NATIONAL ENERGY TECHNOLOGY LABORATORY

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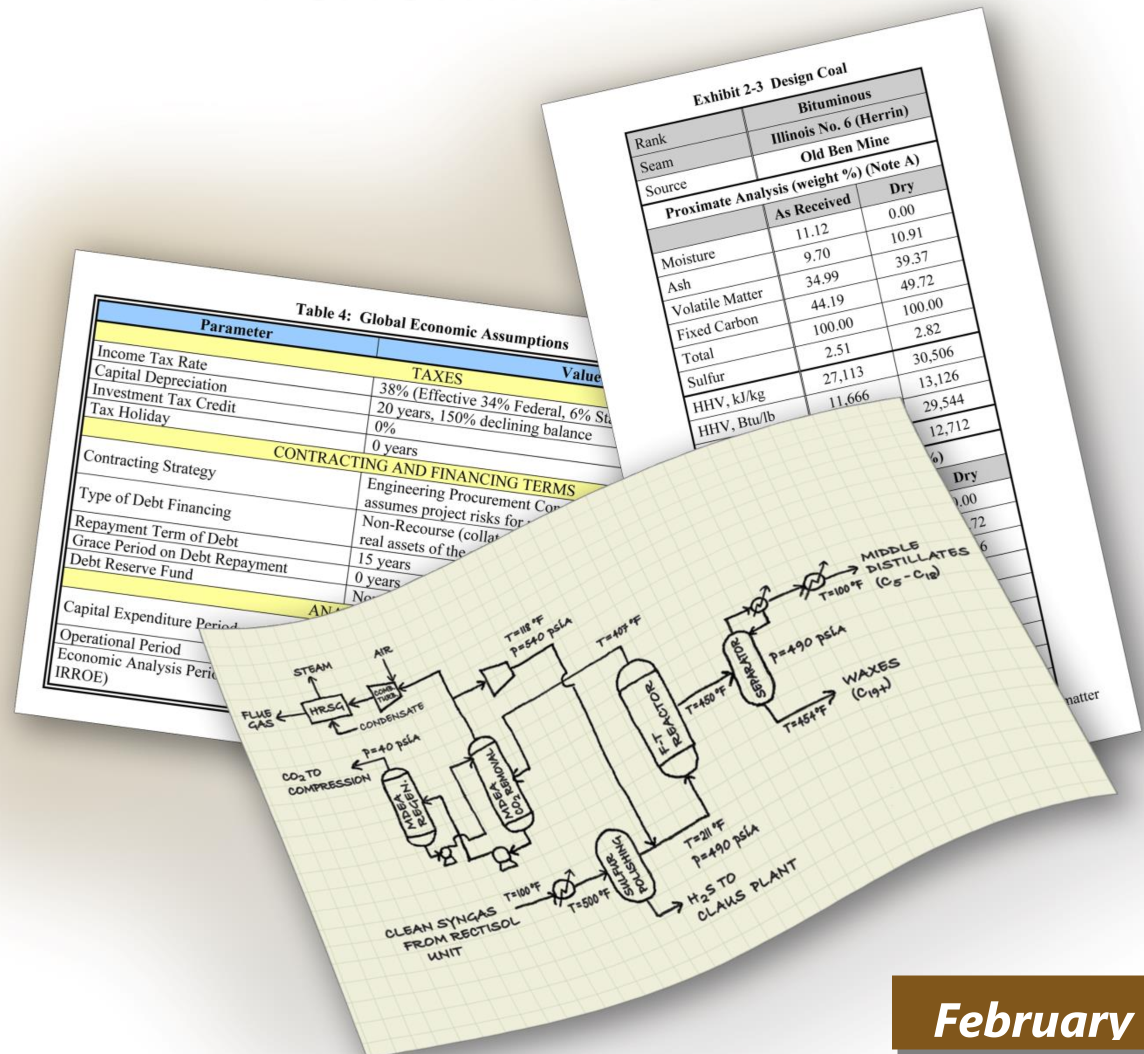
QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Cost Estimation Methodology for NETL Assessments of Power Plant Performance



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Errata

This report is a re-issue of the 2019 study (published on September 2019), revised as follows:

1) Exhibit B-2: for TASC/TOC factors, updated the Commercial IOU value for the 3-year construction period vs. Revision 4 TASC/TOC from 1.092 to 1.093.
2) Exhibit B-3: for Capital Component factors, updated the Commercial IOU value for the 3-year construction period vs. Revision 4 FCR from 0.0721 to 0.0707.
3) Exhibit B-3: for Capital Component factors, updated the Commercial IOU value for the 3-year construction period vs. Revision 4 FCR*TASC/TOC from 0.0788 to 0.0773.
4) Exhibit B-3: for Capital Component factors, updated the Commercial IOU value for the 3-year construction period vs. % decrease from 25%-29% to 26%-30%.
5) Exhibit B-3: for Capital Component factors, updated the Commercial IOU value for the 5-year construction period vs. Revision 4 FCR from 0.0729 to 0.0707.
6) Exhibit B-3: for Capital Component factors, updated the Commercial IOU value for the 5-year construction period vs. Revision 4 FCR*TASC/TOC from 0.0841 to 0.0817.
7) Exhibit B-3: for Capital Component factors, updated the Commercial IOU value for the 5-year construction period vs. % decrease from 27%-32% to 29%-34%.

Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance

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List of Exhibits

Acronyms and Abbreviations

AACE	Association for the Advancement of Cost Engineering
AFUDC	Allowance for funds used during construction
AOM	Annual O&M expenses
ATWACC	After-tax weighted average cost of capital
BEC	Bare erected cost
CAPM	Capital Asset Pricing Model
CCF	Capital charge factor
CCS	Carbon capture and storage
CO_2	Carbon dioxide
COE	Cost of electricity
CRF	Capital recovery factor
DOE	Department of Energy
EEI	Edison Electric Institute
EPC	Engineering, procurement, and construction
EPCC	Engineering, procurement, and construction cost
EPCM	Engineering, procurement, and construction management
EPRI	Electric Power Research Institute
ETR	Effective tax rate
FCR	Fixed charge rate
FEED	Front-End Engineering Design
GDP	Gross domestic product
IDC	Interest during construction
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
IRR	Internal rate of return
LCC	Levelized capital cost
LCOE	Levelized cost of electricity
LFP	Levelized annual fuel expenses
LOM	Levelized O&M costs
MWh	Megawatt hour
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
O&M	Operation and maintenance
PC	Pulverized coal
P_n	Fuel price in year n
PSFM-GT	Power systems financial model for grid technologies
q	Subscript designating nominal value
QGESS	Quality Guidelines for Energy System Studies
r	Subscript designating real value
ROE	Return on equity
SEA	Systems Engineering & Analysis
T&S	CO_2 transport and storage
TAG®	Technical Assessment Guide
TASC	Total as-spent capital
TCM	Total cost management
TOC	Total overnight cost
TPC	Total plant cost
WACC	Weighted average cost of capital
$/kW	Dollars per kilowatt
$/MWh	Dollars per megawatt hour

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1 Introduction

This paper summarizes the methodology employed by the National Energy Technology Laboratory (NETL) in calculating power plant costs in its techno-economic studies, such as the Cost and Performance Baseline for Fossil Energy Systems series of reports. It also outlines the approach used to calculate the cost of electricity by which NETL evaluates electric power plants. These metrics and a clear understanding of the methodology used are essential in allowing different power plant technologies to be compared on a similar basis. These guidelines are tailored for power producing plants, although they can be applied to a variety of different revenue generating plants (e.g., coal to liquids, syngas generation, hydrogen).

2 Capital Costs

2.1 Levels of Capital Costs

As illustrated by Exhibit 2-1, there are five levels of capital costs to consider in constructing a power plant. The levels are defined as the following:

<u>Bare Erected Cost</u> (BEC) comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. Equipment cost estimates are frequently developed for each plant or plant component using in-house database and conceptual estimating models for specific technologies and may differ from values generated by other software packages such as Aspentech's Aspen Economic Analyzer.

<u>Engineering, Procurement, and Construction Cost</u> (EPCC) comprises the BEC plus the cost of services provided by the EPC contractor. The EPC services include detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs.

<u>Total Plant Cost</u> (TPC) comprises the EPCC cost plus project and process contingencies.

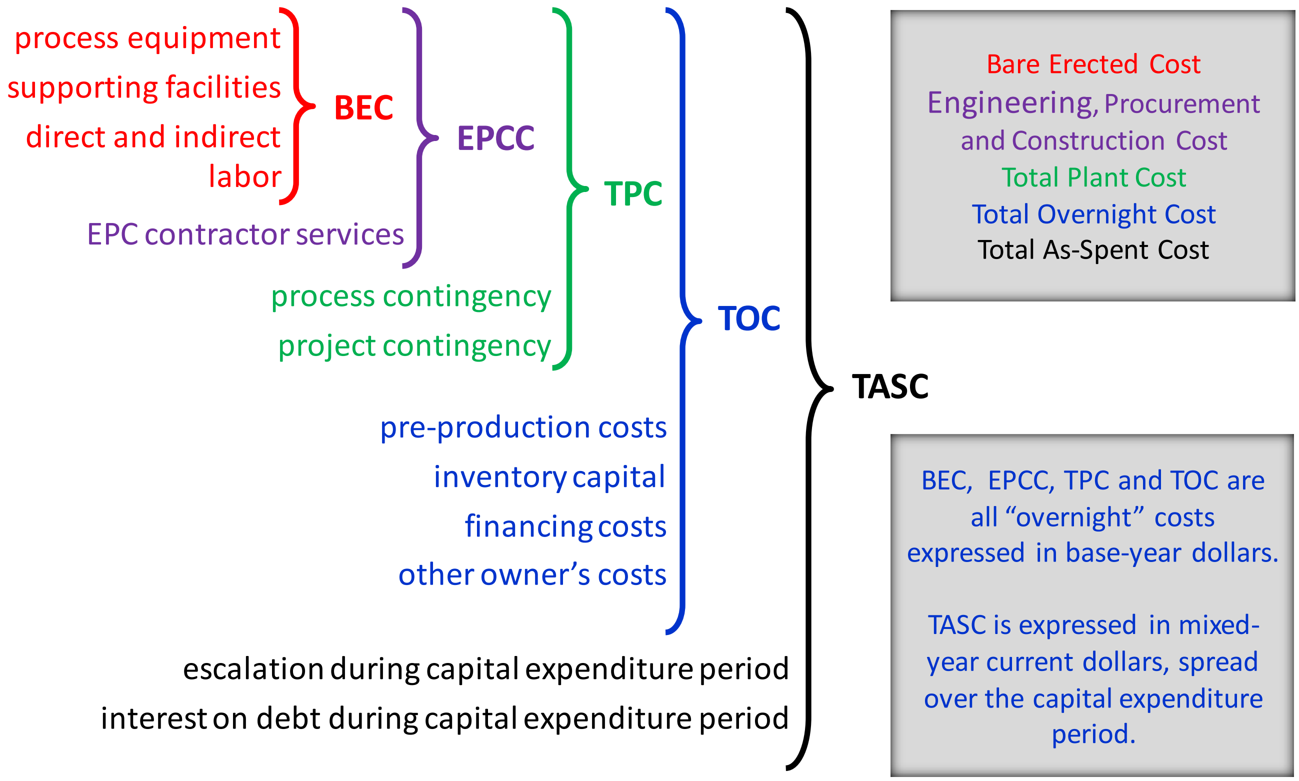
<u>Total Overnight Capital</u> (TOC) comprises the TPC plus all other "overnight" costs, including owner's costs. TOC is an overnight cost, expressed in base-year dollars and as such does not include escalation during construction or construction financing costs.

<u>Total As-Spent Capital</u> (TASC) comprises the sum of all capital expenditures as they are incurred during the capital expenditure period for construction including their escalation. TASC also includes interest during construction, comprised of interest on debt and a return on equity (ROE). TASC is expressed in mixed, current-year dollars over the capital expenditure period.

BEC, EPCC, TPC, and TOC are overnight costs and are expressed in base-year dollars. The base year is the year in which all technology costs are expressed for the comparison of technologies from a standard starting point. TASC is expressed in mixed, current-year dollars over the entire capital expenditure period, which is assumed in most NETL studies to last five years for coal plants and three years for natural gas plants.

If one wants to portray all plants in real dollars, the base year typically is used for the real dollar year. Since real dollars exclude inflation, the LCOE is calculated by adding the real levelized capital costs to the operation and maintenance (O&M) costs expressed in real levelized $/MWh plus the fuel costs expressed in real levelized $/MWh. The formulas for these calculations are in Section 3 of this paper.

Exhibit 2-1. Capital cost levels and their elements



2.2 Cost Estimate Classification

Recommended Practice 18R-97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in engineering, procurement, and construction (EPC) for the process industries. [1] Most engineering-economic studies completed by NETL feature cost estimates intended for the purpose of a "Feasibility Study" (AACE Class 4) or "Concept Screening" (AACE Class 5), commensurate with the maturity of the technologies under evaluation, recent commercial experience, nature of available cost data, and other factors. Exhibit 2-2 describes the characteristics of AACE Class 4 and Class 5 cost estimates. Each NETL study typically specifies the accuracy range of its cost estimates. For example, recent NETL studies [2] characterize PC and NGCC case estimates as falling within AACE Class 4. Given recent experience with NGCC plants, the NGCC uncertainty range (-15 percent/+25 percent) is slightly smaller than PC (-15 percent /+30 percent). Integrated gasification combined cycle (IGCC) estimates are presented within Class 5, with a larger uncertainty range (+25 percent /+50 percent), consistent with the above considerations for this classification.

Exhibit 2-2. Features of an AACE Class 4 and Class 5 cost estimates

Project Definition	Typical Engineering Completed	Expected Accuracy
1 to 15%	• Plant capacity, block schematics, indicated layout, process flow diagrams for main process • Systems and preliminary engineered process and utility • Equipment lists	**Class 4** -15% to +30%
0 to 2%	• Cost estimates (i.e., feasibility study) based on the level of engineering design performed • This range is deemed reflective of recent commercial power IGCC experience	**Class 5** -25% to +50%

2.3 Contracting Strategy and EPC Contractor Services

The cost estimates are based on an engineering, procurement and construction management (EPCM) contracting strategy utilizing multiple subcontracts. This approach provides the owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in an EPC contract price. In a traditional lump sum EPC contract, the contractor assumes all risk for performance, schedule, and cost. However, as a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. Rather, the current trend appears to be a modified EPC approach where much of the risk remains with the owner. Where contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

The EPCM approach used as the basis for the estimates is anticipated to be the most cost-effective approach for the owner. While the owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

The EPCM contractor services are estimated at 15 to 20 percent of BEC, depending on the technology considered. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, a resident engineer, a scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

2.4 Estimation of Capital Cost Contingencies

Process and project contingencies are included in estimates to account for anticipated but unspecified costs due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared.

Capital cost contingencies do not cover uncertainties or risks associated with:

- Scope changes
- Changes in labor availability or productivity
- Delays in equipment deliveries

- Changes in regulatory requirements
- Unexpected cost escalation
- Performance of the plant after startup (e.g., availability, efficiency)

Process Contingency

Process contingency is intended to compensate for uncertainty in cost estimates caused by performance uncertainties associated with the development status of a technology. Process contingencies are applied to each plant section based on its current technology status. Process contingency is typically not applied to costs that are set equal to a research goal or programmatic target since these values are generally intended to reflect the total cost.

As shown in Exhibit 2-3, AACE 16R-90 provides guidelines for estimating process contingency. [3]

Exhibit 2-3. AACE guidelines for process contingency

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

Project Contingency

AACE 16R-90 states that project contingency for a “budget-type” estimate (AACE Class 4 or 5) should be 15 percent to 30 percent of the sum of BEC, EPC fees, and process contingency. [3]

2.5 Estimation of Owner’s Costs

With some exceptions, the estimation of owner’s costs method follows guidelines in Sections 12.4.7 to 12.4.12 of “Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries,” AACE 16R-90. [3] The Electric Power Research Institute’s (EPRI) “Technical Assessment Guide (TAG®) – Power Generation and Storage Technology Options” also has guidelines for estimating owner’s costs. [4] EPRI and AACE guidelines are very similar. Because the owner’s costs could be assumed to be as high as 20 percent of the TPC, which includes contingency costs, failure to understand what could be included can lead to an unwarranted cost estimate. Exhibit 2-4 provides some of the items that can be included in owner’s costs.

Exhibit 2-4. Estimated amounts for owner's costs

Owner's Cost	Estimate Basis
Prepaid Royalties	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.
Preproduction (Start-Up) Costs	• 6 months operating labor • 1 month maintenance materials at full capacity • 1 month non-fuel consumables at full capacity • 1 month waste disposal • 25% of one month's fuel cost at full capacity • 2% of TPC Compared to AACE 16R-90, this includes additional costs for operating labor (6 months versus 1 month) to cover the cost of training the plant operators, including their participation in startup, and involving them occasionally during the design and construction. AACE 16R-90 [3] and EPRI TAG® [4] differ on the amount of fuel cost to include; this estimate follows EPRI.
Working Capital	Although inventory capital (see below) is accounted for, no additional costs are included for working capital.
Inventory Capital	• 0.5% of TPC for spare parts • 60-day supply (at full capacity) of fuel. Not applicable for natural gas • 60-day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. Does not include catalysts and adsorbents that are batch replacements such as water gas shift, carbonyl sulfide, and selective catalytic reduction catalysts and activated carbon AACE 16R-90 [3] does not include an inventory cost for fuel, but EPRI TAG® [4] does.
Land	• $3,000/acre (300 acres for IGCC and PC, 100 acres for NGCC) • Note: This land cost is based on a site in a rural location
Financing Cost	• 2.7% of TPC This financing cost (not included by AACE 16R-90 [3]) covers the cost of securing financing, including fees and closing costs but not including interest during construction (or AFUDC). The "rule of thumb" estimate (2.7% of TPC) is based on a 2019 professional communication with Black & Veatch.
Other Owner's Costs	• 15% of TPC This additional lumped cost is not included by AACE 16R-90 [3] or EPRI TAG® [4]. The "rule of thumb" estimate (15% of TPC) is based on a 2019 professional communication with Black & Veatch. The lumped cost includes ○ Preliminary feasibility studies, including a Front-End Engineering Design (FEED) study ○ Economic development (costs for incentivizing local collaboration and support) ○ Construction and/or improvement of roads and/or railroad spurs outside of site boundary ○ Legal fees ○ Permitting costs ○ Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors) ○ Owner's contingency (sometimes called "management reserve"—these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of a five-day/ten-hour-per-day work week. Owner's contingency is not a part of project contingency) This lumped cost does not include ○ EPC risk premiums (costs estimates are based on an EPCM approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost) ○ Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar ○ Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes ○ Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations

2.6 Other Costs

When estimating the COE or LCOE for a power plant, it might not be feasible to identify every single item because of the uncertainty of what will be required and changes in the construction as the plant is built. There are some items outside the fence of the plant; the plant boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system, but terminating at the high voltage side of the main power transformers. The only cost outside of this fence line that is accounted for is the cost of CO_2 transport and storage (T&S). For plants using with carbon capture and storage (CCS), the T&S costs are reported separately from the plant capital and O&M costs.

Some typical examples of items outside the fence line include

- New access roads and railroad tracks
- Upgrades to existing roads to accommodate increased traffic
- Makeup water pipe outside the "fence line"
- Landfill for on-site waste (slag) disposal
- Natural gas line for backup fuel provisions
- Plant switchyard
- Electrical transmission lines and substation

All estimates are based on a reasonably standard plant. No unusual or extraordinary process equipment is included such as

- Excessive water treatment equipment
- Air-cooled condensers
- Automated coal reclamation

Other items that are not addressed in the cost estimates are

- Piles or caissons
- Rock removal
- Excessive dewatering
- Expansive soil considerations
- Excessive seismic considerations
- Extreme temperature considerations
- Hazardous or contaminated soils
- Demolition or relocation of existing structures
- Leasing of offsite land for parking or laydown
- Busing of craft to site
- Costs of offsite storage

To the extent that these items are needed at specific sites, they should be explicitly included within the capital cost structure, rather than as part of the contingency costs.

3 Economic Assumptions for COE and LCOE

3.1 Global Economic Assumptions

Global economic assumptions for NETL's cost analyses are listed in Exhibit 3-1. Deviations may be explicitly justified on a case-by-case basis.

Exhibit 3-1. Global economic assumptions

Parameter	Value
TAXES	
Income Tax Rates	21% federal, 6% state (Effective tax rate [ETR} 25.74%)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
CONTRACTING AND FINANCING TERMS	
Contracting Strategy	Engineering Procurement Construction Management (owner assumes project risks for performance, schedule, and cost)
Type of Debt Financing	Non-recourse (collateral that secures debt is limited to the real assets of the project)
Repayment Term of Debt	Equal to operational period in formula method
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
ANALYSIS TIME PERIODS	
Capital Expenditure Period	Natural gas plants: 3 years Coal plants: 5 years
Operational Period	30 years
Economic Analysis Period	33 or 35 years (capital expenditure period plus operational period)
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Capital Expenditure Period	0% real (3% nominal [5])
Distribution of Total Overnight Capital over the Capital Expenditure (before escalation)	3-year period: 10%, 60%, 30% 5-year period: 10%, 30%, 25%, 20%, 15%
Working Capital	Zero for all parameters
% of Total Overnight Capital that is Depreciated	100% (actual amounts are likely lower, and do not influence results significantly)
ESCALATION OF OPERATING COSTS AND REVENUES	
Escalation of COE (revenue), O&M Costs	0% real (3% nominal [5])
Fuel Costs	See Quality Guidelines for Energy Systems Studies Fuel Prices for Selected Feedstocks in NETL Studies [6]

3.2 Finance Structures

When a new project is being financed and constructed, a finance structure is developed specific to the market conditions and the ownership risks. The cost analyses performed by NETL are for both near-term construction of commercial technologies, with 2023 as the on-line year, as well as for advanced technologies, which are typically assumed to be commercial 15 years or more into the future. For the purpose of comparing technologies in the NETL Baseline study [2], the same finance structure will be applied to all scenarios, and only real dollars are used. When these technologies are evaluated in various cash flow analyses, nominal dollars will be used. All technologies are considered to be commercial ready – there are neither applicable tax subsidies nor risks associated with first-of-a-kind construction or immature design.

Statistics on the returns earned by well-established companies, whether in an unregulated or regulated market, suggest that there is little difference in ROEs.[1] Therefore, the structure chosen for developing the financing for major power projects is that of a large, financially-stable, investor-owned utility (IOU) or merchant plant. Any other type of builder is assumed to have a higher cost financial structure, and therefore would be non-competitive.

Exhibit 3-2 shows the finance structure that would apply to all types of power plants on a nominal basis and also in real terms for nth-of-a-kind level of market penetration.

Exhibit 3-2. Nominal and real rates financial structure for investor-owned utility

Type of Security	% of Total	Current Dollar Cost	Weighted Average Cost of Capital	After-Tax Weighted Average Cost of Capital
Nominal				
Debt	55%	5%	2.75%	2.04%
Equity	45%	10%	4.50%	4.50%
Total			7.25%	6.54%
Real (based on 2.01% average real GDP deflator, 1990-2018 [7])				
Debt	55%	2.94%	1.61%	1.20%
Equity	45%	7.84%	3.53%	3.53%
Total			5.14%	4.73%

Formulas for the weighted average cost of capital (WACC) and after-tax weighted average cost of capital (ATWACC) are

$$WACC = \%\,Equity * \%\,Return\ on\ Equity + \%\,Debt * \%\,Cost\ of\ Debt \qquad \text{Equation 1}$$

$$ATWACC = \%\,Equity * \%\,Return\ on\ Equity + \%\,Debt * \%\,Cost\ of\ Debt * (1 - Effective\ Tax\ Rate) \qquad \text{Equation 2}$$

[1] Based on an internal market study by NETL based on Edison Electric Institute Rate Case summary, Q4 2017. [10]

The justification for the cost of equity is shown in Exhibit 3-3, which shows the results of NETL's Capital Asset Pricing Model (CAPM) analysis and total ROEs based on stock market prices of companies that own 25 percent of all generation. These companies also represent 36 percent of companies that are publicly owned.

Exhibit 3-3. Returns on equity using various methods

	1990-2018 Annual Data Results							2014 to 2017
	Annual CAPM		Annual Stock Price-Based ROE	2018 Yield	Yield + Price ROE	Yield + Levered Total ROE	Yield + Unlevered Total ROE	Net Income Total ROE
	Levered ROE	Unlevered ROE						
Average	6.9%	5.8%	5.9%	3.3%	9.2%	10.2%	9.1%	10.3%
Capacity Weighted	6.6%	5.7%	6.6%	3.2%	9.8%	9.8%	9.0%	8.5%
Market Weighted	6.2%	5.7%	6.5%	3.4%	9.9%	9.7%	9.1%	9.4%

The levered and unlevered ROEs in Exhibit 3-3 are from NETL's CAPM[2] study for the power companies using annual stock prices from 1990-2018. The CAPM study also includes using the long-term T-Bill rate as the risk-free rate, and the S&P 500 index was used as the market index for calculating the market risk premium. The levered ROE includes the effect of the company debt level, whereas the unlevered ROE removes debt from the return resulting in a lower return. This indicates that having debt at the levels of the companies sampled, averaging 55 percent, has a small influence on the total return.

Note in Exhibit 3-3 that the weighted "Annual CAPM Levered ROE" is very close to the weighted "Annual Stock Price-Based ROE," which somewhat validates the CAPM match to market results.

A "Net Income Total ROE" calculation was also completed using the 2014-2017 income statements for the companies (far right column), calculating a return using funds available to equity. Adding the recent annual yield for dividends to shareholders to the "Annual Stock Price-Based ROE" gives a total return on equity.

Based on these results, the levered ROE would be appropriate to use when added to the annual yield because they both include the companies with debt. The capacity and market weighted returns of 9.8 percent and 9.7 percent, respectively, along with the straight average "Yield + Levered Total ROE" at 10.2 percent, support using 10 percent as a reasonable ROE for a large company building a coal or natural gas plant.

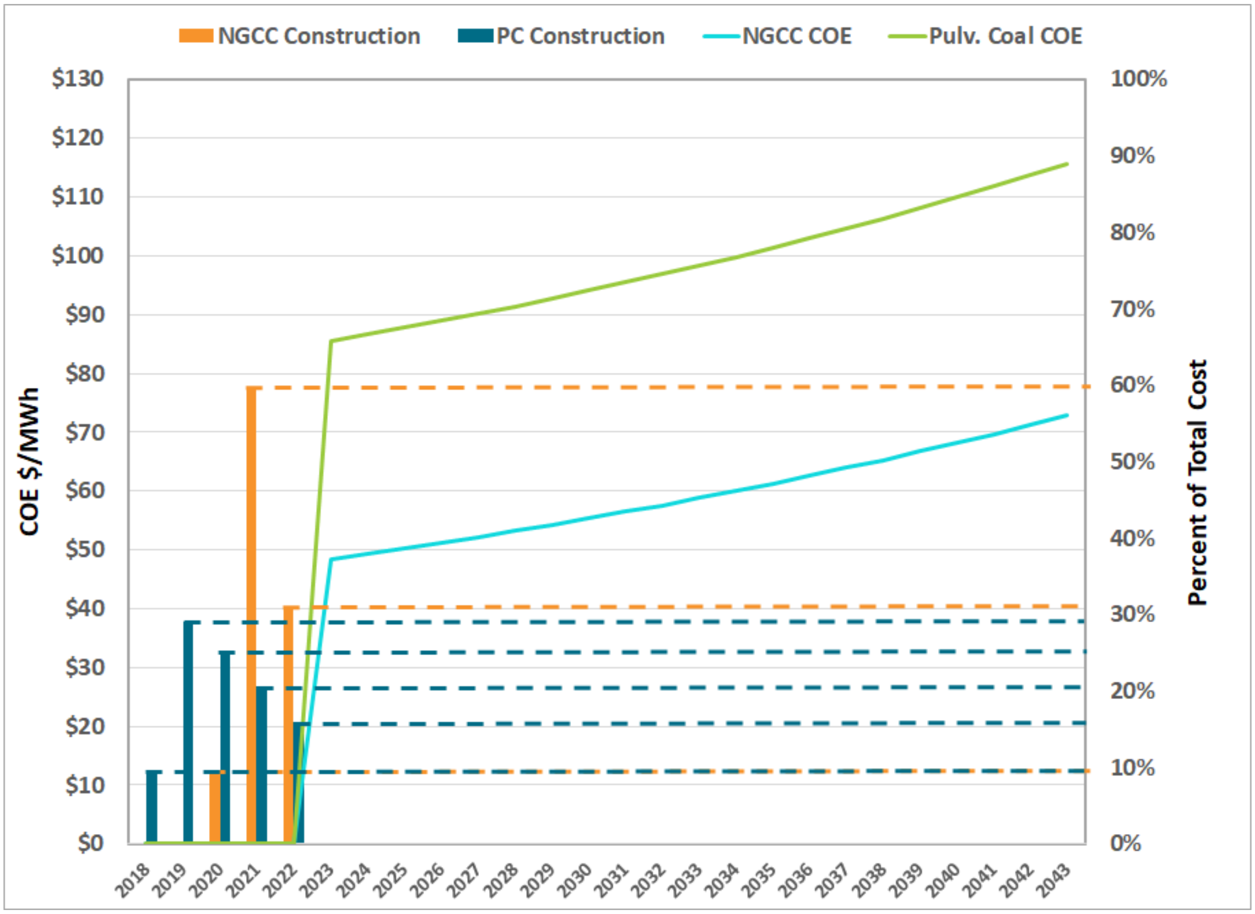
3.3 Calculating COE

The first-year COE is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation. The COE can be escalated to show it as an increasing

[2] Capital asset pricing model. ROE = risk-free rate + company beta x the market risk premium (market return minus risk-free rate). See Investopedia website for discussion on CAPM. Data obtained from yahoo finance statistics.

amount as shown in Exhibit 3-4 for PC and NGCC power plants. The COE increases because the O&M costs and fuel costs increase each year at an assumed constant escalation rate, while financed capital costs stay constant.

Exhibit 3-4. Capital expenditure periods and COE for generic coal and NGCC plants



As shown in the left side of Exhibit 3-4, the capital expenditure period is assumed to start in 2018 for the 5-year capital expenditure needed for coal plant construction, and in 2020 for the 3-year capital expenditure period needed for a NGCC. All capital costs included in this analysis, including project development and construction costs, are assumed to be incurred during the capital expenditure period. This analysis assumes that the plants begin operating in 2023 to represent a typical analysis made for a year when generation capacity is needed.

In addition to the capital expenditure period, the economic analysis considers thirty years of operation for both coal and natural gas plants.

3.4 Estimating COE and LCOE Using Formulas

The following simplified equation can be used to estimate COE as a function of TASC, fixed O&M, variable O&M, fuel costs, capacity factor, and net output. The equation requires the application of fixed charge rates (FCR) listed in Exhibit 3-5, which is based on the capital recovery factors (CRF) listed in Exhibit 3-6. These FCRs and CRFs are valid only for scenarios that adhere to the global economic assumptions listed in Exhibit 3-1 and utilize the stated finance structure listed in Exhibit 3-2 and the stated capital expenditure period. The formulas for calculating FCR and CRF values based on other assumptions are shown below in Equation 9 through and Equation 11. The formulas for calculating the FCR values include an adjustment to the CRF value to account for depreciation.

Exhibit 3-5. Fixed charge rate for COE equation

Finance Structure	IOU - 30 Years	
Capital Recovery Periods	Three Years	Five Years
FCR Nominal	0.0886	0.0886
FCR Real	0.0707	0.0707

Exhibit 3-6. Capital recovery factors

Finance Structure	IOU - 30 Years	
Capital Recovery Periods	Three Years	Five Years
CRF Nominal	0.0769	0.0769
CRF Real	0.0630	0.0630

3.4.1 Calculating the COE

All factors in the COE equation are expressed in dollars for the on-line year, which is 2023 for the current NETL Baseline Study. [2] For LCOE comparisons, the base year is the year that a comparison of technologies begins, and the year in which dollars are based. For a comparison of coal and NGCCs, all costs would begin escalation from 2018. Since the real escalation rate is assumed to be 0 percent, all real dollar amounts stay the same as in the base year, 2018. Using Equation 4 below for COE, note that the TASC is for the on-line year, and O&M and fuel costs would typically be expressed in on-line year costs to be consistent.

$$COE = \frac{\begin{matrix}first\ year \\ capital\ charge\end{matrix} + \begin{matrix}first\ year \\ fixed\ operating \\ costs\end{matrix} + \begin{matrix}first\ year \\ variable\ operating \\ costs\end{matrix}}{\begin{matrix}annual\ net\ megawatt\ hours \\ of\ power\ generated\end{matrix}} \qquad \text{Equation 3}$$

$$COE = \frac{(FCR)(TASC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)} \qquad \text{Equation 4}$$

where:

COE = revenue required to be received by the generator (\$/MWh, equivalent to mills/kWh) during the power plant's first year of operation in order to satisfy the finance structure assumptions

FCR = fixed charge rate taken from Exhibit 3-5 and based on CRF values from Exhibit 3-6 (discussed in Section 3.5 below) that matches the finance structure and capital expenditure period. The interest rate used in the formula must by necessity be the ATWACC

TASC = total as spent capital (see TOC discussion below), expressed in on-line year cost

OC_{FIX} = the sum of all first-year-of-operation fixed annual operating costs

OC_{VAR} = the sum of all first-year-of-operation variable annual operating costs at 100 percent capacity factor, including fuel and other feedstock costs and (offset by) any byproduct revenues

CF = plant capacity factor, assumed to be constant (or levelized) over the operational period; expressed as a fraction of the total electricity that would be generated if the plant operated at full load without interruption

MWH = annual net megawatt-hours of electricity generated at 100 percent capacity factor

Total Overnight Capital - The TOC may include any "overnight" capital expense incurred during the capital expenditure period, except for escalation and interest during construction. (When using the simplified COE equation, both escalation during construction and interest during construction are excluded from nominal costs.) Both depreciable and non-depreciable capital should be included in the TOC, even though the CRF was computed without a depreciation factor. For typical tax rates and depreciation schedules, this simplification introduces a negligible amount of error into the capital portion of the COE. If this simplification is not acceptable, a full discounted cash flow analysis tool (such as the NETL Power Systems Financial Model for Grid Technologies [PSFM-GT] [8]) should be used to calculate the COE instead of the simplified COE equation.

The CRF values for different capital expenditure periods are the same because both assume the operational period is equal to the term for debt and equity combined in the ATWACC used. A cash flow approach could use a 20- or 30-year debt term. A coal plant would be more likely to have a 30-year term; a combined-cycle and a combustion turbine would be more likely to have 20-year debt terms, but market conditions and owner financial conditions would influence the terms. The Federal Reserve of St. Louis reports seasoned long-term bond rates that are an average of all bonds with 20- or 30-year terms, indicating that bonds are still being issued with 30-year terms to reduce the annual revenue requirements (or LCOE). The difference between 20- and 30-year bonds is less than 0.25 points in the last ten years.

3.4.2 Estimating TASC from TOC

For scenarios that adhere to the global economic assumptions listed in Exhibit 3-1 and utilize the finance structure listed in Exhibit 3-2, the multipliers shown in Exhibit 3-7 can be used to translate TOC to TASC to account for the impact of both escalation and cost of capital during construction. The nominal TOC is expressed in base-year dollars and the corresponding nominal TASC is expressed in mixed-year, current or real dollars over the entire capital expenditure period. Exhibit 3-8 and Exhibit 3-9 illustrate the calculations for nominal TASC, and Exhibit 3-11 and Exhibit 3-11 illustrate real dollar calculations. Note that the real dollar TASC only includes the pre-tax WACC with no inflation. The nominal TASC includes a pre-tax WACC, also. The pre-tax WACC is used in calculating the TASC because no revenue is involved in the construction phase. The CRF includes an ATWACC appropriately to address the actual cost of repaying the interest on debt accrued during construction and included in the TASC factor. The formulas for calculating the TASC/TOC factors shown in Equation 5, Equation 6, and Equation 7.

Exhibit 3-7. TASC/TOC factors, nominal and real

Finance Structure	BBB+ [3] or higher Company	
Capital Expenditure Period	**Three Years**	**Five Years**
$TASC/TOC_{nominal}$	1.242	1.289
$TASC/TOC_{real}$	1.093	1.154

Exhibit 3-8. Three-year TASC, nominal detail calculations

3-Year Capital Expenditure					
Funds received Jan. 1 rolled into TASC Recovered over 30 years					
Cost Year	**Escalated Cost**	**Cost of Funding**	**WACC**	**Escalation**	**Capital Expenditure**
2018	-	-	-	0%	0%
2019	-	-	-	3%	0%
2020	0.10609	0.00769	0.0725	3%	10%
2021	0.65564	0.05523	0.0725	3%	60%
2022	0.33765	0.07970	0.0725	3%	30%
2023	1.09938	0.14262			
TASC/TOC	**1.242**				

Exhibit 3-9. Five-year TASC, nominal detail calculations

5-Year Capital Expenditure					
Funds received Jan. 1 rolled into TASC Recovered over 30 years					
Cost Year	**Escalated Cost**	**Cost of Funding**	**WACC**	**Escalation**	**Capital Expenditure**
2018	0.10000	0.00725	0.0725	3%	10%
2019	0.30900	0.02965	0.0725	3%	30%
2020	0.26523	0.04888	0.0725	3%	25%
2021	0.21855	0.06473	0.0725	3%	20%
2022	0.16883	0.07697	0.0725	3%	15%
2023	1.06160	0.22748			
TASC/TOC	**1.289**				

[3] Standard & Poor's rating levels.

Exhibit 3-10. Three-year TASC, real detail calculations

3-Year Capital Expenditure					
Funds received Jan. 1 rolled into TASC Recovered over 30 years					
Cost Year	Escalated Cost	Cost of Funding	WACC	Escalation	Capital Expenditure
2018	-	-	-	0%	0%
2019	-	-	-	0%	0%
2020	0.10	0.00514	0.0514	0%	10%
2021	0.60	0.03599	0.0514	0%	60%
2022	0.30	0.05141	0.0514	0%	30%
2023	1.0	0.09254			
TASC/TOC	**1.093**				

Exhibit 3-11. Five-year TASC, real detail calculations

5-Year Capital Expenditure					
Funds received Jan. 1 rolled into TASC Recovered over 30 years					
Cost Year	Escalated Cost	Cost of Funding	WACC	Escalation	Capital Expenditure
2018	0.10	0.00514	0.0514	0%	10%
2019	0.30	0.02056	0.0514	0%	30%
2020	0.25	0.03342	0.0514	0%	25%
2021	0.20	0.04370	0.0514	0%	20%
2022	0.15	0.05141	0.0514	0%	15%
2023	1.00	0.15423			
TASC/TOC	**1.154**				

$$\frac{TASC}{TOC} = Escalaton\ + Costof\ Funding \qquad \text{Equation 5}$$

where:

$$Escalation\ = \sum_{n=1}^{y} \left[(\ 1 + i)^{(n-1)} * \%Capital_n \right] \qquad \text{Equation 6}$$

$$Cost\ of\ Funding = \sum_{n=1}^{y} WACC * (y - n + 1) * (\ 1 + i)^{(n-1)} * \%Capital_n \qquad \text{Equation 7}$$

where:

n = the year of capital expenditure

y = total number of years of capital expenditure

i = assumed escalation rate for capital during the expenditure period (nominal or real)

$\%Capital_n$ = percent of TOC expenditure for year n

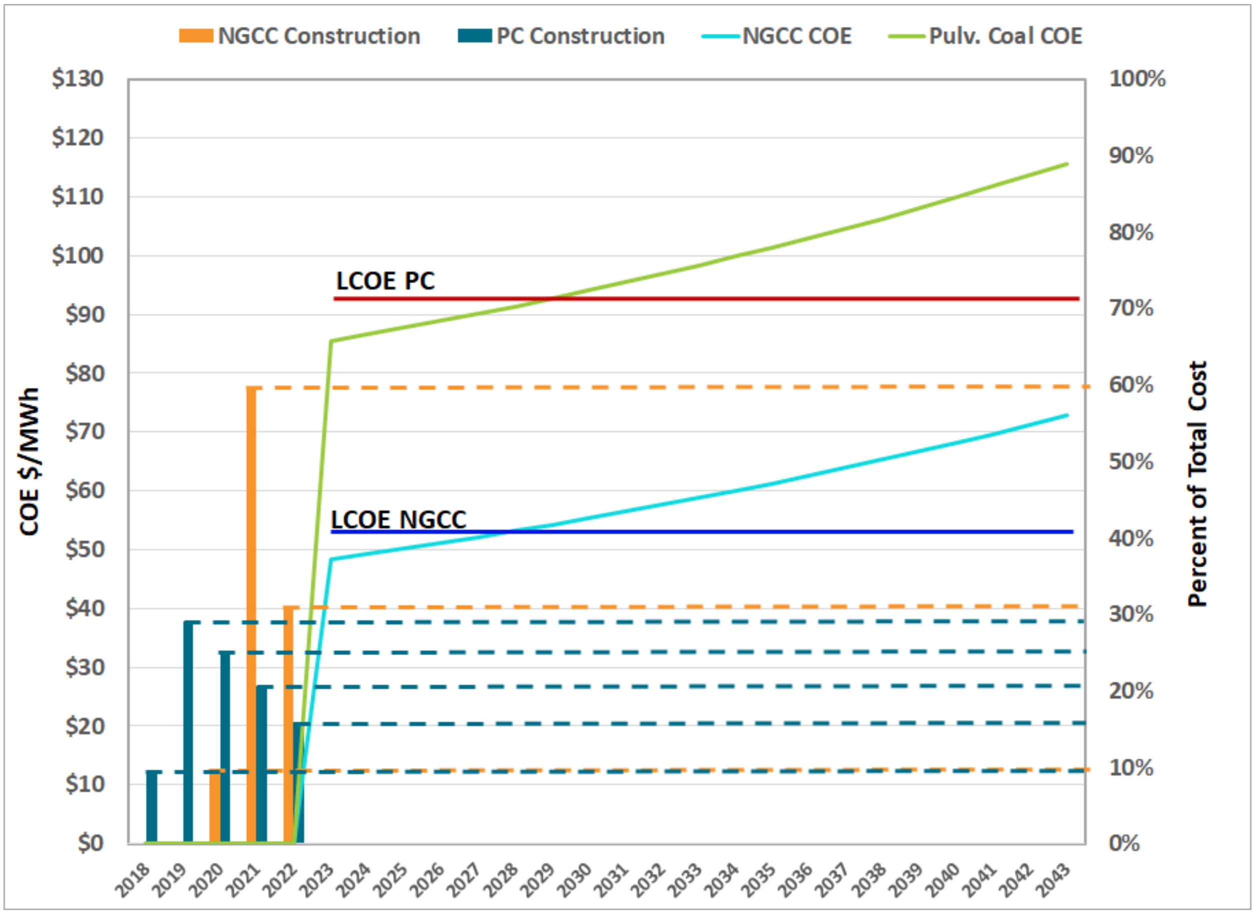
WACC = weighted average cost of capital (nominal or real) from Equation 1

Given these factors, the LCOEs can be calculated without the use of a cash flow model, which would result in a more complete estimation, although the formulaic calculations presented here provide reasonable estimates for research and development comparisons. When technologies go to markets, a detailed cash flow estimate is needed for owners to determine their resource choices, and models like the PSFM-GT developed by NETL can be used to compare resources over different time horizons in cash flow analyses. [8] A summary of the PSFM-GT is provided in Appendix A.

3.5 Estimating LCOE

To illustrate how an LCOE is related to a COE, solutions are shown in Exhibit 3-12 for a generic PC power plant and a generic NGCC power plant. The LCOE is the amount of revenue required per net megawatt-hour during the power plant's operational life to meet all capital and operational costs. The LCOE is primarily for the comparison of technologies on a $/MWh basis needed in the power market, or price, to support the construction and operation of power plants under assumed operational conditions and costs. Since there are many factors that can vary for different generation technologies, such as fuel prices, O&M, and capital construction costs, naturally it is convenient to combine all of these costs into a levelized cost rather than try to judge which technology is lower cost by comparing the cost components separately.

Exhibit 3-12. LCOE compared to COE escalated with construction costs



The LCOE has always been a "first-cut" type of screening tool, and can be calculated by using either real or nominal dollar formulas as described below:

1) Calculate the levelized capital cost (LCC) using the fixed charge rate and capital recovery factor (CRF) formulas as follows for a nominal (q) approach: [9, 10]

$$LCC_q = TASC_q * FCR_q \quad \text{Equation 8}$$

where:

$$FCR_q = \frac{CRF_q}{(1-ETR)} - \frac{ETR * D_q}{(1-ETR)} \quad \text{Equation 9}$$

and

$$CRF_q = \frac{ATWACC_q * \left(1+ATWACC_q\right)^y}{\left(1+ATWACC_q\right)^y - 1} \quad \text{Equation 10}$$

and:

$$D_q = CRF_q * \sum_{n=1}^{z} \frac{d_n}{\left(1+ATWACC_q\right)^n} \quad \text{Equation 11}$$

where:

TASC = total as spent costs, as defined in Section 2.1

FCR = Fixed charge rate

CRF = Capital recovery factor

ETR = effective tax rate

$ATWACC_q$, = nominal after tax weighted average cost of capital (from Equation 2)

D_q = Present value of tax depreciation expense

d_n = the tax depreciation fraction in year n [11]

Note: The values used to generate the tables in this QGESS are based on 2016 IRS Publication 946 Table A-14. 150% Declining Balance Method Half-Year Convention

z = number of years of depreciation, (21 for 20-year, 150% declining balance)

Real values can be substituted into the components with the subscript q to convert formulas for real results.

2) Calculate levelized annual O&M expenses (AOM)[4] per MWh using the following formula:

$$LOM = AOM * \frac{ATWACC * (1+ATWACC)^y}{(1+ATWACC)^y - 1} * \frac{1 - \left[\frac{(1+i)}{(1+ATWACC)}\right]^y}{ATWACC - i} \quad \text{Equation 12}$$

where:

y = number of operating years, (typically 30 years for coal and natural gas plants)

i = assumed annual escalation rate for O&M (nominal or real)

ATWACC, = after tax weighted average cost of capital (nominal or real) from Equation 2

[4] Fixed O&M is also put on a $/MWh basis and added to the variable O&M, the same as (OC_{Fix} +OC_{Var})/MWh.

This formula can also be expressed as the CRF times the net present value of the average compound inflation factors using the ATWACC as the discount rate. See fuel prices below, which can use a forecast of annual fuel prices to calculate a levelized fuel price as opposed to using an average annual escalation rate as above. Thus, the right side of the formula has interchangeable escalation rate and fuel price levelization approaches.

The real dollar approach simply applies the real levelization factor times the base year O&M costs per MWh. For the assumptions listed in Exhibit 3-1 where real escalation is specified as zero, the levelized value equals the annual value, LOM_{real} = AOM.

The nominal levelization factor for O&M using a 3 percent annual escalation over 30 years is 1.384, $LOM_{nominal}$ = 1.384 * AOM.

3) Calculate levelized annual fuel (LFP) expenses per MWh using the price forecast for fuel costs as shown below [6]. The levelized real value to use for several coal types and natural gas are in NETL's Quality Guidelines for Energy System Studies (QGESS) update for fuels [6], and these levelized costs are for a 2023-2052 (30 years) operating period, calculated as follows:

$$LFP = PV_{fuel\ price} * \frac{ATWACC * (1 + ATWACC)^y}{(1 + ATWACC)^y - 1} \qquad \text{Equation 13}$$

where:

$$PV_{fuel\ price} = \sum_{n=1}^{y} \frac{P_n}{(1 + ATWACC)^n} \qquad \text{Equation 14}$$

where:

n = the year of operation

y = number of operating years (typically 30 years for coal and natural gas plants)

P_n = price of fuel in year n (nominal or real)

ATWACC, = weighted average cost of capital (nominal or real) from Equation 2

Applying these to the base year cost component on a MWh basis will provide the $/MWh cost from the following LCOE formula, or, 2018 dollar levelized prices from the QGESS fuel update can be used. The real or nominal LCOE can be obtained from the following formula:

$$LCOE = LCC + LOM + LFP \qquad \text{Equation 15}$$

4 References

[1] Association for the Advancement of Cost Engineering (AACE) International, "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries; AACE International Recommended Practice No. 18R-97," AACE International, Morgantown, WV, 2005, Rev. March 1, 2016.

[2] National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 4," Department of Energy, Pittsburgh, PA, 2019 (pending).

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[4] Electric Power Research Institute (EPRI), "Technical Assessment Guide (TAG®) – Power Generation and Storage Technology Options, EPRI Product ID No. 1017465," EPRI, Palo Alto, CA, 2009.

[5] Whitman, Requardt & Associates, LLP, "The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1 2018," Whitman, Requardt and Associates, Baltimore, MD, 2018.

[6] National Energy Technology Laboratory (NETL), "Quality Guidelines for Energy Systems Studies: Fuel Prices for Selected Feedstocks," Department of Energy, Pittsburgh, Pa, 2019 (pending).

[7] U.S. Bureau of Economic Analysis, "Real Gross Domestic Product [GDPC1]," FRED, Federal Reserve Bank of St Lewis, [Online]. Available: https://fred.stlouisfed.org/series/GDPC1/. [Accessed 6 March 2018].

[8] National Energy Technology Laboratory, "Power Systems Financial Model-Grid Technologies,Version 1.0," Department of Energy, Pittsburgh, PA, 2019 (pending).

[9] Grant, Ireson, and Leavenworth, Principles of Engineering Economy, Seventh Edition, Hoboken, NJ: John Wiley & Sons, 1982.

[10] W. R. Meier, "A Standard Method for Economic Analysis of Inertial Confinement Fusion Power Plants," The Seventh Topical Meeting on the Technology of Fusion Energy, Reno, Nevada, 1986.

[11] Internal Revenue Service, "Publication 946 How to Depreciate Property," Department of the Treasury, Washington, D.C., 2016.

[12] Edison Electric Institute (EEI), "EEI Q4 2017 Financial Update," Edison Electric Institute, Washington, D.C., February 2018.

Appendix A: The Power System Financial Model for Grid Technologies

The Power System Financial Model for Grid Technologies (PSFM-GT) was designed to model cash flows for up to 15 technologies with full income and cash flow tables at once. [8] It includes the capability of calculating levelized cost of electricity (LCOE) in several different ways: nominal, real dollars, formulaic, and goal-seeking. These are included to address different preferences for approach and one's desire to cross-check methods. There are potential short-comings of each approach depending on the technology cash flow structure and variability due to subsidies and applicable tax laws, depreciation, etc.

For instance, the formula method requires that each item to be included in the LCOE should have a price over the same number of years. This makes it difficult for a 20-year debt term to be included when a technology has a different length life. Depreciation isn't typically included in a formula approach.

The PSFM-GT can be useful in comparing several technology types including those that may be on the other side of the consumer meter such as rooftop solar, batteries, and electric vehicles. Renewable generation can also be compared over 40- to 60-year periods if desired, enabling repeated installations to be compared to long-lived generation such as nuclear or coal. Market pricing inputs are also available to input revenue sources flowing back to a technology so an internal rate of return (IRR) can be calculated if one wanted to investigate market conditions or opportunities for a technology. A link to the PSFM-GT is planned for publication on the NETL website on the Energy Analysis page in 2019.

Appendix B: Changes in Methodology Used in the Bituminous Baseline Reports from Revision 3 to Revision 4

For revision 3 of the Bituminous Baseline report, the base-year cost of electricity (COE) values were calculated as those that generated an internal rate of return (IRR) equal to the specified return on equity (ROE) based on typical economic assumptions for power plant projects. For revision 4 of the Bituminous Baseline report, the base-year real levelized cost of electricity (LCOE) values are calculated using the after-tax weighted average cost of capital (ATWACC) based on typical economic assumptions for power plant projects. Because real escalation on the COE components is assumed to be zero (i.e., inflation equals nominal escalation), the real LCOE values equal the base-year COE values. While many assumptions remained the same between revision 3 and 4, those that changed are listed in Exhibit B-1.

Exhibit B-1. Changes in global economic assumptions

Parameter	Revision 3 Value	Revision 4 Value
Basis of Method	Project Financing, IRR = ROE = 12%	Discount Rate based on ATWACC = 4.72% real
Income Tax Rates	34% Federal, 6% State (Effective 38%)	21% Federal, 6% State (Effective 25.74%)
CONTRACTING AND FINANCING TERMS		
Debt/Equity Split	Commercial IOU = 50/50 TASC High Risk IOU = 45/55 TASC	Commercial IOU = 55/45 TOC
Debt Term	15 year	30 years (Equals operating period)
Debt Interest Rate	Commercial IOU = 4.5% nominal High Risk IOU = 5.5%, nominal	Commercial IOU = 2.94% real
Return on Equity	12%, nominal	7.84% real
TREATMENT OF CAPITAL COSTS		
Capital Cost Escalation During Capital Expenditure Period	3.6% nominal	0% real
Interest During Construction	100% Debt financed with annual accrual included in TASC	Annual charge included in TASC without accrual
ROE during construction	Not included	Annual charge included in TASC without accrual
ESCALATION OF OPERATING COSTS AND REVENUES		
Escalation of COE (revenue), O&M Costs	3% nominal	0% real
Fuel Costs	3% nominal	Levelized real value from QGESS on Fuel Price

The changes to the treatment of capital costs listed in Exhibit B-1 resulted in new total as-spent capital (TASC)/total overnight cost (TOC) factors listed in Exhibit B-2. The difference is predominantly due to the inclusion of the ROE during the construction period and the removal of the capitalization of all interest during construction as debt, including the additional accrual of interest on that interest.

Exhibit B-2. Changes in TASC/TOC factors

Parameter	Revision 3 TASC/TOC	Revision 4 TASC/TOC	% Increase
3-year construction period (natural gas cases)	Commercial IOU = 1.075 High Risk IOU = 1.078	Commercial IOU = 1.093	1.3%-1.6%
5-year construction period (coal cases)	Commercial IOU = 1.134 High Risk IOU = 1.140	Commercial IOU = 1.154	1.2%-1.8%

The changes in the financial assumptions listed in Exhibit B-1 as well as switching the basis of the methodology from a project-focused calculation where the IRR was assumed to match the 12 percent ROE to a corporate-focused calculation using the ATWACC as the discount rate resulted in new calculations for the capital component of the COE. The revision 3 values were based on multiplying the TOC by capital charge factors (CCF) which were calculated in a detailed cash flow model for specific assumptions. The revision 4 values are based on multiplying the TASC by fixed charge rate (FCR) which are calculated using the formula method described in this document. The impact of the change is estimated by comparing the CCF values with FCR*TASC/TOC values listed in Exhibit B-3. The difference in values is predominantly due to the simplification of the calculations, which are based on real escalation equaling zero, the real ROE of 7.3 percent, and the debt terms equaling the operation life.

Exhibit B-3. Changes in capital component factors

Parameter	Revision 3 CCF	Revision 4 FCR	Revision 4 FCR*TASC/TOC	% decrease
3-year construction period (natural gas cases)	Commercial IOU = 0.105 High Risk IOU = 0.111	Commercial IOU = 0.0707	Commercial IOU = 0.0773	26%-30%
5-year construction period (coal cases)	Commercial IOU = 0.116 High Risk IOU = 0.124	Commercial IOU = 0.0707	Commercial IOU = 0.0817	29%-34%

Appendix C: Revision Control

Exhibit C-1. Revision table

Revision Number	Revision Date	Description of Change
0	April 2011	Initial publication
1	February 2014	Front matter added and document reformatted
2	May 2015	Updated to reflect minor changes and 2011 dollar year
3	September 2019	Simplified calculations to specify values and formulas for calculating real LCOE based on FCR instead of COE based on CCFs (see Appendix B)