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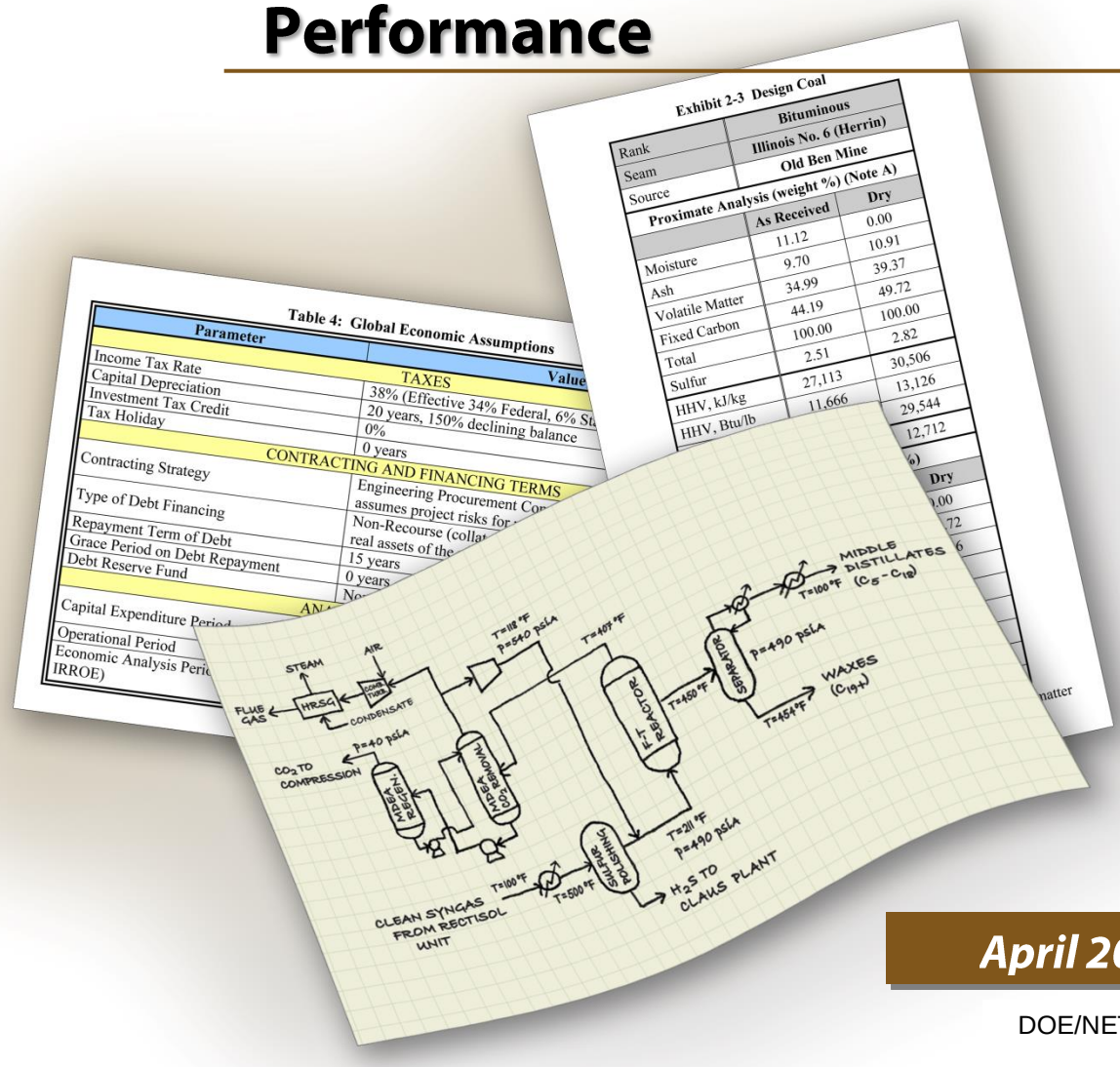
Cost Estimation Methodology for NETL Assessments of Power Plant Performance



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Cost Estimation Methodology for NETL Assessments of Power Plant Performance

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Final Report

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Acronyms and Abbreviations

AACE	Association for the Advancement of Cost Engineering
BEC	Bare erected cost
CCF	Capital charge factors
CCS	Carbon capture and sequestration
COE	Cost of electricity
CO_2	Carbon dioxide
DCF	Discounted cash flow
DOE	Department of Energy
EPC	Engineering, procurement, and construction
EPCC	Engineering, procurement, and construction cost
EPCM	Engineering, procurement, and construction management
EPRI	Electric Power Research Institute
IOU	Investor-owned utility
IGCC	Integrated gasification combined cycle
IPP	Independent power producer
LCOE	Levelized cost of electricity
LF	Levelization factor
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
O&M	Operation and maintenance
PC	Pulverized coal
PSFM	Power systems financial model
TASC	Total as-spent capital
TCM	Total cost management
TOC	Total overnight cost
TPC	Total plant cost
$/kW	Dollars per kilowatt
$/MWh	Dollars per megawatt

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1 Introduction

This paper summarizes the costing methodology employed by the National Energy Technology Laboratory (NETL) in its costing models and baseline reports. Further, it defines the specific levels of capital cost as well as outlines the costing metrics by which NETL evaluates various power producing 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. Though these guidelines are tailored for power producing plants, they can also 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, this methodology defines capital cost at five levels: BEC, EPCC, TPC, TOC, and TASC. BEC, EPCC, TPC and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure. 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.

The Bare Erected Cost (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. The cost of EPC services and contingencies are not included in BEC. BEC is an overnight cost expressed in base-year dollars.

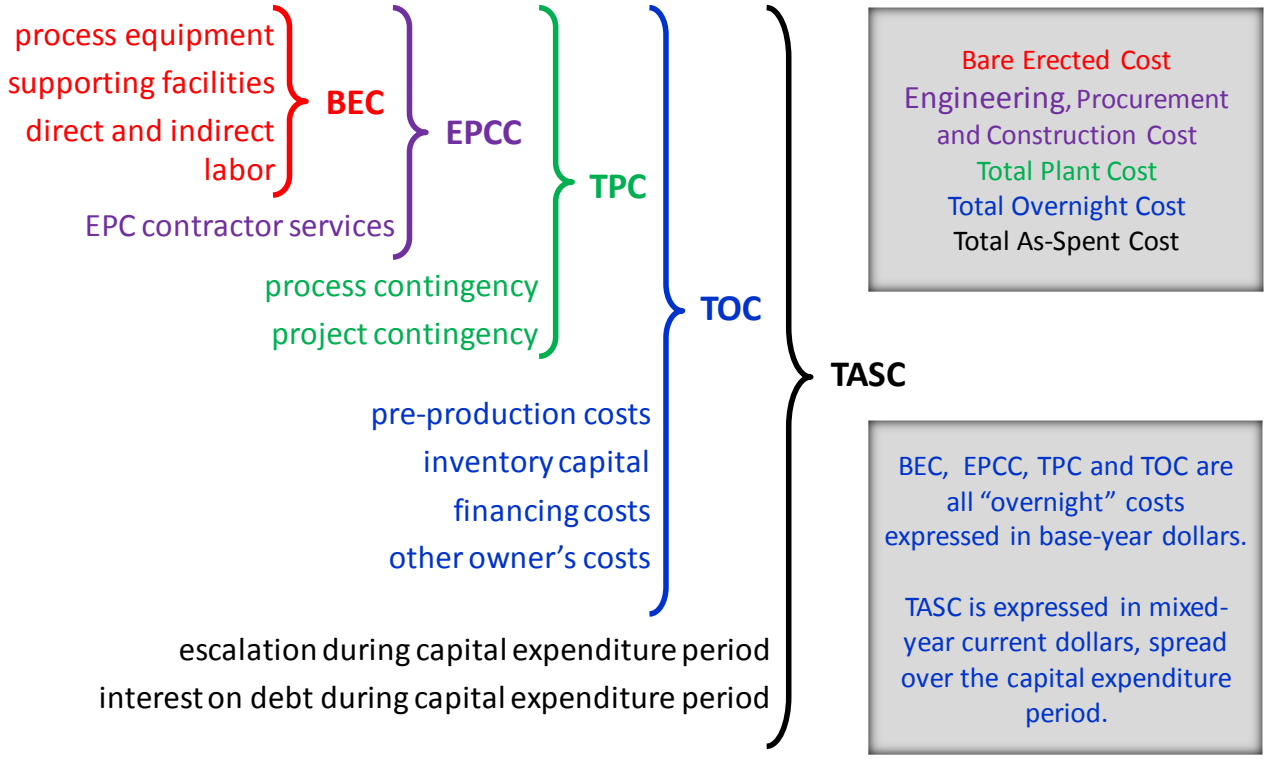
The Engineering, Procurement, and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the engineering, procurement, and construction (EPC) contractor. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs. EPCC is an overnight cost expressed in base-year dollars.

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies. TPC is an overnight cost expressed in base-year dollars.

The Total Overnight Capital (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 interest during construction. TOC is an overnight cost expressed in base-year dollars.

The Total As-Spent Capital (TASC) is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Exhibit 2-1 Capital cost levels and their elements



Source: NETL

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 for the process industries. [1]

Most techno-economic studies completed by NETL feature cost estimates intended for the purpose of a "Feasibility Study" (AACE Class 4). Exhibit 2-2 describes the characteristics of an AACE Class 4 cost estimate.

Cost estimates in most NETL studies have an expected accuracy range of -15%/+30%.

Exhibit 2-2 Features of an AACE Class 4 cost estimate

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	-15% to -30% on the low side, and +20% to +50% on the high side

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).

EPCM contractor services are estimated at 8 to 10 percent of BEC. 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, resident engineer, 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 unknown costs that are omitted or unforeseen 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
- the performance of the plant after startup (e.g., availability, efficiency).

<u>Process Contingency</u>

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.

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

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

Process contingency is typically not applied to costs that are set equal to a research goal or programmatic target since these values presume to reflect the total cost.

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. [2]

2.5 Estimation of Owner's Costs

Exhibit 2-4 explains the estimation method for owner's costs. With some exceptions, the estimation 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 International Recommended Practice No. 16R-90. [2] 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. [3] The EPRI and AACE guidelines are very similar.

Exhibit 2-4 Estimation method 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 [2] and EPRI TAG® [3] 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 WGS, COS, and SCR catalysts and activated carbon. AACE 16R-90 [2] does not include an inventory cost for fuel, but EPRI TAG® [3] does.

Owner's Cost	Estimate Basis
Land	• $3,000/acre (300 acres for IGCC and PC, 100 acres for NGCC)
Financing Cost	• 2.7% of TPC This financing cost (not included by AACE 16R-90 [2]) 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 2008 private communication with a capital services firm.
Other Owner's Costs	• 15% of TPC This additional lumped cost is not included by AACE 16R-90 [2] or EPRI TAG®. [3] The "rule of thumb" estimate (15% of TPC) is based on a 2009 private communication with Worley-Parsons. 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 Engineering Procurement Construction Management 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 bare erected cost, 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.

3 Cost Estimate Scope

All estimates represent a complete power plant facility on a generic site. 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, storage, and monitoring (T&S). T&S costs are embedded in the reported COE but are not represented in the plant capital or 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 & substation

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

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 condenser
- Automated coal reclaim
- Zero Liquid Discharge equipment
- Selective catalytic reduction (SCR) catalyst (Integrated gasification combined cycle [IGCC] cases only)

4 Economic Analysis

4.1 Global Economic Assumptions

Global economic assumptions are listed in Exhibit 4-1.

Exhibit 4-1 Global economic assumptions

Parameter	Value
TAXES	
Income Tax Rate	38% Effective (34% Federal, 6% State)
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	15 years
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 (used for IRROE)	33 or 35 Years (capital expenditure period plus operational period)
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Capital Expenditure Period (nominal annual rate)	3.6%[1]
Distribution of Total Overnight Capital over the Capital Expenditure Period (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% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
ESCALATION OF OPERATING REVENUES AND COSTS	
Escalation of COE (revenue), O&M Costs, Fuel Costs (nominal annual rate)	3.0%[2]

[1] A nominal average annual rate of 3.6% is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.

[2] An average annual inflation rate of 3.0% is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

4.2 Finance Structures

Finance structures were chosen based on the assumed type of developer/owner (investor-owned utility [IOU or independent power producer [IPP]) and the assumed risk profile of the plant being assessed (low-risk or high-risk). For the following example, the owner/developer was assumed to be an investor-owned utility. All IGCC cases as well as pulverized coal (PC) and natural gas combined cycle (NGCC) cases with CO_2 capture would be considered high risk. Non-capture PC and NGCC cases would be considered low risk. Exhibit 4-2 describes the low-risk IOU and high-risk IOU finance structures that were assumed for the example. Exhibit 4-3 describes the finance structure that would be used if an independent power producer developer/owner were assumed. These finance structures were recommended in a 2008 NETL report, "Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects," based on interviews with project developers/owners, financial organizations and law firms.

Exhibit 4-2 Financial structure for investor owned utility high and low risk projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
LOW RISK				
Debt	50	4.5%	2.25%	
Equity	50	12%	6%	
Total			8.25%	7.39%
HIGH RISK				
Debt	45	5.5%	2.475%	
Equity	55	12%	6.6%	
Total			9.075%	8.13%

Exhibit 4-3 Financial structure for independent power producer high and low risk projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
LOW RISK				
Debt	70	6.5%	4.55%	
Equity	30	20%	6%	
Total			10.55%	8.82%
HIGH RISK				
Debt	60	8.5%	5.1%	
Equity	40	20%	8.0%	
Total			13.1%	11.16%

4.3 DCF Analysis and Cost of Electricity

The NETL Power Systems Financial Model (PSFM) is a nominal-dollar[3] (current dollar) discounted cash flow (DCF) analysis tool. [4] As explained below, the PSFM was used to calculate COE[4] in two ways: a COE and a levelized COE (LCOE). To illustrate how the two are related, COE solutions are shown in Exhibit 4-4 for a generic PC power plant and a generic NGCC power plant, each with carbon capture and sequestration (CCS).

- The **COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the PSFM was used to determine a COE in the first year of operation that, when escalated at the assumed nominal annual general inflation rate of 3 percent[5], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The COE solutions are shown as curves in the upper portion of Exhibit 4-4 for a PC power plant and a NGCC power plant.
- The **LEVELIZED COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate of 0 percent, i.e., that it remains constant in nominal terms over the operational period of the power plant.* These guidelines report LCOE on a current-dollar basis over thirty years. "Current dollar" refers to the fact that levelization is done on a nominal, rather than a real, basis[6]. "Thirty-years" refers to the length of the operational period assumed for the economic analysis. The LCOE is calculated by multiplying the COE by a levelization factor (LF) that is a function of the IRROE and the general inflation rate that was applied to the COE. (An equation to calculate the levelization factor is provided on Page 14.) For the example PC and NGCC power plant cases, the LCOE solutions are shown as horizontal lines in the upper portion of Exhibit 4-4.

Exhibit 4-4 also illustrates the relationship between COE and the assumed developmental and operational timelines for the power plants. As shown in the lower portion of Exhibit 4-4, the capital expenditure period is assumed to start in 2007 for all cases in this example. All capital costs included in this analysis, including project development and construction costs, are assumed to be incurred during the capital expenditure period. Coal-fueled plants are assumed to have a capital expenditure period of five years and natural gas-fueled plants are assumed to have a capital expenditure period of three years. Since both types of plants begin expending capital in the base year (2007), this means

[3] Since the analysis takes into account taxes and depreciation, a nominal dollar basis is preferred to properly reflect the interplay between depreciation and inflation. A nominal dollar basis is also useful for comparing estimated costs with reported costs for actual projects, which are frequently expressed in total, as-spent, mixed, current-year dollars. For government-sponsored projects, expressing cost estimates on a nominal-dollar basis matches the appropriations process, which is done in current-year dollars.

[4] For this calculation, "cost of electricity" is somewhat of a misnomer because from the power plant's perspective it is actually the "price" received for the electricity generated for which the required IRROE is attained. However, since the price paid for generation is ultimately charged to the end user, from the customer's perspective it is part of the cost of electricity.

[5] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

[6] For this current-dollar analysis, the LCOE is uniform in current dollars over the analysis period. In contrast, a constant-dollar analysis would yield an LCOE that is uniform in constant dollars over the analysis period.

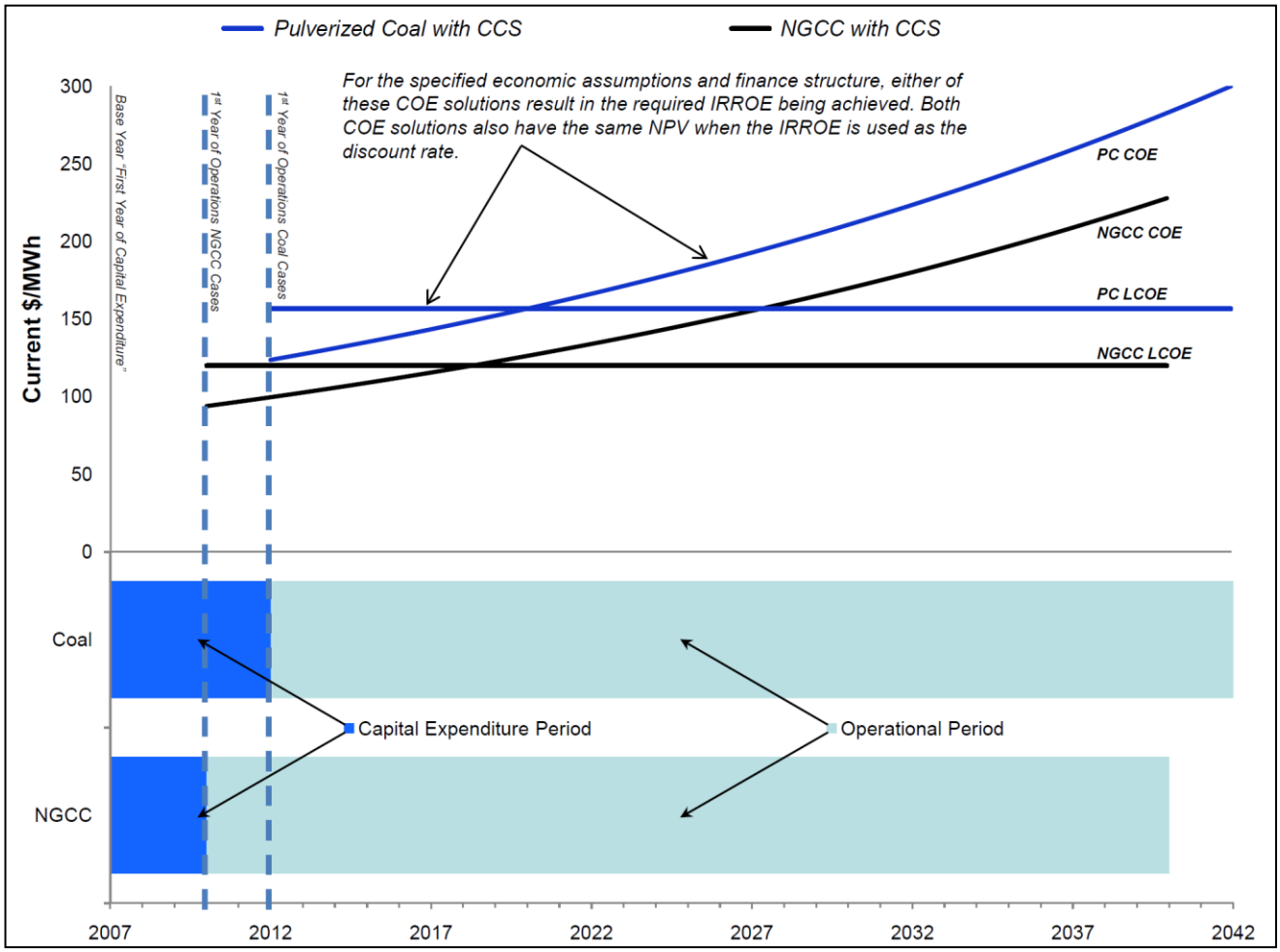
that the analysis assumes that they begin operating in different years: 2012 for coal plants and 2010 for natural gas plants for this example.

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

Since 2007 is the first year of the capital expenditure period, it is also the base year for the economic analysis. Accordingly, it is convenient to report the results of the economic analysis in base-year (2007) dollars, except for TASC, which is expressed in mixed-year, current dollars over the capital expenditure period.

Consistent with our nominal-dollar discounted cash flow methodology, the COE values shown on Exhibit 4-4 are expressed in current dollars. However, they can also be expressed in constant, base year dollars (2007) as shown in Exhibit 4-5 by adjusting them with the assumed nominal annual general inflation rate (3 percent).

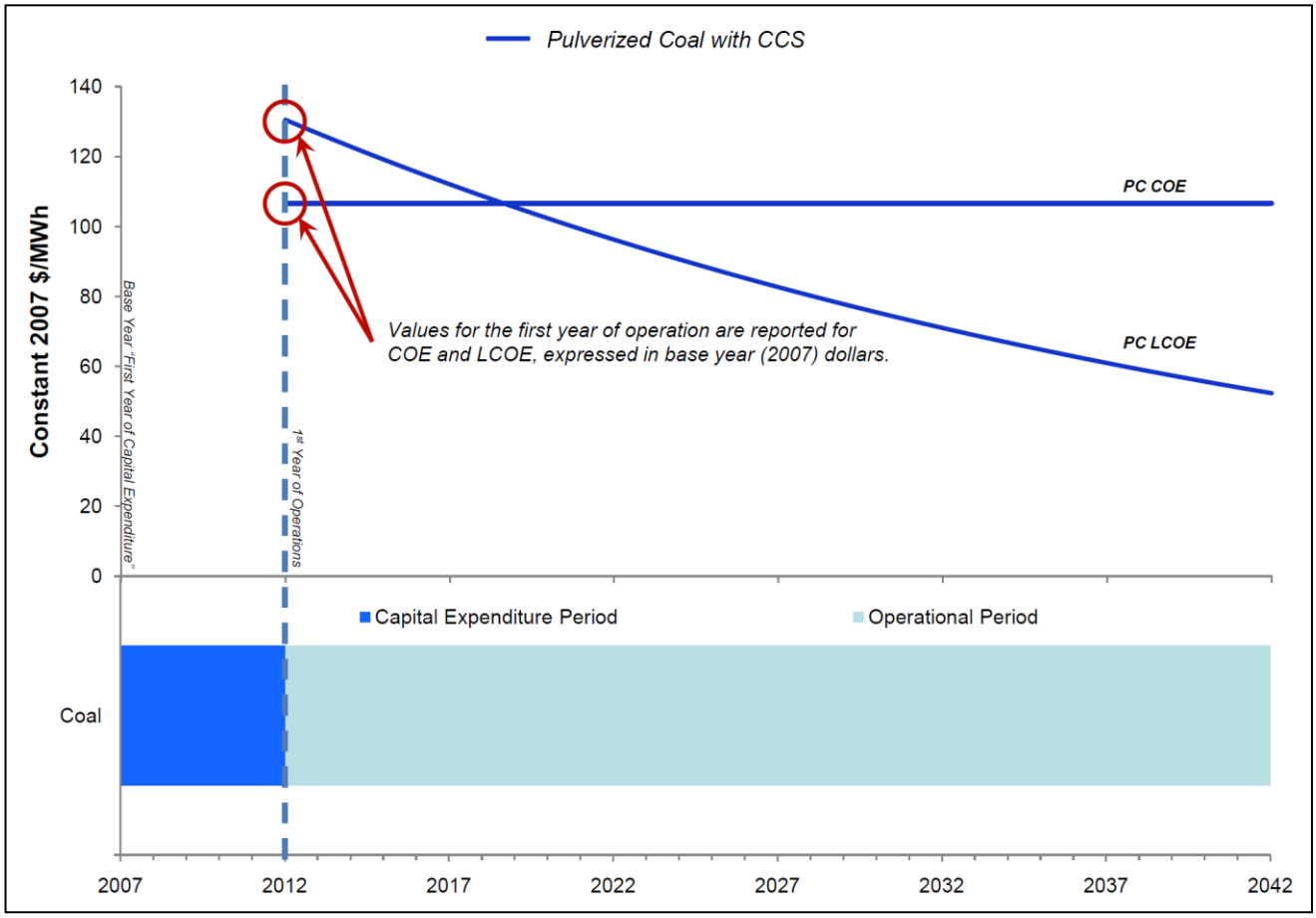
Exhibit 4-4 Illustration of COE and LCOE solutions using current-dollar DCF analysis



Source: NETL

Exhibit 4-5 illustrates the same information as in Exhibit 4-4 for a PC plant with CCS only on a constant 2007 dollar basis. With an assumed nominal COE escalation rate equal to the rate of inflation, the COE line now becomes horizontal and the LCOE decreases at a rate of 3 percent per year.

Exhibit 4-5 Depiction of current-dollar COE and LCOE solutions in constant dollars



Source: NETL

4.4 Estimating COE and LCOE with Capital Charge Factors

For scenarios that adhere to the global economic assumptions listed in Exhibit 4-1 and utilize one of the finance structures listed in Exhibit 4-2, the following simplified equation can be used to estimate COE as a function of TOC[7], fixed O&M, variable O&M (including fuel), capacity factor, and net output. The equation requires the application of one of the capital charge factors (CCF) listed in Exhibit 4-6 for an IOU finance structure and Exhibit 4-7 for an IPP. These CCFs, which were calculated using the NETL Power Systems Financial Model, are valid only for the global economic assumptions listed in Exhibit 4-1, the stated finance structure, and the stated capital expenditure period.

All factors in the COE equation are expressed in base-year dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. As shown in Exhibit 4-1, all factors

[7] Although TOC is used in the simplified COE equation, the CCF that multiplies it accounts for escalation during construction and interest during construction (along with other factors related to the recovery of capital costs).

(COE, O&M, and fuel) are assumed to escalate at a nominal annual general inflation rate of 3.0 percent. Accordingly, all first-year costs (COE and O&M) are equivalent to base-year costs when expressed in base-year (2007) dollars.

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

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE = revenue received by the generator ($/MWh, equivalent to mills/kWh) during the power plant's first year of operation (*but expressed in base-year dollars*), assuming that the COE escalates at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant

CCF = capital charge factor taken from Exhibit 4-6 that matches the applicable finance structure and capital expenditure period

TOC = total overnight capital (see note below), *expressed in base-year dollars*

OC_{FIX} = the sum of all first-year-of-operation fixed annual operating costs, *expressed in base-year dollars*

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, *expressed in base-year dollars*

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 during construction and interest during construction. (When using the simplified COE equation, both escalation during construction and interest during construction are "embedded" in the capital charge factor.) Both depreciable and non-depreciable capital should be included in the TOC, even though the CCF was computed assuming that all capital is depreciable. 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) should be used to calculate the COE instead of the simplified COE equation.

Exhibit 4-6 Capital charge factors for COE equation IOU

Finance Structure	High Risk IOU		Low Risk IOU	
Capital Expenditure Period	Three Years	Five Years	Three Years	Five Years
Capital Charge Factor (CCF)	0.111	0.124	0.105	0.116

Exhibit 4-7 Capital charge factors for COE equation IPP

Finance Structure	High Risk IPP		Low Risk IPP	
Capital Expenditure Period	Three Years	Five Years	Three Years	Five Years
Capital Charge Factor (CCF)	0.177	0.214	0.149	0.176

To calculate a Levelized COE, a levelization factor is applied to the COE that is expressed in base year dollars. Exhibit 4-4 shows LCOE's in operational year dollars. To get the LCOE that is presented in Exhibit 4-4, the LCOE must be escalated from base year dollars to the first year of operation using an annual 3 percent general inflation rate over the capital expenditure period. After the first year of operation the LCOE escalates at 0 percent over the operational period.

$$COE * LF = LCOE$$

4.5 Levelization Equation

Levelization factors were computed using the following end of the year cost formula:

$$LF = \frac{A*(1-K^{LP})}{(D-N)}$$

$$K = \frac{1+N}{1+D}$$

$$A = \frac{D*(1+D)^{LP}}{(1+D)^{LP}-1}$$

where:

LF = levelization factor
LP = levelization period, years
D = discount rate - used the Internal Rate of Return on Equity (IRROE)
N = nominal escalation rate

Note that nominal escalation was computed as:

$$N = R + I$$

where:

R = real escalation rate
I = inflation rate

Exhibit 4-8 shows the levelization factors calculated for IOU and IPP finance structures using the above equation.

Exhibit 4-8 Levelization factors

Finance Structure	IOU @ 12% IRROE	IPP @ 20% IRROE
Levelization Factor (LF)	1.268	1.169

4.6 Estimating TASC from TOC

For scenarios that adhere to the global economic assumptions listed in Exhibit 4-1 and utilize one of the finance structures listed in Exhibit 4-2, the multipliers shown in Exhibit 4-9 can be used to translate TOC to TASC to account for the impact of both escalation and interest during construction. TOC is expressed in base-year dollars and the resulting TASC is expressed in mixed-year, current-year dollars over the entire capital expenditure period.

Exhibit 4-9 TASC/TOC factors

Finance Structure	High Risk IOU		Low Risk IOU	
Capital Expenditure Period	Three Years	Five Years	Three Years	Five Years
TASC/TOC	1.078	1.140	1.075	1.134
Finance Structure	**High Risk IPP**		**Low Risk IPP**	
Capital Expenditure Period	Three Years	Five Years	Three Years	Five Years
TASC/TOC	1.114	1.211	1.107	1.196

5 Revision Control

Exhibit 5-1 Revision table

Revision Number	Revision Date	Description of Change	Comments
1	February 11, 2014	Document formatted	

6 References

1 Advancement of Cost Engineering (AACE) International. (2005) *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries; TCM Framework 7.3 – Cost Estimating and Budgeting*, AACE International Recommended Practice No. 18R-97, 2005, Rev. November 29, 2011
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3 Electric Power Research Institute (EPRI). (2009). *Technical Assessment Guide (TAG®) – Power Generation and Storage Technology Options*, Electric Power Research Institute (EPRI), EPRI Product ID No. 1017465, December 12, 2009.
Retrieved on April 8, 2011 from http://tag.epri.com/tag/

4 National Energy Technology Laboratory (NETL). (2011) Power Systems Financial Model Version 6.6. Pittsburgh, Pennsylvania. Details Retrieved on March 8, 2012, http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Source=Products&PubId=382