, in the context that most of these renewable assets are still operating under their original electricity contract, given how recently they were installed.

[4] Although the distinction between RV and FOV is inherently arbitrary, for this report, we consider RV to be the period over which operations are expected with relatively normal operating expenses and FOV to be the period during which it is necessary to make significant strategic decisions about continuing to operate. RV or FOV may include a negative component for decommissioning at point of retirement net any salvage value.

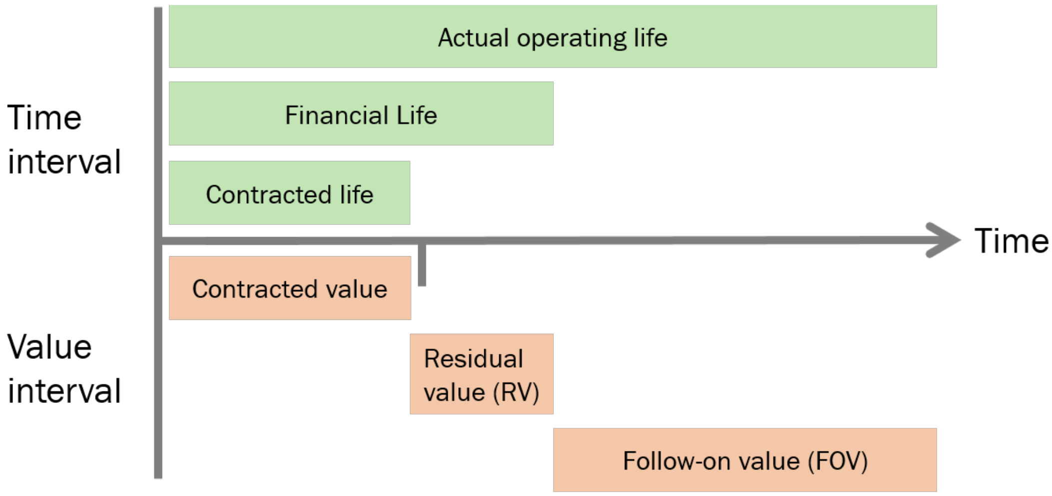

Figure 1. Illustration of the time and value intervals discussed in this report

The report is structured as follows. Section 2 provides background on the net present value (NPV) and LCOE metrics used to value generating assets. Section 3 discusses the differences between the lengths of financial contracts and operational lives for generation technologies. Section 4 examines the inclusion of RV when estimating LCOE and NPV for various technologies. Section 5 explores the potential benefits of including FOV in financial analyses. Section 6 provides conclusions and suggestions for future work.

2 Background on NPV and LCOE

In the electric utility industry, estimating the potential future value of capital investments on a risk-adjusted basis is central to the investment decision process and this includes assessing future changes to the electricity grid. Those modeling electric-generating assets—include investors, grid operators, analysts, and regulatory authorities—often use a project's NPV to inform investment decisions, estimated by summing the discounted expected value of the uncertain net cash flows over a specified period and netting them against the original investment. If the NPV is greater than or equal to zero, the project is economically attractive on a cost of capital basis, and indicates that the investment may be undertaken.[5] However, the period over which an investment is paid back varies by the party performing the calculation. Electricity generation assets often receive funding from multiple investors, each with their own specific expected cost recovery duration. For example, a tax-equity investor may only expect to own an asset for 5–7 years, a debt provider almost always sets the debt term to shorter than a project's contract life, and other equity investors may have a range of expectations on investment duration (as may other interested parties, such as grid operators and regulators). Regardless, when system owners price the electricity they sell—such as under a power purchase agreement (PPA)—they assume a certain operational lifetime at which their NPV will be zero or greater.

A related metric is LCOE, a single cost of energy (in $/MWh) at which NPV is zero for the specified discount rate over a specified period. Whereas a PPA prices electricity during an asset's contract life, LCOE captures the levelized cost over the asset's estimated operational life.[6]

Estimates of LCOE for electricity-generation technologies are widely reported, especially within the context of demonstrating improvements in technology cost or performance over time and progress toward reaching electricity price targets.[7] LCOE estimates vary widely across and within studies, even for the same technologies, depending on assumptions about capital costs, utilization, discount rate (or cost of debt and equity for some analyses), fossil fuel prices, conversion efficiency (or heat rate), project life, and so forth (e.g., WEC 2013; IRENA 2015; Stark et al. 2015; Lazard 2016 2017; EIA 2017c; BNEF 2016; NREL 2017a, 2017b; Chu and Majumdar 2012). For example, Branker, Pathak, and Pearce (2011) review a large number of photovoltaic (PV) studies and find the LCOE estimates vary by a factor of four or more, depending on assumptions. IRENA (2015) and Lazard (2016) find similar results across a broader range of technologies, with estimates differing by a factor of two or three across the data set.

Despite the widespread use of LCOE for comparing different generation technologies, the use of this metric has important limitations and caveats, especially with regard to overinterpreting the

[5] There are several limitations with the use of NPV in this standard form. For example, NPV does not take account of the size of the investment, which can be important when the total capital that may be invested is limited. This can be resolved using a complementary measure of NPV per dollar invested.
[6] If an equity investor would calculate LCOE, it would use return on equity (RoE) as the discount rate.
[7] For example, the U.S. Department of Energy's Solar Energy Technologies Office, through its SunShot Initiative, aims to reduce the LCOE of utility-scale PV to $30/MWh and concentrating solar thermal baseload power to $50/MWh by 2030 (DOE 2017).

meaning of observed LCOE differences (e.g., see EIA 2017a, 2017b; Jenkin et al. 2013). Some of the commonly stated reasons for not directly comparing the LCOEs of different electricity-generation technologies that have different capacity factors or even times of use for the same capacity factor include intra-day electricity price variation, variation in ability to provide capacity, and locational price variation.[8]

In particular, the assumed calculation period has important impacts on LCOE estimates. The different time horizons of stakeholders and investors in a project can create ambiguity in the appropriate calculation period, because some do not view an asset having any economic life beyond a power contract (i.e., they assume the project will be decommissioned at this point), while others may believe that an asset will operate for its full technical lifetime (the length of time the physical asset is expected to last). In practice, an asset will most likely operate as long as it is economical, which may be longer than its contract life but shorter than its technical life. Throughout the literature, assumed lives used to estimate capital recovery or LCOEs vary widely even for the same technologies. For example, the investment analysis in EIA (2017b) uses a 30-year contract life for all technologies for investment decisions or for calculating LCOEs, but then models these technologies to operate much longer in the capacity expansion and future scenario analysis. The National Renewable Energy Laboratory's Annual Technology Baseline assumes a 20-year life in its base case but provides sensitivity analyses based on longer operational lives (NREL 2017a, NREL 2017b).[9] Assuming relatively short lives may bias investments against technologies with longer expected operational lives and higher capital costs. Conversely, some studies assume technology-specific operational lives when estimating LCOEs. For example, VGB Powertech (2015) assumes contract lives equal to operational lives of 25 years for solar photovoltaics (PV) and wind, 30 years for combined-cycle gas turbines (CCGTs) and combustion turbines (CTs), 40 years for coal thermal, 60 years for nuclear, and 100 years for hydroelectric. Although equating financial and operational lives may better represent an asset's inherent economic value, LCOE estimates based on this assumption may not reflect actual financing availability. Such estimates may also underestimate benefits from capacity upgrades, or costs from refurbishment.

[8] These factors may lead, for example, to a PV asset with a higher LCOE than a wind asset (at a similar location) still being more economically attractive, even if the assets' operational and contract lifetimes are the same. This can occur because PV generates electricity during traditionally higher-value peak demand periods—at least at low variable renewable energy penetrations—so the average hourly price of electricity during these peak periods will be higher compared with the average price estimated across the entire day.

[9] The contract life is set equal to the operational life in some of the Annual Technology Baseline's sensitivity analyses.

3 Differences between PPA Periods and Operational Lives of Generation Assets

The PPA is a common electricity-purchasing mechanism for many generating technologies in regulated and restructured markets. PPAs set the price per unit of electricity ($/MWh) for a specified period, which may be fixed or variable over the contract life. PPA periods are commonly 15–25 years or less, often much shorter than expected operational lives, because electricity off-takers often do not want the risk of a long-term liability (despite the benefit to the asset owner that could translate into a lower PPA rate).

Figure 2 shows the distribution of contract lengths for existing (put in place between 2008 and 2017), expired, and planned wind, solar, hydroelectric, and biomass plants for renewable portfolio standard (RPS)-related contracts in California (CPUC n.d.). The contracts are a mix of PPAs, feed-in-tariffs, and qualifying facilities. A recent analysis by Bloomberg New Energy Finance (BNEF 2016) suggests that the lengths of PV PPAs have become much shorter, with 10 years becoming more common.[10] Such a term is less than half of the likely future PV operational life assumptions. As such, revenue from post-PPA asset operation (i.e., RV) is increasingly important to account for the expected project value.

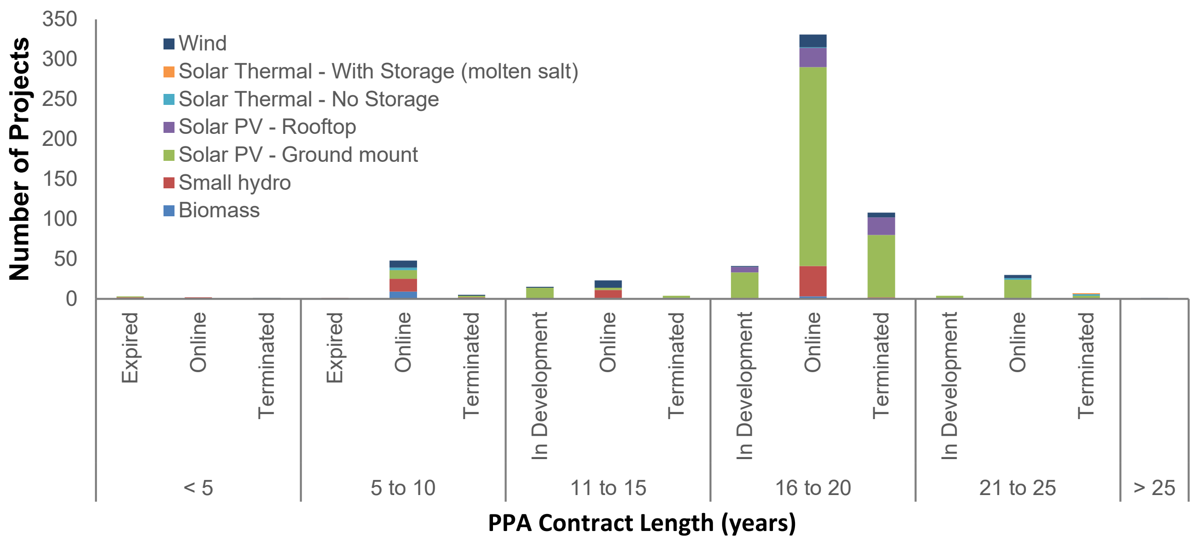

Figure 2. Distribution of contract lengths for wind, solar, hydroelectric, and biomass in California (CPUC n.d.)

The typical 15-year to 25-year length of many PPAs is often much shorter than the asset's operational life.

[10] BNEF states that the increase in shorter-term contracts is primarily a result of state-mandated lengths for avoided-cost contracts (under the Public Utility Regulatory Policies Act or PURPA), intense competition by project developers (that may compete over more favorable terms to the offtaker, such as a shorter contract), lower wholesale pricing driven in part by historically low natural gas prices (which may increase the confidence that wholesale prices will be higher at the end of the contract), as well as an increase in offsite corporate PPAs and hedging instruments.

When the PPA length is significantly shorter than the expected operational life, investors may consider how to include an estimate of the post-PPA RV in their NPV calculation. However, at the time of the investment decision, the future RV may have a wide range of possible values for several reasons:

1. The asset's operational life beyond the end of the PPA period is less certain, because it no longer has an energy off-taker at a fixed price, and with each year of operation, there is a higher likelihood of the need for repairs or replacements.
2. It is uncertain whether a new follow-on PPA could be signed and how the asset's future economic value might be based on wholesale electricity sales.
3. The wholesale electricity price at the end of the PPA period is highly uncertain.[11]

These factors increase the risk and uncertainty associated with future net cash flows beyond the end of the PPA, suggesting that—when making the original investment decision—a higher discount rate should be applied to such cash flows, or estimated probability calculations should be used.

For many generating technologies, one approach is to estimate LCOE based on an operational life of 30 years. This is the choice, for example, made by the U.S. Energy Information Administration (EIA) for its LCOE analysis for different technologies (EIA 2017b). However, in EIA's multi-decade projections of capacity additions and retirements (EIA 2017c), it models the investment decision and an initial market price for each technology using a 30-year financial life but allows certain technologies to continue operating after their capital recovery period as long as it is economical to do so, because operational lives vary considerably by technology (EIA 2017c).[12]

The long operational lives of U.S. generators are indicated by the ages of existing plants, estimates of future operational lifetimes, and observed retirement ages. Figure 3 shows that the current ages of conventional generating plants are commonly greater than 30 years, with substantial coal, nuclear, and natural gas thermal capacity built 40 to 50 years ago and several hydroelectric facilities built more than 80 years ago still in service. The relative youth of wind and solar plants in Figure 3 likely does not suggest the full potential operational lifetimes of these technologies accurately owing to their newness and the potentially life-extending effects of technological advances over the last decade. Overall, these data show that the expected operational life for many technologies generally exceeds the typical contract lengths of offtake agreements, often by many decades.

[11] For the purposes of this report, we define uncertainty as the standard deviation of the expected value. We do not assume a normal distribution.

[12] After the assumed financial life, a marginal energy cost basis is calculated that includes technology-specific annualized incremental capital recovery to reflect anticipated future refurbishments. The decision to retire a plant for economic reasons is based on not making full capital recovery in addition to variable costs for three successive years.

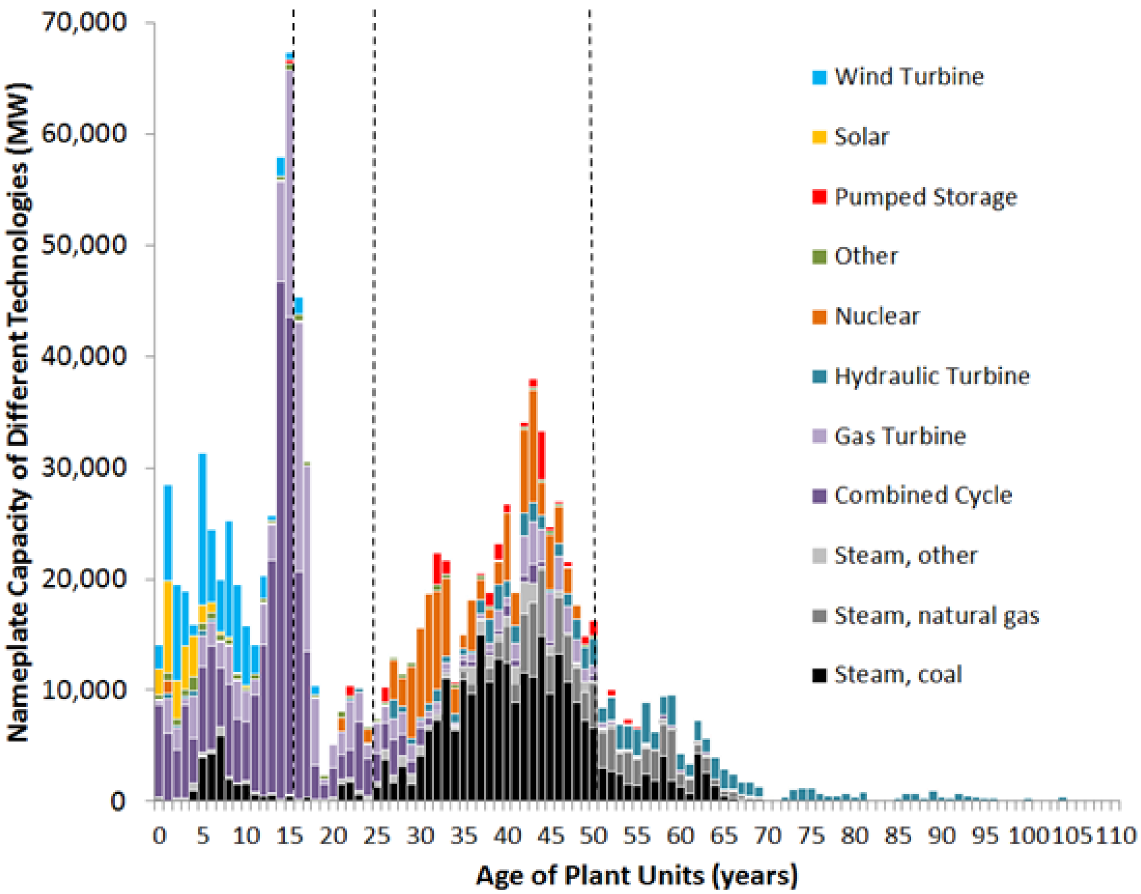

Figure 3. Ages of U.S. utility-scale generating capacity by technology (S&P Global 2017)

U.S. plants often continue to operate after 50 years, with hydroelectric plants often lasting 80 or more years.

Figure 4 depicts various analyst estimates of generator operational life. Although these estimates vary among generator technologies, they indicate that estimates of future operational life of new generation investments are often much greater than the typical 15-year to 25-year PPA. Substantial variation in operational life estimates also exists between analysts for individual technologies; for example, the estimates for CT and CCGT generation vary by a factor of two.[13] Taken together, however, analysts clearly assume many generators continue to operate well beyond the length of a typical PPA.

[13] Some of this difference may reflect ambiguity about what is being estimated, with regard to whether the life is a mean, median, or most likely value and whether the meanings of terms such as operational life, physical life, and economic life differ across the sources. We consider the terms operational, physical, and economic to be equivalent—for consistency, we use the term operational to describe an asset's lifetime until retirement.

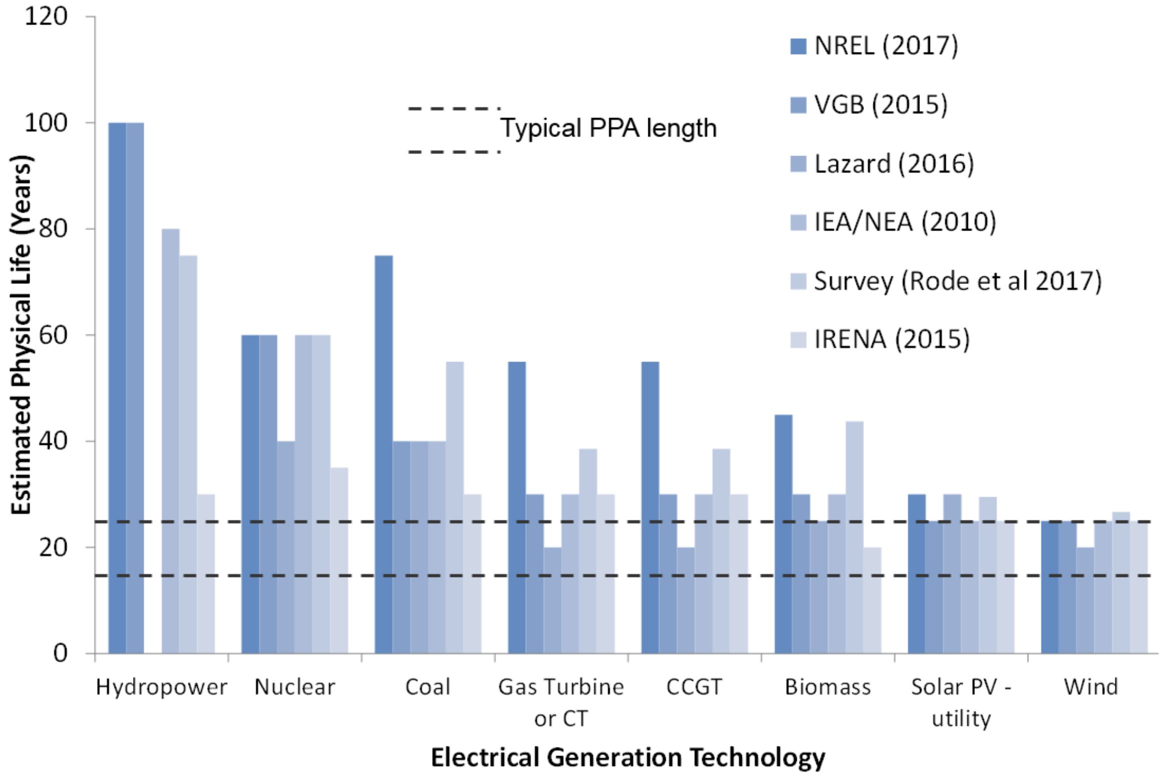

Figure 4. Estimates of average expected operational life for newly installed, utility-scale generation technologies from six different sources: NREL 2017a; VGB PowerTech 2015; IEA, NEA, and OECD 2010; Lazard 2016; Rode, Fischbeck, and Páez 2017; IRENA 2015

The Rode, Fischbeck, and Páez (2017) estimates are the simple average of eight cited sources. Lazard (2016) does not estimate hydroelectric life.

Figure 5 compares the length of an average contract (represented by a 20-year PPA) plus RV, a range of estimated average operational lives based on several studies, and actual average operational lives based on recent retirements for coal and natural gas thermal plants from a study by Rode, Fischbeck, and Páez (2017). The third and sixth columns shows the 10th, 30th, and 50th percentiles for the retirement ages for coal and natural gas plants, respectively. The figure shows that coal and natural gas plant retirement ages are typically longer than estimates of operational lives and much longer than contracts lives, even when extended to allow for RV.[14] For example, the 50th percentile retirement age for natural gas and coal plants built before the 1960s is more than 60 years (Rode, Fischbeck, and Páez 2017), which is often 20–30 years higher than average life estimates. The lives of even the 10th percentile of coal plants—representing plants that retired relatively early—are longer than 40 years and above the lowest estimates of average physical life.[15]

[14] The past is not necessarily a good guide to the future, and experts may be basing their estimates on a wide range of uncertainty parameters including the greater risks to plant owners of the shift to more restructured markets.

[15] Again, the exact meaning of the future estimates is uncertain here. Estimating an average requires knowledge of the future distribution, which is unknown and likely not particularly intuitive. The estimates likely represent most likely or median values, although inconsistency in what is being estimated may contribute to some of the observed variation.

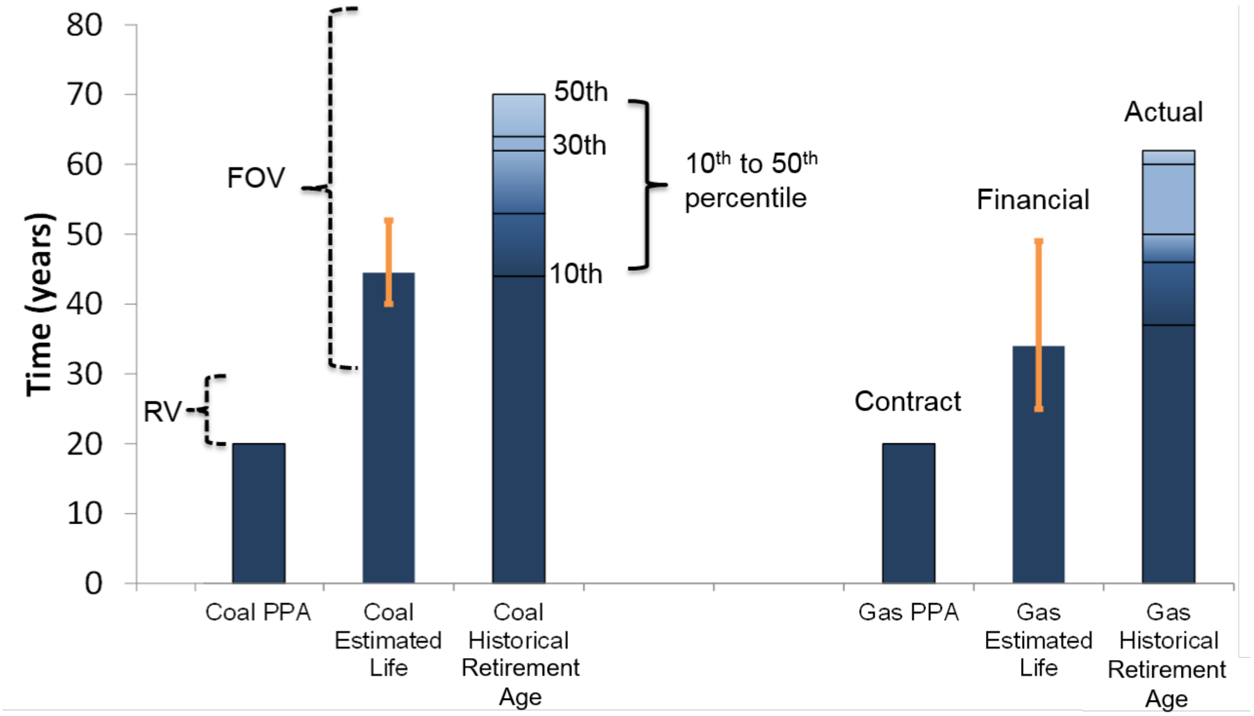

Figure 5. Difference between PPA lengths (actual and adjusted for RV), a range of estimated average operational lives from different sources (orange error bars), and the actual average operational lives based on recent retirements for coal and natural gas plants

Sources: The range of estimates is from VGB PowerTech (2015), IEA, NEA, and OECD (2010), Lazard (2016), and Rode, Fischbeck, and Páez (2017). Percentile estimates are from Rode, Fischbeck, and Páez (2017). Because retirement ages are generally far longer than contract lengths, the RV and FOV can be important sources of expected value. The RV and FOV ranges in the graphic follow the illustrative ranges provided in this report.

Mills, Wiser, and Seel (2017) find the most common recent retirement ages to be 50–60 years for coal thermal units and 40–50 years for natural gas CTs and steam turbines.[16] Similarly, Figure 5 suggests that an assumed financial life of 30 years including RV is conservative for thermal technologies relative to the full operational life.

Asset lives are in practice often extended via minor or major refurbishments that are more cost-effective than retirement and replacement with new generation (see Section 5). The relatively high prices paid for recent purchases of older hydroelectric plants also support the market view of these assets' long-term economic value. For example, in 2013 NorthWestern Energy purchased 11 hydroelectric plants with a total capacity of 600 MW for over \$2,000/kW; all but one were built before 1930, and they all have Federal Energy Regulatory Commission license expirations that extend to 2040 (NorthWestern Energy 2013). Conventional thermal turbine-driven technologies can also realize substantial value beyond 30 years. For example, Covanta operates 40 U.S. waste-to-electricity facilities, which the firm either owns or runs on behalf of municipal owners. In recent years, waste contract transactions have extended 90% of anchor

[16] Mills, Wiser, and Seel (2017) show CCGT retirement ages of 30–40 years. It would be interesting to understand if these relatively short lives were associated with rapid decreases in heat rates for new CCGTs in recent decades or other factors.

municipal client contracts for an average of about 10 years (Covanta 2017a, 2017b). Such contract extensions suggest expected operational lives of 40 to 50 years or more. In many ways, after 30 years the cash flows from such plants are less risky and have considerable upside, because debt was typically paid off after 20 years. This is recognized by Covanta:

> "As our waste service agreements at facilities that we own or lease expire, we intend to seek replacement or additional contracts, **and because project debt on these facilities will be paid off at such time,** we expect to be able to offer rates that will attract sufficient quantities of waste while providing acceptable revenue to us" (Covanta 2017a) [emphasis added].

The ownership and contract structure of these assets are also of interest. In 60% of cases, Covanta owns and operates the plant. In the remaining 40% of cases, municipal clients own the facilities and pay Covanta a service fee, which is structured to include incentives to share in the net revenue (Covanta 2017a).

The decision to continue operating existing assets after 30 years or more of operation is different from whether or not to invest in new plants of the same technology, demonstrating the importance that sunk costs, or lower refurbishment costs, play in extending asset lives. For example, in contrast to extending the life of existing assets, which appears widespread across most technologies, investments in new generating assets for different technologies follow distinct boom and bust cycles that reflect a wide range of policy and economic considerations. This is seen in Figure 6, which shows the emergence and subsequent decline of hydro, followed by the same trend in fossil steam plants, nuclear, and new natural gas generation as well as the more recent rise of wind and solar.

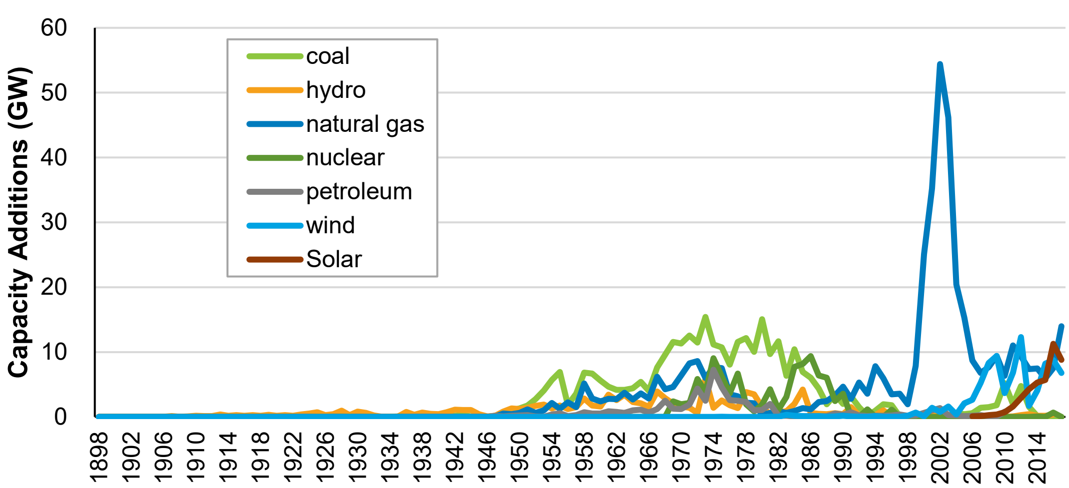

Figure 6. New U.S. installed capacity by technology (1898–2017)

Source: S&P Global 2017

4 Including RV when Estimating LCOE and NPV

In this section, we define how to incorporate RV in an LCOE equation and an NPV equation, estimate the impact that RV has on LCOE, and compare the impact across technologies under a set of illustrative assumptions.

4.1 Framework for LCOE and NPV Estimates with and without RV

LCOE is a summary metric that distills information from a more complete analysis of the investment obtained via DCF analysis. Over the operational life of the asset (time t = N), LCOE is defined as follows (see, e.g., Branker, Pathak, and Pearce 2011):

$$\text{LCOE} \times \sum_{t=1}^{t=N} \frac{E_t}{(1+r)^t} = \sum_{t=1}^{t=N} \frac{R_t}{(1+r)^t} \qquad (1)$$

Where E_t is the annual energy generated (in MWh) and R_t is the total annual cost of (or revenue required for) electricity in year t, the discounted value of which is summed over the operational life of the asset (N years in this case). When the expected NPV = 0, the annual discount rate (r) is also equal to the nominal (after-tax) RoE term in the weighted average cost of capital (WACC) for the project.[17] Such a condition sets the minimum revenue requirements for investment, which is a common application of LCOE. Hence, LCOE expresses the breakeven cost of energy at which annual gross (pre-tax) revenue cash flow (R_t) over the life of the project exactly services equity and debt at the planned RoE/discount rate after taxes and fixed and variable operations and maintenance (O&M) costs, including fuel costs. The lifetime of the equity investment often is longer than the term, or tenor, of the debt.

$$\text{LCOE} \times \sum_{t=1}^{t=N} \frac{E_i}{(1+r)^t} = \sum_{t=1}^{t=N} \frac{P_i \times E_i}{(1+r)^t} \qquad (2)$$

$$\text{LCOE} = \sum_{t=1}^{t=N} \frac{P_i \times E_i}{(1+r)^t} \Big/ \sum_{t=1}^{t=N} \frac{E_i}{(1+r)^t} \qquad (3)$$

The LCOE consists of two parts: a fixed part that includes capital recovery and fixed costs, including debt, and a variable part that includes energy costs in terms of \$/MWh.[18] For the special case in which energy production is assumed to be the same in all years, the general expression can be simplified to:

$$\text{LCOE (\$/MWh)} =$$

[17] This is only true when NPV = 0. If the NPV is positive, the project rate of return (RoR) is greater than the discount rate, and vice versa.

[18] Whether the discount rate (or RoE) is nominal or real, or pretax or after tax, is a matter of choice provided the associated cash flows and debt characteristics are treated consistently.

$$\frac{I \times CRF + \text{Fixed O\&M}}{E_{Annual}} + \text{Fuel (\$/MWh)} + \text{Variable O\&M (\$/MWh)} \qquad (4)$$

Where CRF is the capital recovery factor:

$$CRF = \frac{r}{[1 - (1+r)^{-N}]} \qquad (5)$$

The NPV for an investment can be written as follows (in this case assuming a 20-year original PPA and a 30-year operational life)[19]:

$$NPV = I + \sum_{t=1}^{t=20} \frac{C_{Net,\,t}}{(1+r)^t} + \frac{RV}{(1+r)^{20}} + FOV \qquad (6)$$

The four terms that make up the NPV expression include the following:

- Investment (I) needed to build the plant (\$), simplified here to take place at t = 0, which could include financing costs incurred during construction.
- Discounted annualized net cash flow (\$ per year) ($C_{Net,\,t}$), the gross revenue less fixed and variable O&M (including fuel), principal and interest repayment, and taxes. Depreciation affects cash flow indirectly through tax effects.
- Residual value (RV) (\$) in year t for a specified future period, illustrated here for t = 20, is the present value in year 20, estimated as the sum of discounted net cash flows between years 21 and 30.
- Follow-on option value (FOV) (\$) is the present value of the sum of net cash flow in year 0 attributed to expected economic value of different follow-on options, i.e., to continue operating with or without further investment or to retire (see Section 1 and Section 5).

For a more conservative estimate of LCOE, the final FOV term is set to zero, and the present values of first and second term on the right-hand side of Equation (6) are set equal to the original investment (I) so that the NPV is zero. This is more conservative because the value of follow-on options that constitute FOV is often expected to exceed zero (depending on market and technology), so at the expected NPV would be positive in real terms.

The near-term RV at the end of the PPA will be uncertain at the time of the original investment, because future prices and the asset life are uncertain. Nevertheless, it is important to include at least a conservative estimate of the RV in the NPV or LCOE estimate, particularly for short PPAs. BNEF (2016) examines inclusion of RV for PV for years 11 to 25 when considering the potential risks associated with PPAs of only 10 years in length (corresponding to recent trends in Texas and the Southeast). Methods of estimating RV include variants of the following:

[19] This could be changed from 20 to 25 or 30 years, and then the RV might be extended for 10 years from that point depending on the technology.

1. **Extension of PPA at similar terms**. This method benefits from simplicity, but it may be unrealistic depending on future price changes since the original PPA was signed, which are highly uncertain at the time of original investment.
2. **Extension of PPA based on expected future wholesale energy and capacity markets.** This might include estimating future energy prices at the time of original investment using:
   - Forward curves, which provide market-based data on future prices[20]
   - Extrapolation of existing price trends
   - Estimated price forecasts

   Such estimates entail considerable uncertainty.
3. **No contract established but assuming sales into future expected energy and capacity markets**, with estimates made as for the second method above.

BNEF (2016) uses all three methods, and it finds that different stakeholders (project developers, lenders, and investors) use different methods to estimate post-PPA RV and that such estimates may vary widely.[21] The analysis in the BNEF report assumes, however, that the time over which the RV was estimated was known and fixed (at 15 years, for a 25-year total calculation period), when in fact the lifetime will be uncertain. Section 4.2 describes a modification of LCOE to include RV, based on years 21 to 30 after the first 20 years, although this approach may be modified to incorporate different timescales and the other three methods. The inclusion of FOV beyond the 30-year financial life chosen for full capital recovery life is discussed in Section 5.

4.2 Estimating the Impact on LCOE of Including RV Using a Discounted Cash Flow Approach

Here we show the importance of including RV, using PV to illustrate the impact of extending the equity's capital recovery period from 20 to 30 years, where in both cases a conservative estimate of the operational life is 30 years.[22] Using 20 and 30 years is reasonable, because many estimates of LCOE or PPA prices consider full capital recovery over these periods (EIA 2017b; Lazard 2017; NREL 2017a; NREL 2017b). For the DCF calculation and the corresponding LCOE, we use the revenue requirement approach described in Section 4.1, assuming the equity investor earns a RoE for the project over either 20 or 30 years. In both cases, the RoE in each year is estimated net of principal and interest payments on debt, which is typically amortized over a shorter period and assumed to be 20 years in both cases in this example.

For an operating life of 30 years, inclusion of the expected post-PPA RV when pricing a PPA with a shorter term allows the LCOE to be lower over the first 20 years. Many analysts include

[20] See Platts (2012) for a more detailed discussion of forward curves and their limitations.

[21] BNEF summarizes the several methods for estimating RV, which vary in their approach and degree of sophistication, mostly centered around the future price at which a system's energy is sold. The simplest approach assumes no change in pricing, followed by extrapolating current and historical pricing. More sophisticated approaches involve using electricity pricing estimates from several companies that forecast pricing, sometimes at the hub or even the nodal level.

[22] Similar analysis for RV could be extended for years 31–40 or later. Extending the capital recovery period from 20 to 30 years is from the perspective of the asset's equity holder. Although the asset's debt holders also recover capital, from the perspective of the equity holder, debt is simply another expense of the project.

the entire expected operational life this way when estimating the LCOE, and this assumed lifetime is desirable and typically necessary if the market is competitive, with alternative suppliers competing and able to make similar investments. On the other hand, the operation beyond the financial life (i.e., FOV) is often ignored or heavily discounted for investment decisions, which can leave the broader question of longer-term value ambiguous (e.g., Lazard 2016). In this section we consider the inclusion of RV explicitly, and Section 5 discusses FOV, although the age boundary between the two is somewhat arbitrary.

Figure 7 shows the DCF approach for estimating PV LCOE with an operating life of 30 years, where the LCOE is estimated over 20 or 30 years. In the left part of the figure, the nominal annual net cash flow over 20 years is represented with orange vertical bars, and the nominal LCOE for a 10% nominal RoE over the same period[23] is the horizontal orange line.[24] The nominal annual net cash flow over 30 years is represented with blue vertical bars, and the nominal LCOE for a 10% nominal RoE over the same period is the horizontal blue line. The last 10 years of the 30-year case has significantly higher net cash flows because it has no debt service. In both the 20-year and 30-year cases, the project has an identical RoE and, importantly, the NPV is the same (zero) even if the plant operates for 30 years in both cases. Under these conditions, the LCOE declines by $7/MWh (or 8% of the original value).[25]

Whether cash flow is considered over 20 or 30 years, net cash flow per MWh is greater than nominal LCOE in the early years, reflecting the effect of accelerated depreciation. The relatively low net cash flow during later contracted years offsets these early, higher cash flows. For the 30-year case, the net cash flow from year 7 to year 20 is significantly lower than the cash flows during the residual period, when the debt repayments have ended.[26] For generating assets whose financial profiles resemble industry averages, the inclusion of RV can be significant.

The assumption that NPV is always equal to zero in LCOE calculations is rarely stressed in side-by-side estimates or modeling studies. Such an assumption may be reasonable when an investor is also the owner (e.g., for municipalities or other publicly owned utilities), but it may not be true otherwise. In cases where the customer is also the owner, that customer still may pay a fee for plant operation as is often the case, for example, for customer-owned hydro facilities and some waste-to-electricity thermal plants (e.g., Covanta 2017a). In contrast, if the investor is not the customer, and the PPA ends after 20 years with no further obligation to the original buyer, then the investor can sign a new PPA, sell power in the wholesale market, or otherwise increase NPV.[27]

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[23] The real RoE is lower than the nominal RoE, and given by real RoE = [(1 + nominal RoE)/(1+ inflation rate)] – 1. A 10% nominal RoE is therefore equivalent to a 7.31% real RoE, if the inflation rate is assumed to be 2.5%.
[24] All computations in this section use a debt-to-equity split of 46%:54%, five-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule, debt cost of 5.5% (nominal), repayment period (or tenor) of debt of 20 years, 40% combined federal and state tax rate, future inflation rate of 2.5%, and no subsidies (similar to Bolinger, Weaver, and Zuboy 2015).
[25] This project RoR is also called the WACC.
[26] On the other hand, the later-year net cash flows will be more heavily discounted (which is not shown).
[27] NPV will be higher provided the energy prices are greater than the fixed and variable O&M costs on a per-MWh basis and the project can still generate electricity. It will not be less, because if the energy prices are below the variable cost the plant will simply not run.

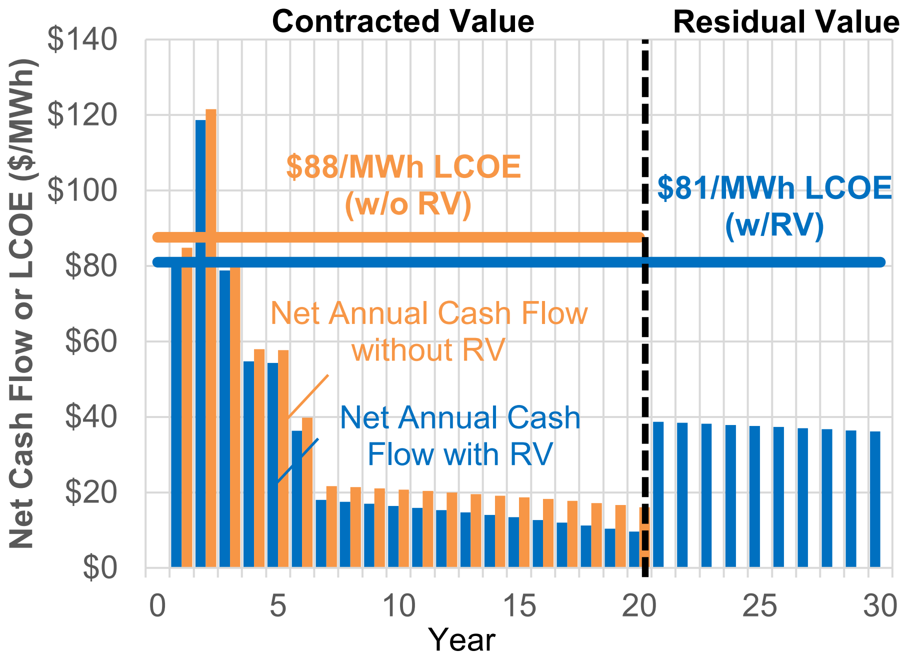


Figure 7. Net cash flow (undiscounted) and its associated nominal LCOE for an illustrative utility-scale PV plant, both with and without RV at 10% after-tax RoE

Source: Capital and operating costs are consistent with the range of estimates in Lazard (2017). If a plant runs for 30 years, the NPV is the same in both cases (equal to zero in both cases).

Figure 7 also shows the LCOE effect of increasing the operational life of a PV plant from 20 years (in orange) to 30 years (in blue). This is different from the common 30-year life assumed in earlier discussion and calculations. For the 20-year case where the conservative operating life is now only 20 rather than 30 years, a new plant would need to be built after 20 years to cover the remaining 10 years. Under these circumstances, the 8% lower LCOE for a plant with a 30-year life (at a 10% discount rate) represents the inherent value due to the life extension.[28,29]

Figure 8 shows how the choice of discount rate (or RoE that makes NPV = 0) affects the relative and absolute importance of including RV for PV and onshore wind. Lowering the discount rate reduces the LCOE significantly for both PV and wind, and including RV has a greater effect in both relative and absolute values with declining discount rate. In this example, reducing the discount rate from 10% to 5% increases the reduction in LCOE due to RV from 12% to 21% for PV and 10% to 18% for wind.

[28] This is also true over the full 30-year life assuming a new PV plant with a 20-year life is built for years 21 to 40. In real terms, the new LCOE and the economic difference in the LCOE would be the same in both 20-year periods. Because of inflation, if expressed in nominal terms the LCOE for the second 20 years would need to increase by 64% (0.64 = (1.025)20 – 1), assuming a 2.5% inflation rate.

[29] The LCOE estimates in Figure 7 are significantly higher than observed prices for recent PV contracts (e.g., under $50/MWh as in Bolinger, Weaver, and Zuboy 2015, BNEF 2016). We attribute most of the discrepancy to subsidies. None of the LCOE values from this analysis includes the effects of mandates or tax incentives, which for U.S. PV include an investment tax credit (ITC) for 30% of the capital cost. Such a tax credit generally reduces LCOE by roughly one third, thereby reducing the LCOEs for the 20- and 30-year cases to $59/MWh and $54/MWh, respectively. The exact effect of the ITC depends on details used to qualify and claim accelerated depreciation, which vary.

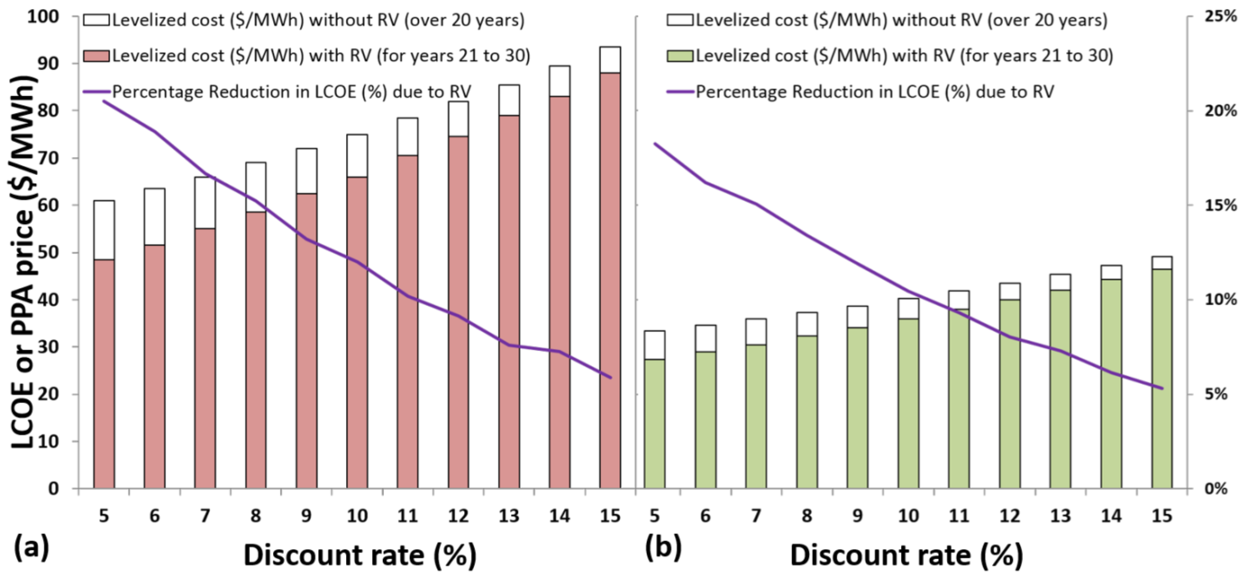


Figure 8. Impact of discount rate/RoE on the relative and absolute importance of including RV (for years 21–30) in real LCOE calculations, for (a) utility-scale PV and (b) onshore wind

Source: Capital and operating costs are consistent with the range of estimates in Lazard (2017). Lowering the discount rate reduces the LCOE as expected for both the 20- and 30-year cases, with the impact of RV on LCOE more pronounced at lower discount rates.

4.3 Impact of RV on LCOE or PPA Prices

Section 4.2 shows the substantial impact of including RV on LCOE over the first 20 years for PV and wind, even though the 30-year NPV may be the same in both cases. The relative significance of including RV for different technologies depends on specific market and contract structure parameters, including the following:[30]

- Investment cost (I)
- Discount rate (r)
- O&M – variable and fixed
- Fuel costs

On the left side of the vertical line in Figure 9, we break down the difference in LCOE for nine different generation technologies, using the simple LCOE formula described earlier (Equation 4).[31] This metric represents the reduction in LCOE over the first 20 years due to including RV for years 21–30. This change due to RV is 6% to 14% depending on technology, and such a reduction may be important in achieving competitive delivered energy prices. In addition to the choice of discount rate, the impact of RV on LCOE is driven by the capital recovery factor,

[30] Other factors include tax rate, capital structure (e.g., debt-to-equity ratio), treatment of depreciation, government lending rate (based on T-bills) and related cost of debt, expected inflation rate, use of subsidies, and so on.

[31] The simple form eliminates effects that might be due to differences in treatment of financing parameters between technologies, like accelerated depreciation, different capital structure ratio, or subsidies. For this all-equity analysis, the RoR and RoE are both set at 7% real (9.7% nominal).

which depends on both the discount rate and the operational life,[32] and by the capacity factor, because a lower utilization will increase the LCOE as the capital recovery is spread across fewer hours of generation. In contrast, the fuel price and variable O&M cost are unchanged in real terms, because fuel and variable O&M are purchased as needed, and the relevant cost is proportional to the quantity of energy produced.[33]

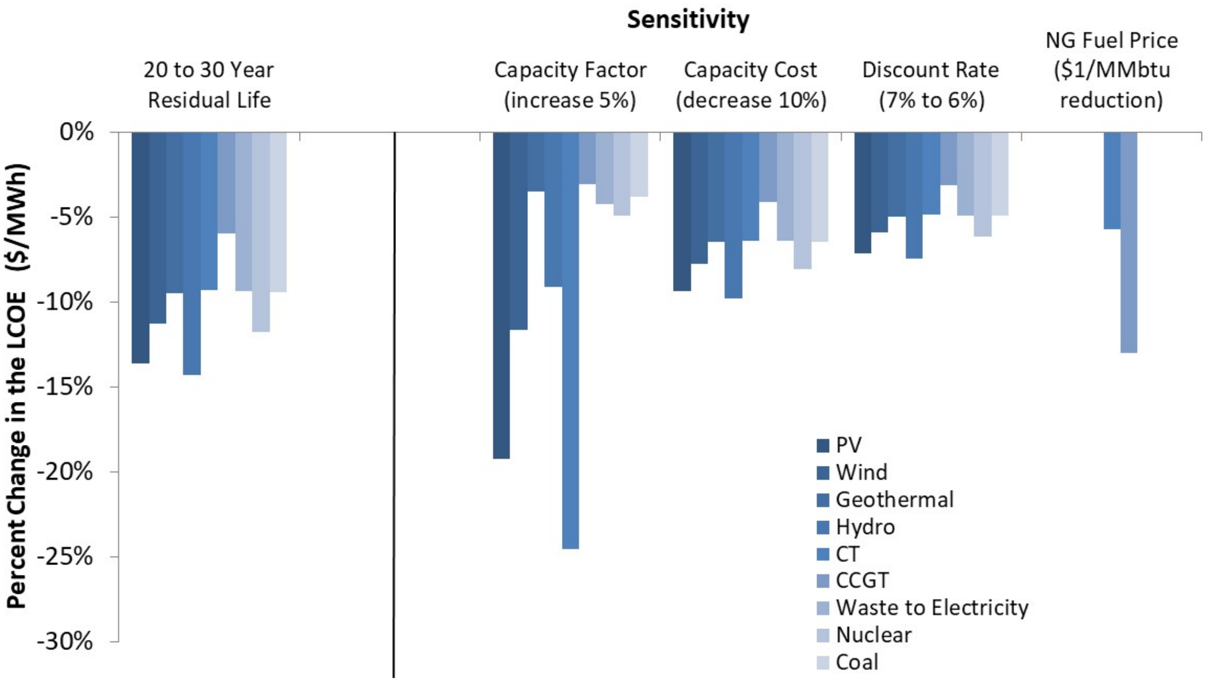


Figure 9. Percentage change in LCOE due to including RV compared with reductions due to some varying commonly explored sensitivity factors, for various generating technologies

Source: Capital and operating costs for these technologies are consistent with the range of estimates given by Lazard (2017) and EIA (2017b). The impact of including RV (for an additional 10 years after year 20) varies from $3/MWh to $10/MWh or more based on technology. The RV impact is often similar to the impact of the other factors that are often considered for investment decisions.

Figure 9 also shows the impact of RV on lowering LCOE compared to the impact of other factors considered for generation investment decisions, which are often investigated using LCOE sensitivity analyses. Such sensitivity factors include fuel prices (shown above for natural gas (NG) only), discount rates, capital costs, and capacity factors. Although the impacts of these factors vary for different technologies and reference case assumptions, they are often comparable to, or less than, the impacts of reducing LCOE during the first 20 years by including RV for years 21–30.

[32] The capital recovery factor is a multiplier that, when multiplied by the investment, yields the annual net cash flow needed to pay back the original investment and earn a RoR over the life of the asset. For this reason, the shorter the recovery period—for any given RoR—the higher the capital recovery factors (because a higher fraction of the original investment needs to be recovered each year).

[33] In this approximation here and elsewhere, we assume fossil fuel prices remain constant in real terms in the future to remove effects from changing fuel prices, which are highly uncertain.

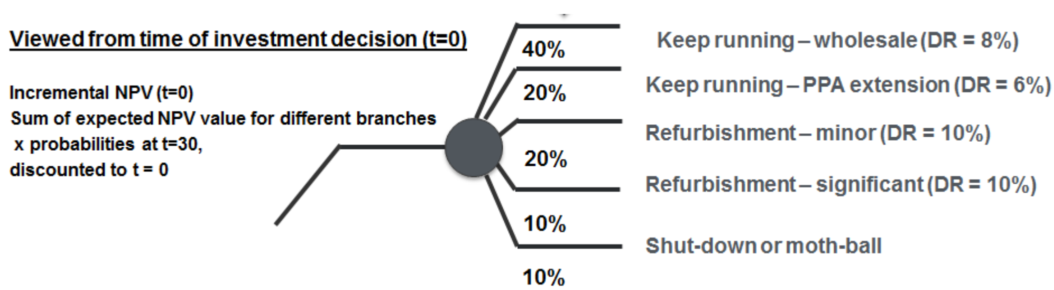
5 Estimating RV and FOV in Theory and Practice: From Investors to Modelers

This section discusses investor modeling and system modeling related to the inclusion of RV and FOV in the valuation of generating assets.

5.1 Investor Modeling

Investors face various choices throughout the operating life of an energy asset: whether to keep operating, how to sell their energy (e.g., reupping a contract, selling into the wholesale market), and how much to invest in the project, from O&M to minor or major refurbishments. One way of visualizing these decisions is through a decision tree, which can also be used to calculate future NPV by assigning an NPV and a probability to each of the different branches. DR = discount rate.

Figure 10 shows an example of a decision tree for an energy asset at a specific moment in time. As time passes, decisions are made, and new information is gathered, the branches and their NPVs and probabilities will change.[34]



DR = discount rate

Figure 10. Example of a decision tree for an electricity-generating asset at year 30 (viewed from the initial investment)

[34] Decision trees can be more complex than indicated here. In this case a probability node reflects probabilities that these decisions will be made, and can be interpreted as follows. There is a 10% chance in year 30 (when viewed from t=0) that the plant will be unable continue operations or be refurbished, and therefore must shut down. Examples that might cause this include environmental regulations or very low electricity prices. There is a 60% chance the plant can keep running without refurbishment, and it will either be more beneficial to sign a PPA contract (40%) or to sell into the wholesale market (20%). Finally, there is a 30% probability that the plant does not need to be shut down, but cannot keep running without either minor (10%) or significant (20%) refurbishment. This illustrative example is a simplification of the actual choices that might be available, including at the time of the investment decision.

In Section 4 we estimate LCOE assuming RV for years 21–30 is included. However, our discussion of the age distribution of the generating fleet for different technologies and retirement ages in Section 3 suggests that, for many technologies, a 30-year life is often more conservative than the actual life, and thus the operating assumptions and valuation are incomplete. Adding the FOV results in an additional term in the NPV equation:

$$\mathrm{NPV} = \mathrm{I} + \sum_{t=1}^{t=20} \frac{\mathrm{C}_{\mathrm{Net,\,t}}}{(1+\mathrm{r})^{\mathrm{t}}} + \frac{\mathrm{RV}}{(1+\mathrm{r})^{20}} + \mathrm{FOV} \qquad (7)$$

$$= \sum_{t=1}^{t=30} \frac{\mathrm{C}_{\mathrm{Net,\,t}}}{(1+\mathrm{r})^{\mathrm{t}}} + \mathrm{FOV} \qquad (8)$$

Where I is the original capital investment, $C_{\mathrm{Net,\,t}}$ is the net cash flow in year t, r is the discount rate, and the present value of the RV in year 20 is estimated by one of the three methods described in Section 4 over years 21–30. At the end of 30 years (or some other chosen financial life), FOV may often be significant, as suggested in Section 3. At the end of its originally estimated financial life, three actions can be taken with an energy generating asset to realize FOV[35]:

1. **Continue operating "as is."** Keep the plant running and then revisit alternative options (i.e., the second and third options noted below) periodically. This option will depend on the condition of the plant. In some cases, a plant will no longer be functional "as is." However, if a conservative estimate of useful life is assumed, then many plants will be able to continue operation.
2. **Make follow-on investments (i.e., refurbishment).** Make minor or major refurbishments, including uprating or repowering with new turbines, extending the operational life as well as potentially increasing capacity (Zawoysky and Tornroos 2008; Hitchin 2011). This option would in most cases only be chosen if the existing infrastructure allows an owner to refurbish a plant at a lower cost than building a new plant.
3. **Shut down the plant.** Shut the plant down either permanently or temporarily (i.e., "mothball" it) depending on future anticipated market conditions and uncertainty, which may entail considering cost variation dependent on the length of closure. Understanding the option value of mothballing may be very important for cases in which closing costs are significant and upside potential for future operation high. Permanently shutting down the plant may incur significant costs, particularly for some technologies; other technologies may be able to sell the equipment and materials for a net gain. However, shuttering costs are typically included in RV (or ought to be).

The alternative is to build a new plant at prevailing costs with an updated version of the technology or a different technology to continue generating cash flow and providing electricity to the grid. As discussed in Section 3, this alternative entails a different type of decision.

[35] A plant can also be sold, but the new owner would then need to choose one of the three options.

Figure 11 illustrates a basic end-of-financial-life decision tree of options and LCOE impacts for an owner of a utility-scale PV system that assumes a consistent cost of equity is used for all 3 value periods (i.e. contracted life, RV, FOV) and considers ranges of lifetime extensions or associated costs. Here the owner can continue operations for five years (with a range of 0 to 10 years), which would reduce the LCOE over the system life by 5% or 2% assuming a 4.5% or 10% discount rate, respectively; refurbish the system at 50% of the original capital expenditure (CAPEX, with a range of 20% to 80%) to extend the asset life by 20 years (with a range of 15 to 30 years) and reduce the LCOE over the system life by 6% or 1% assuming a 4.5% or 10% discount rate, respectively; or shutter the existing plant and build a new plant that will last 30 years and cost 60% of the original CAPEX costs (with a range of 30% to 100%), reducing LCOE over the life of both systems by 7% or 1%, assuming a discount rate of 4.5% or 10%, respectively. Figure 12 summarizes the LCOE impact of these three different FOV options at the time of the original investment, compared with the impact of including RV (in years 21–30).

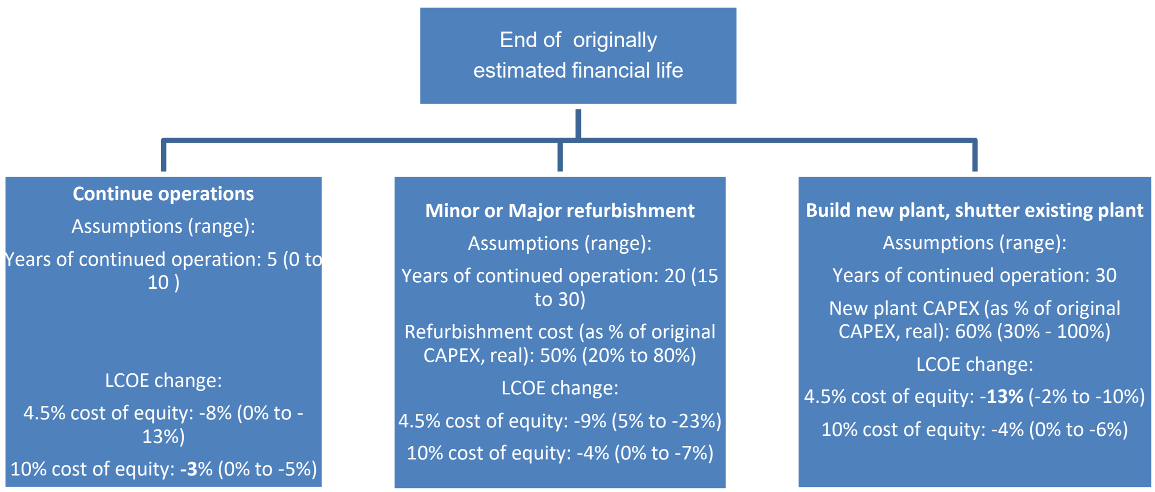


Figure 11. Decision tree of options for FOV at end of utility-scale PV system's useful life

Figure assumes a useful life of 30 years, with an original financial transaction of 20 years. Specific variables, their values, and ranges represent only a subset of possible options. Additionally, the decision tree does not consider the potential subsequent RV and FOV branches from these three options. The black and bold LCOE changes indicate the preferred option under these assumptions.

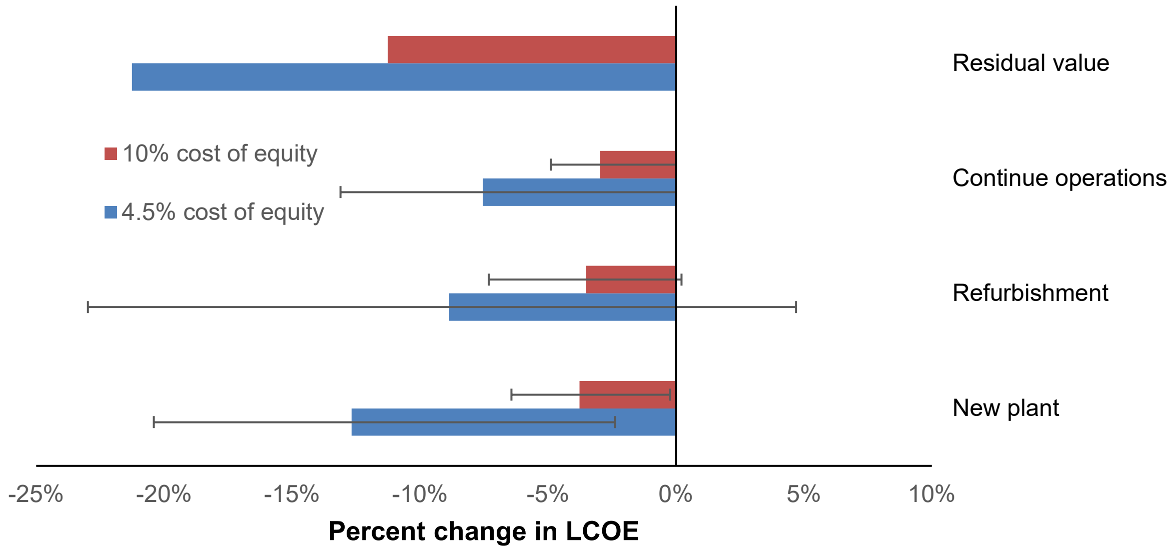


Figure 12. RV and FOV impact on a utility-scale PV plant real LCOE by percentage, 4.5% and 10% cost of equity

Figure assumes an original financial transaction of 20 years with RV in years 21–30 and FOV in years 31–50. Values for RV represent the change in LCOE beyond the original financial transaction, and FOV represents the change in LCOE beyond RV. Error bars show the range in value of FOV from the range of assumptions in Figure 11. Rational investors would not typically exercise the options represented in the figure that have a positive change in real LCOE (higher cost).

These represent only a subset of possible decisions that an asset owner could make over the life of the project. The estimated value from these options will change over the lifetime of the asset as market conditions and technologies change. Based on the illustrative assumptions in Figure 11, at the end of the utility-scale PV project's useful life, the owner would build a new plant at an existing site, however the best option is highly dependent on the range of assumptions. An owner would never choose the options in Figure 11 that increase LCOE, because they always can do nothing, represented here as "continue operations" (with a worst-case scenario of ceasing operations immediately and thus having no impact on LCOE). The choice in this example to build a new plant rather than refurbish PV in part reflects our assumption of declining PV costs. For other technologies with larger differences between refurbishment costs and new construction, refurbishment might be chosen more frequently, which is consistent with historical data.

As demonstrated in Figure 12, using only the subset of variables and ranges in Figure 11, there is a wide variation in possible changes to LCOE caused by inclusion of FOV. The base assumptions represent one possible option among a subset of variables that could determine the option with the most positive economic impact. Further, because FOV represents an option to be exercised in the future, the plant owner will have substantially better information about the range of possible choices and which option is the most viable at the time the option is exercised.

Figure 12 also demonstrates—as shown in Figure 8—that RV and FOV have a greater value when the cost of equity (or discount rate) is lower. Additionally, RV reduces LCOE to a greater degree than FOV, partly due to RV's cash flows coming earlier in the project life and partly due to the greater possibility of additional costs in FOV period in the case of refurbishment or building a new plant.

Viewed from the time of the original investment, FOV for an individual plant depends on intervening events as well as future market conditions. These uncertainties include future fuel and wholesale electricity prices, [36] the time elapsing before refurbishments are required, potential increases in O&M costs, potential shortening of asset life (e.g., due to insufficient ongoing maintenance investment),changes to regulations (e.g., increasing or relaxing the stringency of efficiency or environmental requirements that may result in the retirement of certain technologies or increases in prices along the value chain), and the cost of new components or assets to refurbish the facility. Because of these uncertainties, and the discounts applied to any sufficiently distant revenue, the present value of FOV is typically neglected or heavily discounted for the purposes of investment decisions. This interpretation seems to be consistent with many PPA or LCOE examples, even those that include RV estimates, in which the potential effect of lifetime extensions by refurbishment is typically not mentioned (e.g., Lazard 2016, 2017; BNEF 2016). However, despite the uncertainties, FOV can create positive sources of value while limiting downside risks, without the need to commit capital investment until the refurbishment decision must be made.

As such, the LCOE impact represented in Figure 12 may be too simplistic, because the discount rate on the cash flows associated with committed capital (i.e., initially installed equipment) likely should increase owing to greater uncertainty as the projected timespan increases, however the discount rate on the cash flows of uncommitted capital (i.e., refurbishments) should decrease owing to greater certainty as the project ages closer to that decision. During the initial project financing, when energy is often contracted through a PPA, a project developer may have a lower discount rate than after the contract, because there is less uncertainty over energy value and project performance. It may also be reasonable to assume a lower discount rate for the cash flows of the RV than those of the FOV, because there is more certainty of the project operating over that period and less uncertainty about energy market pricing and the cost of refurbishment. However, any FOV decision occurs later in a project’s life, and the risk does not occur until the investment decision is made.

To adjust for these complications in discount rate, we adjust our analysis, so RV cash flows are discounted at a cost of equity 2% higher than the initial financing period (increasing from 4.5% to 6.5%, or 10% to 12%), and FOV cash flows are discounted at a rate 2% higher than those during the RV period (increasing from 6.5% to 8.5%, or 12% to 14%) in years 31–50. This FOV is then discounted back to present-day dollars at the higher rate if the owner decides to continue operations, but at a rate of inflation (2.5%) if the owner opts to invest new capital (for refurbishment or a new plant). With these adjustments, it is plausible that investors would opt to refurbish the plant in either discount rate scenario. Figure 13 summarizes the results, showing a reduction in LCOE attributed to both RV and continued operations as well as varied results for refurbishment and new plant FOV, depending on discount rate and plant costs.

[36] The characteristics of future markets for grid services—including storage, demand-side management, and ancillary services—are also uncertain and likely to affect the FOV of different technologies asymmetrically.

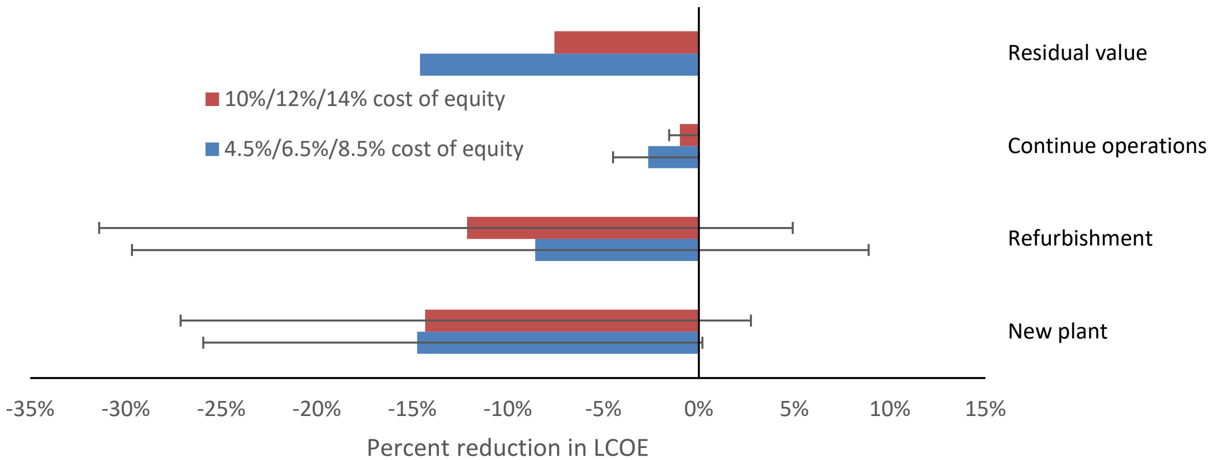


Figure 13. RV and FOV impact on a utility-scale PV plant real LCOE by percentage, with an increasing cost of equity over time

Figure assumes an original financial transaction of 20 years (with a 4.5% or 10% cost of equity), with RV in years 21–30 (with a 6.5% or 12% cost of equity) and FOV in years 31–50 (with a 8.5% and 14% cost of equity). Error bars show the range in value of FOV from the range of assumptions in Figure 11. Rational investors would not typically exercise the options represented in the figure that have a positive change in real LCOE (higher cost).

Although initial investment decisions made by developers, investor-owned utilities, or independent power producers may heavily discount the value of cash flows beyond year 30 (e.g., applying a cost of equity of 10% or more), this discounting may be due to both high uncertainty and high capital cost. Investors such as power authorities and regulated utilities can afford to be strategic: their status and creditworthiness permits them to raise capital less expensively, and on longer time horizons, than other market participants can. As demonstrated in Figure 12, the FOV of a utility-scale PV project with a 4.5% cost of equity (in line with bond raises from public utilities) can in some instances lower LCOE by an additional 14% below the LCOE with RV. This analysis may underestimate FOV, because FOV represents the option an asset owner has at various points in time to make a wider range of choices that will only be exercised under circumstances in which it makes financial sense. Owing to the option's value in delaying certain investment decisions (and hence the use of capital) until more information is available as well as the asymmetrical relationship of the risks (no downside, only upside), the variety of risks and unknowns, and the range of different refurbishment options, timing and contractual terms, and their interrelationship, a real options-based analysis may be a more appropriate method of describing FOV.

Examples of Refurbishment

Although there may be significant risk and uncertainty associated with future refurbishment costs of specific generating assets, some of this risk may be diversifiable and may be partially mitigated through a portfolio perspective, as done by the Bonneville Power Administration (BPA). Hydroelectric plants can be very long-lived (see Section 3), providing substantial value over their lives. For example, BPA operates a 22-GW system of 31 federally-owned hydroelectric dams in the Pacific Northwest, with an average asset life of more than 50 years.

BPA's future plans assume 75 or more years of future operation at an annualized capacity-adjusted cost of roughly $30/kW-year (BPA 2013, 2014). Such costs make continuing operation extremely attractive today compared with investment in new generation, particularly considering the low O&M and negligible fuel costs of hydroelectric generation. In addition, refurbishment means investors can defer retirement costs, such as restoring the land to its original condition. This refurbishment to continue operations option may also offer other benefits to plant owners, compared to building a new plant at a new site, including access to, or ownership of, the land and use of the auxiliary electrical equipment associated with the site, such as the equipment for sending power to the transmission system and the transmission system itself.

Although the value of plants and the cost of refurbishment will vary, there are many examples of investors choosing to extend asset lives and increasing capacity, as discussed in Text Box 1.

Box 1. Extending asset life through retrofits

Minor or major retrofits may provide a cost-effective way of extending plant life while improving efficiency and/or adding capacity (i.e., uprating or repowering). Because the range and timing of refurbishment, uprate, and repower options is so wide—and because generation technologies and systems vary substantially—it is difficult to generalize what will happen after the first 20, 30, or 40 years of plant life. Nevertheless, historical evidence suggests that life-extending and performance-enhancing retrofits are common. Examples include:

- **Hydro plant repowered and uprated.** Repowering a hydroelectric plant may not only extend the operational life, but also increase its nameplate capacity. For example, between 1986 and 1993, turbines at the Hoover Dam were replaced and uprated from 82.5 MW to 130 MW, increasing the nameplate capacity by more than 50%, from 1,344 MW to 2,080 MW (DOE 2016). More recently the nameplate capacity at Hoover has fallen in recent years because of a significant reduction in the water elevation (and hence available potential energy for any given turbine) of Lake Mead, stored behind the dam. This decreased water level has led to a separate refurbish program to install wide-head turbines and other modifications that improve turbine efficiency at lower water levels (Walton 2016).
- **Thermal plant repowering.** The design life of the rotor (which provides the magnetic field for a synchronous generator) is 30 years,[37] although it will be shorter if subject to frequent starting, stopping, and ramping. As General Electric (GE) notes, "Experience has shown the rotor to be the generator component requiring the most maintenance." Refurbishment choices near the end of the "original" rotor life can include rewinds or replacements depending on the future anticipated life of the plant. For example, when both the rotor and stator are rewound, nameplate output capacity can increase by as much as 35% (Zawoysky and Tornroos 2008).
- **30-year-old steam plant converted to CCGT.** A 640-MW gas-fired steam generating unit, which came online in 1977–1978 (Essant, Holland) was repowered in 2008 to become a 1,300-MW CCGT with efficiency increased from 38% to 58%. This involved adding three gas turbines and heat-recovery steam generators and retrofitting the existing steam turbine. The refurbishment cost 15%–20% less than a new CCGT (Hitchin 2011). As the owner noted, "Large section[s] of the existing steam turbine building and electrical building, and the direct cooling facilities – such as the main cooling water pumps and the cooling tower – were reused, as was the condenser."
- **Fossil fuel plant retrofitted to meet compliance standards and extend life.** In 2010, a contract was signed to retrofit six 380-MW units (PGE Elektrownia Belchatow, Poland) to increase output of each unit by 20 MW (or 5%), increase efficiency by 2.4%, and "support the extension of the life by 25 years," which would extend the life of plants built between 1982 and 1988 to around 50 years (Hitchin 2011).
- **50-year-old coal thermal plant converted to natural gas.** Old, inefficient coal thermal plants can be switched directly to natural gas, as an alternative to CCGT. For example, two of three coal-fired generating units at Appalachian Power's Clinch River Power Plant built around 1960 are being converted, with the steam boiler switched to combust natural gas rather than pulverized coal (Hitchin 2011). Appalachian's parent American Electric Power noted that converting these 57-year-old plants in this way was "identified as the least-cost alternative to meeting customers' power needs and supporting the local economy while reducing the plant's emissions. Activities are

[37] Frequent ramping will shorten rotor life because of greater mechanical wear and tear, including the stress-related effects of high "g-forces" that arise when the rotor is accelerated at high speed.

under way at Units 1 and 2 to install equipment and systems to deliver, handle and burn natural gas (while) ⋯ existing burners were modified" (AEP n.d.). In this case, the third generating unit was retired.

- **Pump storage life extended.** A 90-year-old, 140-MW pumped storage plant (Waldeck 1) was refurbished between 2004 and 2009 at a cost of 50 million Euros, or about $500/kW. The 42-year-old Waldeck 2 was refurbished with an increase in capacity from 440 to 480 MW for 30 million Euros, or about $1,000/kW for the incremental 40 MW and only about $100/kW on average for keeping the existing and the new 480-MW plant running for another 50 years (Hitchin 2011). In contrast, estimates for new pumped hydro facilities are typically $2,000/kW or more (Deane et al. 2010). Deane et al. (2010) also note that "trends for new PHES [pumped hydro energy storage] development generally show that developers operating in liberalized markets are tending to repower, enhance projects or build 'pump-back' PHES rather than traditional 'pure pumped storage.'"
- **Nuclear plant uprated.** Two nuclear plants that started operating in 1971 and 1983 were uprated from 2,729 MWt to 2,947 MWt to provide 70-MWe uprates (an 8% increase in output) for each reactor at a cost of $50 million (Hitchin 2011), representing an incremental cost of less than $400/kW and less than $40/kW for life extension of existing capacity.

Repowering is also increasingly important for renewable energy. For example, GE suggests that repowering—which can include increasing a wind turbine's rotor size and upgrading the gearbox, hub, main shaft, and main bearing assembly—"extends the life of onshore wind turbines by a decade or more, making turbines more efficient and reliable … and can increase fleet output by 25% and add an additional 20 years to turbine life from the time of the repower" (GE 2017). There are additional signs that the market potential for wind repowering may be significant:

- Among the oldest U.S. wind farms, 20 or more small turbines may be replaced by a single, more productive turbine. Nearly 10% of U.S. wind turbines are more than 20 years old, yet such turbines represent only 1% of U.S. wind capacity. EIA (2017d) notes, "MidAmerican Energy recently awarded a contract to GE Renewable Energy to repower as many as 706 older turbines at several wind farms in Iowa. After repowering, each turbine is expected to generate between 19% and 28% more electricity." Altamont Pass in California, with nameplate capacity of 500 MW built in the 1980s, comprised over 5,000 small turbines.
- There have been several agreements to expand nameplate capacity by replacing existing turbines with much larger ones. NextEra replaced 440 operating wind turbines with 34 Siemens 2.3-MW wind turbines; this entailed removal of "286 foundations of non-operating sites, 180 power poles and more than 6.5 miles of overhead power lines" (NextEra 2015). More recently, a project announced by Salka in 2017 will repower a former Altamont Pass wind farm by replacing 569 100-kW wind turbines with 27 modern turbines with a combined capacity of 55 MW. The project is expected to generate more than 60% of its power during peak hours (Froese 2017).

5.2 System Modeling

System modelers often use capacity-expansion models to estimate the future evolution of the electricity system, simulating new investments and retirements to meet future load in a least-cost manner. These models typically use financial lifetimes to estimate the attractiveness of investment options for capacity expansion. The choice of financial lifetime for capital recovery and its application to investment and operational decisions for different technologies may vary between models and modelers. For example, EIA uses 30 years as the financial life for capital recovery of original investment for investment decisions for nearly all technologies. EIA employs one of the relatively few models that takes refurbishment into account by using an annualized technology-dependent capital recovery added until the plant retires; retirement is driven by economic considerations. More generally, some analysts use common lifetimes that are shorter, while others may use both longer and shorter lifetimes that are more closely linked to the estimated operational life of different technologies.

Owing to the shorter financial time horizons of many investors, many energy plants recoup investors' financing costs well before the end of their actual operational life that may include refurbishments. This is exemplified in many capacity-expansion models that make investment decisions based on full capital recovery after 20–30 years, but often then allow these generation assets to continue to operate for additional decades at much lower costs.[38] Such a model representation of the longer-term economic value of generation assets is partially supported by the distribution of much longer retirement ages and fleet lifetimes (see Figure 3, Figure 5, and below). However, unlike EIA, some modelers may overestimate near-terms costs (by using a short term for full capital recovery) and underestimate longer-term costs associated with refurbishments.

Figure 14 shows the LCOE for different technologies based on 30-year capital recovery, compared with the ongoing LCOE after year 30. For illustrative purposes, ongoing fixed costs for plants that are currently 30 years old are estimated at 20% of the capital investment for current replacement technology. As the figure shows, ongoing LCOEs starting in year 30 are much lower than LCOEs for new investments made at the same time and thus have a higher annualized economic value relative to market electricity prices (illustrated by the lines at $20 and $60/MWh).[39]

[38] Continued operation may also be broadly consistent with treatment of electricity generation cost in a regulated market, although in part this will depend on how refurbishment options and associated capital costs are treated.
[39] The analysis described here may underestimate the actual FOV, because in nominal terms any remaining capital recovery associated with the original investment could be discounted by 40% or more owing to the effects of inflation, although the difference might be partly offset by technology cost and performance improvements over time. The idea that older assets have lower annual capital recovery costs because of the impact of inflation has been discussed in detail by Stacy and Taylor (2015). There may also be an underestimate due to the range of low-cost options to extend plant life, increase capacity, or both (see Box 1).

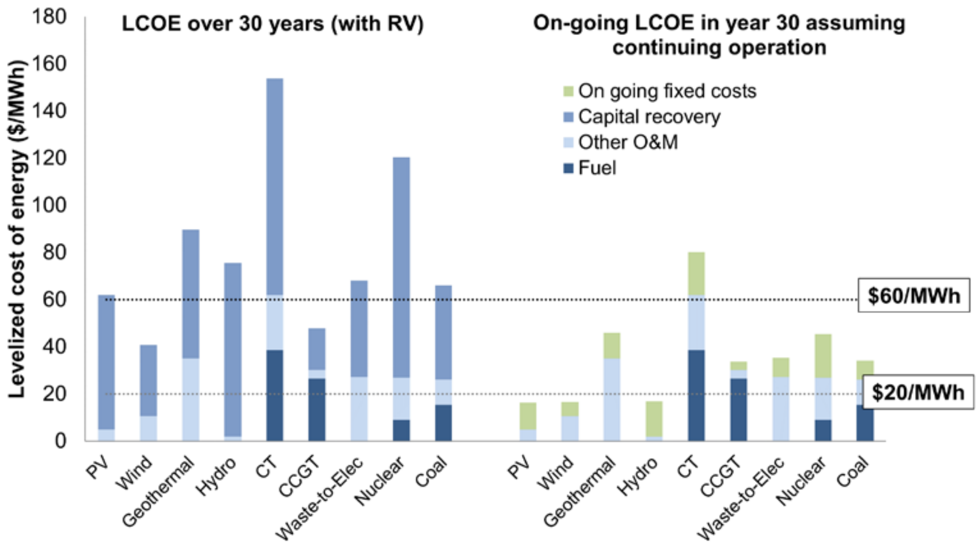


Figure 14. LCOE for various new generation technologies calculated over 30 years (left) compared with LCOE for existing plants assuming ongoing operation in year 30 (right).

The ongoing annualized fixed costs associated with annualized capital recovery of refurbishments and are assumed to be based 20% of the full replacement new technology costs for illustrative purposes. Source: Capital and operating costs for these technologies are consistent with the range of estimates given by Lazard (2017) and EIA (2017b).

Minor or major refurbishments, such as replacing generator current windings (rewinding) with or without uprating, may be more attractive than ongoing operations on an NPV basis, particularly as newer technologies or increasing O&M exert competitive pressure. Hitchin (2011), for example, notes when comparing the options of new investments to upgrading existing plants, "Where the option exists, upgrading existing plant can enhance plant lifetime, improve efficiency and give increased output for a fraction of the cost of building new plant" (see also Box 1). On a cautionary note, any prediction about the electricity sector in 2050 is uncertain, and these uncertainties are heightened by present changes in energy technology and policy, and the growing role of PV and wind.

The use of a common operational life approach that ignores FOV in the original investment decision may bias LCOE calculations and investment decisions against technologies with much longer lifetimes, particularly capital-intensive generation assets such as hydroelectric or plants employing steam-based Rankine cycles (e.g., coal, natural gas, nuclear, or solar thermal). Without further modifications, such a common-life approach will not reflect incremental benefits of technological advances that extend the life of the asset by 5 or 10 years or more, such as repowering with larger wind turbines or using more efficient PV modules after 30–40 years. The impact of such methodological choices may:

- Bias investments against technologies with higher capital requirements and long lives
- Imply higher consumer costs
- Front-load capital recovery and charge consumers unevenly over a generator's life, which can discourage investment or lead to excess payments for a given level of reliability.

The impact of RV and FOV on returns to generators depends on market structure and other assumptions,[40] and the impact on consumer costs is less clear.[41]

6 Discussion and Conclusions

Our findings suggest that the realized operational lives of electricity generation assets are often longer than estimates and much longer than those specified in original financial contracts, although the difference varies by technology. And, we identify RV and FOV as concepts that can be used by the industry to demonstrate additional value from electricity-generating assets. For coal and natural gas steam turbine driven plants, lifetimes of 50 to 60 years or more have been common. For hydroelectric plants, lifetimes of 75 to 100 years or more have been achieved. Although the expected operational lives for variable renewable energy technologies (e.g., wind and PV) are shorter and fewer data are available for them owing to the relative newness of these technologies, recent evidence of rapid technological improvement and the potential for cost-effective repowering and other upgrades suggest longer lives than may have been originally expected. Moreover, because of advances in system integration and the rapid reduction in battery costs these systems could continue to be economical even with higher levels of penetration.

The report includes the following specific findings:

- **The realized operational lives of generation technologies before retirement are typically much longer than typical measures of financial lives.** Typical PPA contracts, expectations of capital recovery, and even estimates of likely operational lives of conventional generation assets have often been lower than their historical operational lives, many of which are 50 years of age or more. Additionally, based on decades of study and operational experience, the plant lifetimes for PV and wind are in the range of 25 to 35 years, but total lifetimes are viewed as less certain than the lifetimes of incumbent technologies.
- **Including an RV estimate in investor returns can reduce initial electricity prices so that electricity sold by a new generation asset is more competitive in the near term.** The impact of RV on lowering LCOE can be comparable to the impact of other factors considered for generation investment decisions. Including RV for certain technologies may also help provide a more complete and accurate assessment across all technology options.
- **Refurbishment has a useful and economic role but is often neglected during initial investment.** Extending the life of thermal or hydroelectric generation assets typically requires minor or major upgrades, but the cost of such extensions—which may include increased nameplate capacity—has often been much more attractive on a present-value basis than the alternative of complete replacement with the same technology or a different technology. Therefore, investing in technologies with the ability to be refurbished or upgraded provides the value of the option to do so. Similar considerations may increasingly apply to both PV and wind in the future.

[40] This analysis and most capacity-expansion models describe future least system cost cases similarly to regulated cost-plus electricity markets. For other market situations, the expansion/retirement estimates of such models are less robust.
[41] Such costs may vary substantially by choice of rules, for capacity and other payments, particularly in scenarios where some generation technologies have operational lives of 50 years or more. This is an area for future research.

- **Increasing RV through life extension without refurbishment has an LCOE impact.** If the operational lifetime is extended—for example, from 20 to 30 years, or from 30 to 40 years—the difference in LCOE represents an increase in present value, and it may lower the price of energy over any given period.[42] This suggests that research and development as well as commercial efforts to extend the life of wind or PV, as well as most generation technologies both renewable and conventional, even before the first refurbishment option, may be very valuable.
- **Estimating FOV at the time of original investment is complex and often neglected, but it may be valuable if a practical estimation method is developed.** For a plant approaching the end of its expected operating life, the method for deciding whether to retire or refurbish is relatively straightforward in principle. However, estimating the present value of FOV at the time of the original investment is far more complex because of the wide range of types and timing of different follow-on options and the lack of information about the likelihood or present value of such options at the time of investment. On the other hand, the existence of FOV among existing plants that are 30 years old or older suggests such value is widespread and substantive even though it may be uncertain.

Our results also raise the question of whether and how FOV might be better valued at the time of investment and by whom, including possible "end-of-life" arrangements or options that might transfer or swap ownership while retaining operating and/or offtake contracts. Many uncertainties exist that far into the future. However, many decisions about a plant—such as refurbishment—are made in the future, and this investment option may have value, given its history of lengthening energy asset lives, particularly given that future investments, if any, are not committed upfront. Large companies, public entities, pooling structures, or others may seek benefits that a portfolio of such assets could build. Government-owned hydroelectric facilities, such as those run by BPA, and municipality-owned waste-to-electricity plants are examples of assets that provide low-cost power over long lifetimes under contractual arrangements attractive to asset owners and operators. Parties from the private or public sectors, such as capital funds with long-term investment horizons and university endowment funds, might find such assets align with their long-term goals.

Understanding and properly incorporating such issues is important not only to investors, but also to analysts and modelers who construct future system scenarios using capacity-expansion models. For example, a decision to require capital recovery over common timeframes of 30 years or less may bias investments against generators with longer lives and higher capital costs while failing to reflect benefits associated with incremental increases in expected operational lives. This can occur even when present-value calculations are technically correct, particularly given the wide range of lower-cost refurbishment options that may be available near the end of the original design life, including asymmetric benefits arising from scaled expansion both during and toward the end of the original asset life.

[42] In this case, if the price of power is not changed, the NPV increases. Alternatively, the price can now be lowered to achieve the same NPV for the investor.

Our analysis also suggests potential future work. For example, it may be useful to continue tracking and to publish broader data sets on asset life and contract prices, including the timing of refurbishments choices and retirements by technology. Likewise, documenting additional cases of repowering may be useful to those quantifying costs and benefits and to those trying to gain a better understanding of the frequency, time, variety, and cost of different refurbishment options by technology. This approach could be extended to better address some of these questions using real options in analyzing follow-on investment and assessing the advantages and limitations the analysis would entail. Further sensitivity analysis may also be helpful, to further understand how RV compares to other economic or policy effects in lowering LCOE for renewables. Likewise, it may be interesting to know how the inclusion of RV, and its corresponding effects on LCOE and revenue requirement calculations, affect the investments and expansion predicted in power sector models. It may also be useful to perform a more robust sensitivity analysis exploring the degree to which various uncertainties affect RV and FOV, including future fuel and wholesale electricity prices, the time elapsed before refurbishments are required, potential increases in O&M costs, potential shortening of asset life, changes to environmental or other regulations, and the cost of new components or assets to refurbish the facility.

The longer operational lives realized by today's generation fleet reflect the availability and use of retrofitting options that can extend plant life, increase capacity, or both. Such retrofits often provide an economically attractive alternative to new generation. When making investment decisions before or during an asset's lifespan, it is useful to account for both nearer-term RV and FOV that might involve minor or major refurbishment. In practice, it is less common to include FOV in original investment decisions. However, the existence of long-lived generation assets suggests the possibility of developing strategies to realize such future value, which might enable investment decisions to consider longer-term aims.

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