8 Financial Assumptions

This chapter presents the financial assumptions used in EPA Base Case v.4.10. The first section gives a summary of each of the key financial parameters. The remainder of the chapter presents an in-depth explanation of the theoretical underpinnings and methods used to develop the two most important financial parameters – the discount rate and capital charge rate.

8.1 Summary of Key Financial Parameters

8.1.1 Capital Charge Rate, Book Life, and Discount Rate for Capital Expenditures

EPA Base Case v.4.10 models a diverse set of generation and emission control technologies, each of which requires financing.[1] Table 8-1 presents the capital charge rate, discount rate, and book life assumptions for the technologies in base case v.4.10. As will be discussed more fully later in this chapter, the capital charge rate is used to convert the capital cost of a technology into a stream of levelized annual payments that ensure capital recovery. The discount rate is used to translate future cash flows into current dollars by taking into account factors (like inflation and the ability to earn interest), which make one dollar tomorrow worth less than one dollar today. The discount rate allows inter-temporal tradeoffs and represents the risk adjusted time value of money. The book life is the payback period on an investment.

There are several things to note about Table 8-1. The technology differentiated capital charge rates are used in v.4.10 to derive the associated capital charge rates shown in the table. However, while the technology-differentiated discount rates appearing in the table were used in deriving these capital charge rates, in EPA Base Case v.4.10 a single U.S. discount rate of 6.15% is used across all technologies.

[1] The capital charge rates discussed here apply to new (potential) units and environmental retrofits that IPM installs. The capital cost of existing and planned/committed generating units and the emission controls already on these units are considered “sunk costs” and are not represented in the model.

Table 8-1 U.S. Discount Rates and Capital Charge Rates in EPA Base Case v4.10

Investment Technology	Capital Charge Rate	Discount Rate	Book Life
Environmental Retrofits	11.3%	5.5%	30
Advanced Combined Cycle	12.1%	6.2%	30
Advanced Combustion Turbine	12.9%	6.9%	30
Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture[1]	14.1%	7.8%	40
Advanced Coal with Carbon Capture	11.1%	5.5%	40
Nuclear without Production Tax Credit (PTC)	10.8%	5.5%	40
Nuclear with Production Tax Credit (PTC)[2]	9.1%	5.5%	40
Biomass with ARRA Loan Guarantees[3]	9.3%	4.6%	40
Biomass without ARRA Loan Guarantees	11.1%	6.2%	40
Wind and Landfill Gas with ARRA Loan Guarantees[2]	10.1%	4.6%	20
Wind and Landfill Gas without ARRA Loan Guarantees	12.2%	6.2%	20
Solar and Geothermal with ARRA Loan Guarantees[2]	10.1%	4.6%	20
Solar and Geothermal without ARRA Loan Guarantees	12.2%	6.2%	20

Notes:
The discount rates appearing in the table were used in deriving these capital charge rates. However, as noted in the text, a single U.S. discount rate of 6.15% is used across all technologies in EPA Base Case v.4.10.
[1]The capital charge rate for these technologies includes a 3% climate change uncertainty adder. (See text.)
[2]The capital charge rate for this technology reflects the impact of the PTC provided under the Energy Policy Act of 2005. (See text.)
[3]The capital charge rate for these technologies reflects the impact of ARRA loan guarantees. (See text.)

Capital Cost Adder for Climate Change Uncertainty: Adopting the procedure followed in EIA's Annual Energy Outlook 2010, the capital charge rates shown in Table 8-1 for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle (IGCC) without Carbon Capture include a 3% adder to the cost of debt and equity (see section 8.2.3 for discussion of debt and equity). This capital cost adder reflects increased financing costs for investment decisions involving coal plants without carbon capture caused by uncertainty surrounding possible future climate change policies that could limit CO_2 emissions from the power sector

ARRA Loan Guarantees for Renewables and Biofuels: The American Recovery and Reinvestment Act (ARRA) of 2009 (Public Law 111-5) provides loan guarantees for renewables and biofuels. Following the procedure implemented in AEO 2010, these loan guarantees are reflected in a reduction of 2% in the cost of debt and equity for biomass, wind, landfill gas, solar, and geothermal technologies. Capital charge rates with and without the 2% reduction appear in Table 8-1 because the loan guarantees expires in 2016.

Energy Policy Act Production Tax Credit for Nuclear: The Energy Policy Act of 2005 (Sections 1301, 1306, and 1307) provides a production tax credit (PTC) of 18 mills/kWh for 8 years up to 6,000 MW of new nuclear capacity. The financial impact of the credit is reflected in the capital charge rate shown in Table 8-1 for "Nuclear with Production Tax Credit (PTC)."

8.1.2 ARRA Production and Investment Tax Credit (PTC and ITC) for Renewables

In addition to the loan guarantees that are reflected in the capital charge rates for renewables shown in Table 8-1, ARRA 2009 (Division B, Title I, Sec. 1101, 1102, and 1603) also provides extensions of the PTC and 30 percent ITC to renewables. These are represented in EPA Base Case, v.4.10 as a 30% reduction in the capital cost of these technologies in 2012.

8.1.3 Discount Rate for Non-Capital Expenditures

The discount rate for non-capital expenditures (e.g., annual fuel, variable operations and maintenance, and fixed operations and maintenance costs) in EPA Base Case v.4.10 is assumed to be 6.15%. This serves as the default discount rate for all non-capital expenditures.

8.1.4 Inter-temporal Allowance Price Calculation

Under a perfectly competitive cap-and-trade program that allows banking, the allowance price always increases by the discount rate between periods if affected sources have allowances banked between those two periods. This is a standard economic result for cap-and-trade programs and prevents sources from profiting by arbitraging allowances between two periods.

The EPA Base Case v.4.10 uses the default discount rate of 6.15 percent in computing the increase in allowance price for cap-and-trade programs when banking is engaged as a compliance strategy.

8.1.5 Nominal and Real Dollars

EPA Base Case v.4.10 uses real 2007 dollars as its real dollar baseline. See Chapter 2 for further discussion on how IPM uses the real dollars for inter-temporal analysis.

8.2 Development of the Financial Assumptions for EPA Base Case v.4.10

This section explains the method used to derive the capital charge rate and discount rate as well as the assumptions underlying these financial parameters.

8.2.1 Introduction

As noted in section 8.1, the discount rate and the capital charge rate are the two parameters that encapsulate the financing assumptions for an investment option in EPA Base Case, v.4.10. The discount rate allows inter-temporal tradeoffs and represents the risk adjusted time value of money. The capital charge rate is used to convert the capital cost into a stream of levelized annual payments that ensures capital recovery of an investment.

Discount Rate

The discount rate is a function of the following parameters:

- Capital structure (Share of Equity vs. Debt)
- Post-tax cost of debt (Pre-tax cost of debt*(1-tax rate))
- Post-tax cost of equity

The weighted average cost of capital (WACC) is used as the discount rate and is calculated as follows:

WACC = [Share of Equity * Cost of Equity]
+ [Share of Preferred Stock * Cost of Preferred Stock]
+ [Share of Debt *After Tax Cost of Debt]

The focal point is on debt and equity (common stock) because preferred stock is generally a small share of capital structures.

Capital Charge Rate

The capital charge rate is a function of the parameters that overlap in part with the discount rate, but also include parameters related to the amortization of capital:

- Capital structure (Debt/Equity shares of an investment)
- Pre-tax debt rate (or interest cost)
- Debt Life

- Post-tax Return on Equity (ROE) (or cost of equity)
- Other costs such as property taxes and insurance
- State and Federal corporate income taxes
- Depreciation Schedule
- Book Life

The capital charge rate is calculated by solving for earnings before interest, taxes, and depreciation (EBITDA) or pure operating earnings such that the project is able to recover the cost of equity as the internal rate of return over the lifetime of the project. The sum of discounted cash flows to the equity holders over the lifetime of the project, discounted at the cost of equity is set equal to the initial investment. The capital charge rate so calculated is defined as follows:

- Capital Charge Rate = EBITDA/Total Investment

In other words, the capital charge rate is the rate of return required on invested capital, resulting from pure operations.

8.2.2 Method for Deriving Discount Rate and Capital Charge Rate in EPA Base Case v 4.10

Introduction to Risk

The risk of an investment in the power sector is heavily dependent on market structure risks. The range of risks has increased due to deregulation which has resulted in approximately 35 percent to 40 percent of capacity being deregulated IPP (Independent Power Producer) capacity. For example, merchant IPP's selling into spot market have more market risk than regulated plants or IPP’s having long-term, known-price contracts with credit worthy counter parties. There are also technology risks and financing structure risks (corporate vs. project financings). Lastly, there is financial risk related to the extent of leverage.

The risk, especially to the extent it is correlated with overall market conditions, is an important driver of financing costs. Other risks are handled in the cash flows and are treated as non-correlated with the market. This emphasis on correlated market risk is based on the Capital Asset Pricing model and associated financial theory. This analysis takes into account differences in technology and market structure risks.

Differences between corporate and project financings are highlighted but no specific adjustment has been made for them.

Market Structure Risks

The power sector in North America can be divided into the traditional regulated sector (as known as “cost of service” sector) and deregulated merchant sector (as known as “competitive” sector).

- **Traditional Regulated** - The traditional regulated market structure is typical of the vertically integrated utilities where generation (and transmission and distribution, abbreviated T&D) investments are approved through a regulatory process and the investment is provided a regulated rate of return. Returns on investment in this form of market structure are cost plus regulated returns that are administratively determined. Returns are affected by market conditions due to regulatory lag and other imperfections in the process, but overall are less exposed to the market than deregulated investments, all else equal. In this report, we use the term “utility financing” to refer to this type of market structure. A closely related market structure is the situation where a plant is built under a power purchase agreement (PPA) with a utility with known pricing that allows for a very high degree of investment amortization during the contract period. In such an arrangement, the risks are more credit and performance related and much less market related.
- **Deregulated Merchant** - In a deregulated merchant market structure, investments bear the full or a very high degree of market risk as the price that they can sell electricity at is dependent on what the short-term markets will bear. Return on investment in this form of market structure is not only dependent on the state of the economy, but also on commodity

prices, as well as on capital investment cycles and remaining price related regulation, e.g., FERC price caps on capacity prices. The capital investment cycle can create a "boom and bust" cycle which imparts source risk or uncertainty to the sector. The operational cash flows from investments in this sector are more volatile as compared to in the traditional regulated sector, and hence, carry more business or market risk. In this report, we use the term "merchant financing" to refer to this type of market structure.

Technology Risks
The selection of new technology investment options is partially driven by the risk profile of these technology investments. For instance, in a deregulated merchant market, an investment in a combustion turbine is likely to be much more risky than an investment in a combined cycle unit because while a combustion turbine operates as a peaking unit and is able to generate revenues only in times of high demand, a combined cycle unit is able to generate revenues over a much larger number of hours in a year. An investor in a combined cycle unit, therefore, would require a lower risk premium than an investor in a combustion turbine.

Financing Structure Risks and Approach
While investments in new units differ based on market structure and technology risks, differences also may occur because of financing schemes available. There are two major types of financing schemes:

- Corporate finance is a category of financing where a developer raises capital on the strength of the balance sheet of a company rather than a single project. In this type of financing, the debtors have recourse to the entire company's assets.
- Project finance, as this category of financing is often labeled, allows developers to seek financing using only the project as recourse for the loan. For instance, a project developer may wish to develop a new combined cycle unit, but will seek to use project financing in such a way that if it defaults on the loan, debtors have recourse only to the project itself and not against the larger holdings of the project developer. This approach can be more risky than corporate finance, all else being equal, because there is less diversification than the corporation which can be thought as a collection of projects. However, there are some projects more suitable for project financing because: (1) they may have a self-sustaining revenue stream that is greater than the corporate average, or (2) risk is reduced through a long-term PPA with a credit worthy counterparty such as a vertically integrated utility or a regulated affiliate of a merchant company.

There are many benefits of a project financing structure but there are also costs associated with it. A project financing structure typically has higher transaction costs (and even higher debt costs as debt financing is largely privately placed), but it also solves some of the agency problems and underinvestment issues that corporate financed structures face1.

However, as noted above, this analysis does not make an effort to quantify the relative costs and benefits of one structure over the other. Rather, the approach used is based on the premise that regardless of financial structure, each project has its own risks based on market structure and technology. Further, because corporate financing is more observable than project financing2 and has evolved in the power sector to the level of making key risk inferences possible (e.g., IPP and utility stock trades), assessment of market correlated risks should be based on IPP and utility corporate financing.

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[1] For more information on project financing, see paper titled "The Economic Motivations for Using Project Finance" by Benjamin C. Esty, Harvard Business School, Feb 2003

[2]Project Financing data is less observable as it's not explicitly traded. Also, often key financing parameters are unavailable due to confidentiality reasons.

Approach to Market Structure Risk
In EPA Base Case 4.10, a hybrid financing model is used, i.e., it is assumed that future development activity would be roughly evenly split between utility financings and pure merchant financings. This is designed to reflect a shift in the market in ownership and risk profiles for power generation assets, and recent development trends and emphasis on long term contracts3. In this approach, for modeling purposes, we assume that new units are financed as a weighted average of utility and merchant financing parameters. For new units we assume that both utility and merchant components get equal weights. For retrofits, we assume that utility component gets 2/3 and merchant component gets 1/3 weight4.

- Example 1: The debt to equity capital structure of a combustion turbine is 55/45 under utility financing and 30/70 under merchant financing. Under the assumption that utility and merchant components get equal weights, the debt to equity ratio under hybrid financing is D = (55 + 30)/2 = 42.5 / E = (45 + 70)/2 = 57.5.
- Example 2: The debt to equity capital structure of a retrofit is 55/45 under utility financing and 45/55 under merchant financing. Under the assumption of a 2/3, 1/3, utility/merchant weighting, the debt to equity ratio under hybrid financing is D = (55 * 2/3) + (45 * 1/3) = 51.6 / E = (45 * 2/3) + (55 * 1/3) = 48.3. A full summary for all technologies appears in Table 8-2 below.

Capital Charge Rate – A More Detailed Description
The capital charge rate is calculated by solving for earnings before interest, taxes, and depreciation (EBITDA) or pure operating earnings such that the project is able to recover the cost of equity as the internal rate of return over the lifetime of the project. The sum of discounted cash flows to the equity holders over the lifetime of the project, discounted at the cost of equity is set equal to the initial investment. The capital charge rate so calculated is defined as follows:

Table 8-2 Capital Structure Assumptions for EPA Base Case v4.10

Technology	Utility	Merchant	Hybrid
Combustion Turbine	55/45	30/70	42.5/57.5
Combined Cycle	55/45	45/55	50/50
Coal & Nuclear	55/45	60/40	57.5/42.5
Renewables	55/45	45/55	50/50
Retrofits	55/45	45/55	51.7/48.3

- Capital Charge Rate = EBITDA/Total Investment

In other words, the capital charge rate is the rate of return required on invested capital, resulting from pure operations.

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[3]An alternate approach is to categorize the United States into the two previously discussed financial regions – Cost-of-service and competitive. The cost-of-service region will have capital charge rates based on utility financial assumptions and the competitive region will have capital charge rates based on merchant financial assumptions. Such an approach could result in overbuilding in the cost-of-service region due to lower capital charge rates in the absence of regulatory prohibitions or external sales. This is similar to the public vs. IOU financing arbitrage problem, i.e. what stops government utilities from supplying all power? In fact, there are formal and informal limits, and because fully characterizing these limits is extremely complex, a hybrid approach is used.

[4]Retrofits are largely associated with coal fired plants and most coal fired plants are currently owned and operated by utilities in a "utility financing" structure. Moreover, since the magnitude of the retrofit investment is not as large as a plant investment, the financing of a retrofit is more likely to happen from a firm's internal cash flows instead of external financing.

The discounted cash flow to the equity holders of the project is characterized in terms of the Free Cash Flow to Equity (FCFE). FCFE is a valuation technique to estimate cash flows paid to the equity shareholders of a company after all expenses, reinvestment, and debt repayment have been made. The FCFE approach is suited for valuation of assets that have finite economic lives and where debt levels vary from year to year. In the FCFE approach, it is assumed that the asset has a finite life and debt reduces over time based on a mortgage-style repayment structure.

Specifically the cash flows to the equity5 are calculated as follows:

Cash Flows to Equity = EBIT (1-tax rate)
- Interest (1-tax rate)
+ Depreciation
- Capital Expenditures
- Working Capital Change
- Principal Payments
+ New Debt Issued

Discount Rates and Capital Charge Rates

Based on the above approach, the discount rates and capital charge rates summarized in Table 8-1 above were obtained for investments in the U.S. The procedures and assumptions used to calculate the rates in Table 8-1 are discussed in the sections below.

8.2.3 Calculation of the Hybrid Capital Charge Rates

ROE

The first step was the calculation of a return on equity (ROE) using an average ROE under utility financing (10.3%) and merchant financing (15.2%) assuming a 50:50 debt/equity ratio. This resulted in a ROE of 12.75%6. This ROE is kept the same across each technology7 but the risk differences across technologies are implemented through the capital structure. See the discussion of capital structures in this subsection under “Debt Equity Share” and the discussion of “Debt and Equity Shares and Technology Risk” in section 8.2.4.

Note that a 50:50 mix (corresponding to the hybrid capital structure for a combined cycle – see Table 8-2) has been chosen. This is because we assumed that the overall IPP risk was on average reflective of the risk profile of combined cycle units which in turn was assumed to be intermediate between base load and peaking. The combined cycle technology is considered to have “average” market risk being an intermediate type technology. Also, in the aggregate, the five selected IPP companies[8] have more combined cycle capacity in their supply mix than any other technology. Additionally, going forward, it is expected that gas will continue to play an increasingly important role in the supply mix of both utilities and merchant companies, with combined cycle technology playing a dominant role. For all of these reasons, it was considered appropriate to use the ROE corresponding to a combined cycle facility.

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[5]An alternative definition of free cash flow to equity is as follows: Net Income + Depreciation – capital expenditures – working capital change – Principal Payments + New Debt Issued

[6]The Pennsylvania-New Jersey-Maryland Interconnection (PJM) uses a 12% ROE for a combined cycle at a 50:50 debt/equity ratio to calculate the cost of new entry (CONE) for their capacity markets. Hence, the estimates are fairly close to those used by a major RTO.

[7]Even though ROE is kept the same across all technologies, it doesn’t mean that the market risks are considered the same for each technology. See capital structure discussion in the next paragraph.

[8]Our merchant parameters are derived from market observations of five IPP companies – see discussion on development of merchant financed parameters.

Debt Equity Share
Second, the capital structures (D/E)9 for the various technology types were calculated using an average of utility and merchant financing. The utility debt capacity (and returns) is assumed to be independent of technology type based on the theoretical assumption that regulation will provide an average return to the entire rate base. The merchant debt capacity is based on market risk where a base load plant is likely to have a higher debt capacity than a combustion turbine plant. Table 8-2 presents the capital structure assumptions used in EPA Base Case v4.10.

The risk differences across technologies are implemented by varying the capital structure. As shown in Table 8-2 and discussed above, a peaking unit such as a combustion turbine is estimated to have a capital structure of 42.5/57.5 while a base load unit such as nuclear and coal is assumed to have a capital structure of 57.5/42.5. This is based on the intuition that less risky technologies can carry more leverage. As debt is less expensive than equity, this will automatically translate into a lower capital charge rate (and a lower discount rate) for base load technologies and a higher capital charge rate (and a higher discount rate) for peaking technology, assuming other components of the capital charge rate calculation remain the same.

Cost of Debt
Third, the cost of debt was adjusted to reflect the average cost of debt for utility and merchant financings for each technology. The utility cost of debt is assumed to be the same across all technologies while the merchant cost of debt is higher than utility and is higher for a combustion turbine unit than for a combined cycle or a coal plant. Table 8-3 summarizes the debt rates used in EPA Base Case v4.10.

Table 8-3 Debt Rates for EPA Base Case v4.10

Technology	Utility	Merchant	Hybrid
Combustion Turbine	6.25%	9%	7.63%
Combined Cycle	6.25%	8%	7.13%
Coal & Nuclear	6.25%	8%	7.13%
Wind	6.25%	8%	7.13%
Retrofits	6.25%	8%	6.83%

These financing parameters were then combined with taxation assumptions and technology specific assumptions on depreciation, book life and debt life to yield the capital charge rates outlined in Table 8-1 above.

8.2.4 Development of Merchant Financing Parameters

Merchant ROE
The Independent Power Producer (IPP) return on equity parameter was estimated to be 15.2%[10]. This was based on empirical analysis of stock price data of five pure play comparable merchant generation companies, namely Reliant, NRG, Dynegy, Mirant, and Calpine. First, levered betas[11] (a measure of total corporate risk which includes business and financial risk) for the five companies were calculated using five years of historical stock price data. Second, unlevered betas (a measure of business risk, i.e., those affected by a firm’s investment decisions) were

[9]A project’s capital structure is the appropriate debt capacity given a certain level of equity, commonly represented as “D/E,” i.e., debt/equity. The debt is the sum of all interest bearing short term and long term liabilities while equity is the amount that the project sponsors inject as equity capital.

[10]Merchant ROE, as additionally observed by EIA, have risen over time.

[11]Levered beta is directly measured from the company’s stock returns with no adjustment made for the debt financing undertaken by the company. It is also known as equity beta. Hence, levered beta incorporates both business and financing risk undertaken by the company.

calculated using the estimated levered beta, the companies' market debt/equity ratio, and the riskiness of debt. As most comparables historically had periods of financial distress, the unlevering[12] approach was modified to include the riskiness of debt, instead of purely using the Hamada equation.[13] The unlevered betas were then relevered[14] at the target debt/equity ratio of 50/50 to get the relevered equity betas and return on equity. The return on equity was determined using the Capital Asset Pricing Model (CAPM).

The CAPM parameters used to estimate the ROE are as follows:

- Risk Free Rate based on 20 year T bond rate: 4.9%[15]
- Market Risk Premium 1926-2006[16:] 7.1%
- Size Premium: 0.65%[17]

The estimation of the IPP ROE described here is fairly close to what EIA has published. EIA estimates a 2010 ROE of roughly 14.8% at a D/E ratio of 45/55 and increasing to approximately 16% by 2012.[18]

Merchant Cost of Debt
The cost of debt for the merchant sector was computed assuming an average 3-month LIBOR (London Interbank Offered Rate) of 4.9-5% and an average spread of 3% reflecting the low medium grade or low grade nature of merchant bonds. An additional one percent spread was assumed for combustion turbine units due to the high price risk for combustion turbine units.

Debt and Equity Shares and Technology Risk
The capitalization structure for merchant financings was estimated to be 45/55 based on empirical analyses. This capitalization structure was assumed to be on average reflective of the combined cycle for reasons discussed earlier in this document.

Each generation technology was considered to have its own risk profile. Some evidence indicated that the greater the base load share, the lower the asset risk. This is consistent with having revenues that are more related to variable cost advantages as well as the value of capacity as opposed to peaking units which are more dependent on scarcity or capacity revenue, which, in turn, has very high systemic risk.

There are two main mechanisms for reflecting the greater risk for peakers and the lower risk for base load. First, the ROE could have been adjusted such that for a given target leverage, the ROE would be higher for peakers, and lower for base load. For example, an unlevered beta and

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[12]The unlevering process removes a company's financing decision from the beta calculation. The calculation therefore, attempts to isolate the business (operating risk) of the firm.

[13]The Hamada equation is described at http://www.answers.com/topic/hamada-equation as "A fundamental analysis method of analyzing a firm's costs of capital as it uses additional financial leverage, and how that relates to the overall riskiness of the firm. The measure is used to summarize the effects this type of leverage has on a firm's cost of capital (over and above the cost of capital as if the firm had no debt)."

[14]The relevering process estimates the levered beta of the firm given a target capital structure and the pure business risks of the firm as determined from the unlevering process

[15]Federal Reserve Statistical Release (H15 data), May 2007

[16]Source: Stocks, Bonds, Bills, and Inflation, 2007 Yearbook Valuation Edition, Morningstar/Ibbotson's Associates

[17]Source: Stocks, Bonds, Bills, and Inflation, 2007 Yearbook Valuation Edition, Morningstar/Ibbotson's Associates

[18]See Electricity Market Module of NEMS, EIA Annual Energy Outlook, May 2009

ROE (which assumes zero leverage) could have been calculated using the risk differentiated capital structures and then relevered at some target leverage. This would have yielded a different ROE for each technology but the same capital structure across all technologies.

The second option was to keep the same ROE while varying the capital structure. This was the adopted approach. Thus, even though the leverage of peakers was lowered, the ROE was not lowered. This raised the weighted average cost of capital and the resulting capital charge rate. This effectively also raised the unlevered beta for peakers relative to combined cycle. For base load, leverage was raised without raising ROE, effectively lowering the unlevered beta and the cost of capital.

8.2.5 Development of Utility Financing Parameters

Utility ROE

The utility return on equity was calculated to be 10.3%. This was based on empirical analysis of correlation of returns on the S&P utility Index vs. the broader S&P 500 market index for the last five years to determine the levered beta and then unlevering and relevering based on a process similar to that for merchant sector. The ROE is also consistent with what state commissions have awarded the shareholder-owned electric utilities recently.[19]

Utility Cost of Debt

The cost of debt for the utility sector was estimated to be 6.25%. The utility bonds were categorized into various credit rating rungs based on information obtained from the Edison Electric Institute.[20] Historical yields were analyzed for the various rungs based on data obtained from Bloomberg. A weighted average cost of debt was then determined based on the historical yields and percentages of utility credit rating classes. The estimated value was also corroborated against the yield to maturity of Moody's average utility bond index.

Debt and Equity Shares

The target capitalization structure for utilities was determined using US utility capitalization ratios derived from Bloomberg data. Similar CAPM parameters were used to estimate the ROE of the utility sector. The capitalization structure for utility financings was estimated to be 55/45 based on empirical analyses and this capitalization structure was assumed to be on average reflective of all technologies.

Technology Risks

For the utility financing, we assumed that the required returns for regulated utilities are independent of technology. This assumption was a simplifying assumption, and further empirical work may be warranted here.

8.2.6 Development of Other Parameters

Taxation and Insurance Costs

Corporate and State Income Taxes: The maximum US corporate income tax rate is 35%.[21] State taxes vary but on a national average basis, the state taxes are 6.50%.[22] This yields a net effective tax rate of 39.3%.

[19]See page 35, 2006 Financial Review, Annual Report of the U.S Shareholder Owned Electric Utility Industry

[20]2006 Financial Review, Annual Report of the U.S Shareholder Owned Electric Utility Industry

[21]Internal Revenue Service, Publication 542.

[22]Population weighted average based on 2008 state taxes information available at Federation of Tax Administrators, ttp://www.taxadmin.org/fta/rate/corp_inc.html.

State Property Taxes: US state property taxes are approximately 0.9% based on a national average basis. This is based on extensive primary and secondary research conducted by ICF using property tax rates obtained from various state agencies.

Insurance Costs: Insurance costs are approximately 0.3%. This is based on estimates of insurance costs on a national average basis.

Inflation
The inflation rate of 2.25% is based on an assessment of implied inflation from an analysis of yields on 5 year and 10 year Treasury securities and Treasury Inflation Protected Securities (TIPS).

Book life, Debt Life and Depreciation
Table 8-4 presents a summary of various assumed lives at the national level.

Table 8-4 Book Life, Debt Life and Depreciation Schedules for EPA Base Case v. 4.10

Technology	Book Life (Years)	Debt Life (Years)	US - MACRS Depreciation Schedule
Combined Cycle	30	20	20
Combustion Turbine	30	15	15
Coal Steam and IGCC	40	20	20
Nuclear	40	20	15
Solar and Geothermal	20	20	5
Biomass	40	20	7
Wind and Landfill Gas	20	20	7
Retrofits	30	20	20

Book Life or Useful Life of Plant:
The book life or useful life of a plant was estimated based on researching financial statements of utility and merchant generation companies. The financial statements[23] typically list the period over which long lived assets are depreciated for financial reporting purposes. The research conducted broadly supports the numbers outlined in the table above.

Debt Life: The debt life is assumed to be on a 20 years schedule except in the case of combustion turbine where debt life is lower.

Depreciation Schedule:
The US MACRS[24] depreciation schedules were obtained from IRS Publication 946[25] that lists the schedules based on asset classes. The document specifies a 5 years depreciation schedule for wind energy projects and 20 years for Electric Utility Steam Production plants. These exclude combustion turbines which have a separate listing at 15 years. Nuclear Power Plants are separately listed at 15 years as well.

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[23]SEC 10K filings of electric utilities and pure merchant companies. For example, Calpine's 10K lists 35 years of useful life for base load plants, DTE energy uses 40 years for generation equipment; Dynegy gives a range of 20-40 years for power generation facilities; Mirant reports 14-35 years for power production equipment; Reliant: 10-35 years

[24]MACRS refers to the Modified Accelerated Cost Recovery System, issued after the release of the Tax Reform Act of 1986. It allowed faster depreciation than with previous methods.

[25]IRS Publication 946, "How to Depreciate Property", Table B-2, Class Lives and Recovery Periods.