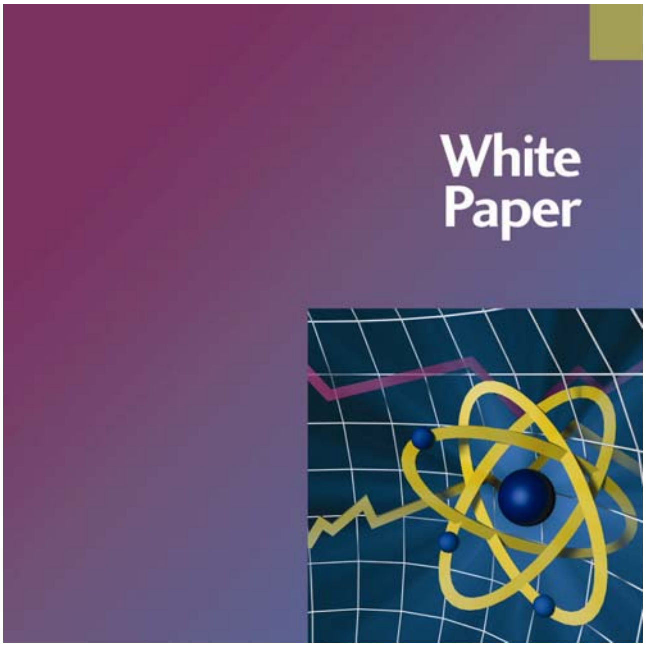


February 2009

The Cost of New Generating Capacity in Perspective

Executive Summary

Like all new generating capacity, there is considerable uncertainty about the capital cost of new nuclear generating capacity. Credible estimates of overnight capital costs range from $2,400/kWe to as much as $4,540/kWe. This wide variation in costs can be attributed to several factors:

- uncertainty about escalation of commodity prices and wages,
- the fact that design work is not complete and, until it is, it will be impossible to produce a precise cost estimate, and
- some early estimates did not include all the costs involved in the construction of a power plant (see "Understanding the Cost Components of New Generating Capacity," page 4).

While these costs are daunting, it is important to recognize that capital costs are only the starting point for any analysis of new generating capacity. A more accurate measure of economic competitiveness, and one that is more important to regulators and consumers, is the cost of electricity produced by a particular project compared to alternative sources of electricity and to the market price of electricity when the power plant starts commercial operation. This generation cost takes into account not only capital and financing costs, but also the operating costs and performance of a project.

Analysis by generating companies, the academic community, and financial experts shows that even at capital costs in the $4,000/kWe to $6,000/kWe range, the electricity generated from nuclear power can be competitive with other new sources of baseload power, including coal and natural gas. These results are absent any restrictions on carbon dioxide emissions. With regional or national programs that put a significant price on carbon emissions, nuclear power becomes even more competitive.

NEI
NUCLEAR ENERGY INSTITUTE

1776 I Street, N.W. ■ Suite 400 ■ Washington DC, 20006-3708
www.nei.org

Recent Cost Estimates for New Nuclear Power Plants

Although there is uncertainty about the capital cost of new nuclear generating capacity, recent filings with state Public Utility Commissions (PUCs), and negotiations on engineering, procurement and construction (EPC) contracts are beginning to narrow the range. A more accurate picture of these costs is developing.

Florida Power and Light Company (FP&L). In October 2007, FP&L filed a Petition for Determination of Need with the Florida Public Service Commission (PSC) for two new nuclear units at its Turkey Point site. The petition was approved in March 2008. FP&L provided a non-binding estimate for overnight capital costs of between $3,108/kWe and $4,540/kWe (2007 dollars), depending on the cost of materials escalation, owner's scope and cost, and transmission integration required. FP&L based its estimate on an earlier study done by the Tennessee Valley Authority (TVA) for its Bellefonte site, adjusted for site-specific factors and elements not included in the TVA study.

"For eight of the nine scenarios evaluated, the addition of new nuclear capacity is economically superior ..."

These estimates for overnight capital cost result in a range of total project costs for two units between $12.1 billion and $24.3 billion in "year spent dollars",[1] depending on the plant design FP&L selects.[2] The total project cost includes escalation of 2.5 percent and allowance for funds used during construction (AFUDC) calculated at a rate of 11.04 percent.[3]

In its filing, FP&L also evaluated the comparative economics of two other competing technologies: natural gas combined cycle and coal integrated gasification combined cycle (IGCC). FP&L looked at nine economic scenarios incorporating a range of potential fossil fuel prices and environmental compliance costs. The conclusion:

> "FPL's analysis shows that for all of the scenarios evaluated (eight of nine), the addition of new nuclear capacity is economically superior versus the corresponding addition of new CC [combined cycle] units required to provide the same power output, yielding large direct economic benefits to customers …. In fact, in the only scenario in which nuclear is not clearly superior, the natural gas prices are significantly lower than they are today and there are zero future economic compliance costs for CO_2 emissions. Of all the scenarios evaluated, FPL believes these two to be the most unlikely. Moreover, even in these two unlikely scenarios, the results of the analysis show nuclear to be competitive or only slightly disadvantaged economically, while retaining the non-quantified advantages of fuel diversity, fuel supply reliability, and energy independence."

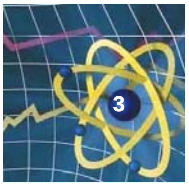
Progress Energy Florida filed a Petition for Determination of Need with the Florida PSC in March 2008 for its proposed Levy nuclear power plant. The petition was approved in July 2008. Progress' non-binding overnight cost estimate

---

[1] Year spent dollars are escalated to the year in which spending occurs.

[2] FP&L is considering the Westinghouse AP1000 (1,100 MWe) and the GE ESBWR (1,520 MWe).

[3] AFUDC is the accumulated cost of the borrowed funds used during construction. The AFUDC rate is generally equal to the weighted cost of capital for the project. See "Financing New Generating Capacity Under Rate-of-Return Regulation," page 5.



for its two-unit greenfield site is $4,260/kWe (2007 dollars).[4] This results in a total project cost of $14.0 billion (year spent dollars) for two units, including project escalation of 3.0 percent and projected AFUDC of $3.2 billion.

This initial estimate does not include the cost of transmission system upgrades, which will be necessary to accommodate the new units. Progress currently estimates that these upgrades will cost approximately $2.4 billion, excluding AFUDC.

Progress compared the proposed nuclear units with other viable generation alternatives. Nuclear, pulverized coal and atmospheric fluidized bed combustion (AFBC) and coal IGCC were evaluated against an all natural gas generation reference case:[5]

"When one analyzes the nuclear project over sixty years, and takes into account air emission compliance cost, fuel diversity, and fossil fuel dependence concerns ... nuclear is generally more cost-effective."

> "Nuclear generation technology fared better than AFBC, pulverized coal and coal gasification against the all natural gas reference case in preliminary evaluations. Further, nuclear generation appeared to be the most viable generation alternative to natural gas generation because (1) significant, potential environmental costs were associated with AFBC, pulverized coal and coal gasification resulting from GHG and possible carbon capture or carbon abatement costs, and (2) there were recent regulatory and utility decisions to forego AFBC, pulverized coal and coal gasification generation options in Florida."

Progress also found that, when evaluated over their expected 60-year operating lives, Levy 1 & 2 were more economic than an all-natural gas scenario:

> "When one analyzes the nuclear project over sixty years, and takes into account the air emission compliance cost, fuel diversity, and fossil fuel dependence concerns that the Florida Legislature requires the utility to consider, nuclear is generally more cost-effective than an all natural gas resource plan…"

South Carolina Electric & Gas (SCE&G). In May 2008, SCE&G applied to the South Carolina PSC for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order to construct two additional units at its V.C. Summer Nuclear Station. SCE&G and Santee Cooper, a state-owned electric and water utility in South Carolina, are joint owners of the existing V.C. Summer plant, and will share costs and generating output of the two new units. In addition, SCE&G and Santee Cooper have signed an EPC contract with Westinghouse Electric Company and Stone & Webster for the design and construction of the two units.

SCE&G estimates its portion of the total project cost (55 percent) for the two units at $6.3 billion. This includes project escalation[6] and AFUDC of $264 million, calculated at a rate of 5.52 percent. Assuming Santee Cooper's portion of

(Continued on page 6)

[4] Average for two units, based on a summer capacity rating of 2,184 MWe for two Westinghouse AP1000 units.

[5] Natural gas generation, based on relative capital costs, experience with the technology and environmental factors, was considered the default supply-side generation alternative to the other viable generation resources.

[6] SCE&G's project cost escalation rate is confidential.

Understanding the Cost Components of New Generating Capacity

An accurate analysis of the cost of new generating capacity requires an understanding of precisely what is included in any given set of numbers, particularly when making comparisons between generating technologies. The cost of a new power plant is made up of three major elements:

- capital costs (the cost of the equipment, materials and labor required to build the plant)
- financing costs, and
- operating costs.

The capital and financing costs make up the total project cost. The cost of electricity from a new power plant includes these costs, as well as the cost of operating the facility.

New power plant costs are often referred to as **overnight** costs. Overnight cost literally represents the cost to complete a construction project overnight. It usually includes **engineering-procurement-construction (EPC) costs**[1] and **owner's costs**[2], but is net of financing costs and does not account for inflation or escalation.

Capital cost estimates can be misleading unless it is clear what assumptions stand behind them. They may or may not include contingencies to account for factors such as project complexity, design status, market conditions or first-of-a-kind technologies. They can also represent the cost for more than one unit. These assumptions can account for differences of hundreds of millions of dollars.

The total cost of a power project should include all capital costs, contingencies and financing costs. Financing costs will depend on the rate obtained on the debt, project leverage, and whether the plant is built as part of a regulated entity's rate base or as an unregulated plant. Some projects may obtain more favorable financing terms through federal loan guarantees or state policies to recover carrying costs through rates during construction. Total project cost may also include escalation to inflate costs to the value of the year in which the dollars will be spent[3].

The total cost of a power project is also reflected in the cost of electricity produced by the plant or the "busbar" cost. It includes the capital and financing costs for the project as well as the cost of operation, maintenance and fuel once the plant is producing power. It also includes the return on equity investment in the project.

---

[1] EPC costs include the cost of engineering, materials and labor for the construction of the power plant.

[2] Owner's costs include other infrastructure – transmission upgrades, cooling towers, water intake and treatment systems, administrative buildings, warehouses, roads, switchyards, as well as project management and development costs, permitting, taxes, legal, staffing and training.

[3] Costs expressed in 2015 dollars will be greater than the same costs expressed in 2007 dollars because of the time value of money.

Financing New Generating Capacity Under Rate-of-Return Regulation

Many states regulate the generation, transmission, and distribution of electricity. In these states, public utility commissions (PUCs) control electricity prices by regulating a utility's allowed costs and rate of return on investment. Electricity rates are determined such that utilities can recover their investments and operating costs and provide a reasonable return on equity to their investors. Rate-of-return regulation can be summarized using the following equations:

(rate of return) x (rate base) = (utility's return)

(electricity price) x (electricity sold) [1] = (rate base) [2] + (utility's return) + (operating costs)

The **rate base** is a measure of the value of the utility's prudent capital investments. The utility's allowed return to its investors is equal to the **rate of return** set by the PUC times the utility's rate base. The utility will charge an electricity price that generates revenues to cover the rate base (its investments), its allowed return, and its operating costs.

When an electric company builds a new power plant, large upfront investment is required. In most regulated states, utilities recover the interest on the debt and the return on equity associated with this upfront investment through rates. The interest cost and equity return or "carrying costs" can be capitalized, added to the rate base, and recovered in rates when the plant goes into operation and is deemed "used and useful." The accumulated costs are called "allowance for funds used during construction" or **AFUDC**.

Before capital investment and operating costs can be passed onto electric customers through rates, the PUC must determine that they were prudently incurred. PUCs review the costs being added to the rate base during rate cases and during periodic prudence reviews. A PUC can disallow the recovery of costs that are deemed extravagant or imprudent.

In some regulated states, utilities are allowed to recover the carrying costs of capital investments in rates during construction. This type of rate arrangement is often referred to as construction work in progress or **CWIP**.[3] Florida is one of several states that allows CWIP for utilities investing in new nuclear power. CWIP supports the construction of new generating capacity in several ways. It reduces the financing costs paid by a utility (and ultimately its customers), since the carrying costs are not accumulated and capitalized. It also improves utility cash flows, since the inclusion of CWIP in rates during construction means an immediate recovery of interest payments and an equity return. Most importantly, it reduces rate shock for consumers by minimizing financing costs and by gradually introducing rate increases during construction, instead of all at once when the plant goes into operation. According to NEI's modeling, CWIP reduces the first-year busbar cost of electricity for a nuclear plant by 20 to 30 percent.

[1] For simplicity, utility revenue is expressed as a single electricity price times the quantity of electricity generated. In reality, electricity prices differ by class (residential, industrial, commercial) and sometimes include pass-throughs for items such as fuel and public benefits.

[2] Investments for a new power plant are capitalized over the expected life of the plant. The depreciable portion of the rate base is recovered through rates each year.

[3] "Construction work in progress" is simply the capital investment made during construction; however this term is often loosely applied to the rate arrangement described above.

Nuclear Cost Estimates from Recent Public Utility Commission Filings			
Company	**Plant Capacity (MWe)**	**Overnight Capital Cost ($/kWe)**	**Total Project Cost (Billion $)**
FP&L	2,200 – 3,040	3,108 – 4,540	12.1 – 24.3
Progress	2,200	4,260	14.0
SCE&G/Santee Cooper	2,200	–	11.5*

** Estimate based on SCE&G's 55 percent share of total project cost*

total project cost is roughly proportional, the total for the two units is estimated at $11.5 billion (year spent dollars).

Since SCE&G has executed an EPC contract, its application offers some insight into a company's options for hedging against the risk of escalation in materials costs:

> "More than fifty percent (50%) of the total EPC contract cost is subject to Firm/Fixed pricing. An additional percentage of the contract cost projection may be converted to Fixed/Firm in future months upon acceptance by SCE&G of Fixed/Firm quotes from Westinghouse/Stone & Webster."

EPC scope is divided into one of three categories: fixed, firm and "actual costs." Under SCE&G's contract, cost elements subject to fixed pricing have no associated escalation rates, while firm elements are subject to definite established escalation rates. For example, one class of costs, called "Firm with Indexed Escalation," will be priced subject to the Handy-Whitman All Steam Generation Plant Index, South Atlantic Region.[7] This type of pricing offers some certainty as to what the actual cost for those elements will be. As a result, SCE&G applies a relatively low risk contingency[8] of 5 percent to these cost elements.

Cost elements such as craft wages, non-labor costs, time and materials, owners' costs and transmission costs will be paid at "actual costs" – meaning SCE&G will be exposed to real escalation associated with those costs. For planning purposes, SCE&G uses the Handy-Whitman index to estimate these costs, but there is significantly less certainty that estimates will reflect actual costs. Thus for craft wages, SCE&G assumes a "high risk" and assigns a 20 percent cost contingency. Non-labor costs, time and materials, owners' costs and transmission are all "moderate-high risk" and are assigned a 15 percent contingency.

Like FP&L and Progress, SCE&G analyzed a number of strategies for meeting South Carolina's electricity needs. The analysis compared a nuclear, natural gas, and coal strategy,[9] and examined various environmental compliance and

[7] A common escalation index for power plant materials and labor.
[8] Project contingency accounts for unexpected cost increases and is usually expressed as a percentage of the cost. Elements such as project complexity, design status, and market conditions all factor into the contingency.
[9] Both the nuclear and the coal strategies include gas capacity in the form of combustion turbine peaking units.

fuel prices. In all cases, SCE&G found nuclear to be the most competitive option over the long run:

> "… It can be seen that the gas strategy would cost SCE&G's customers $15.1 million per year more than the nuclear strategy if CO2 costs $15 per ton in 2012 and escalates at 7% per year. With CO2 at $30 per ton, the cost advantage of nuclear would be $125.2 million per year. A higher natural gas price with CO2 at $15 per ton shows a nuclear cost advantage of $68.5 million per year."

Although it had the highest capital cost, the new nuclear capacity produced the lowest-cost electricity, except for gas-fired combined cycle capacity without carbon capture and storage (assuming a gas price of $7.14/million Btu).

Even in scenarios with assumptions that are unfavorable to nuclear energy, nuclear is considered the optimal strategy:

> "…if uranium fuel prices follow a high track, the nuclear strategy still has a positive advantage over the gas strategy by $13.2 million per year but if natural gas prices follow a low track, then the gas strategy has the advantage over nuclear by $44.9 million per year. Additionally, if there is no legislation imposing additional costs on CO2 emissions, the gas strategy has an $86.5 million advantage over nuclear. However while higher uranium prices are possible, they are not expected. In addition, it does not seem reasonable at this point to expect low gas prices or no CO2 legislation."

Connecticut Integrated Resource Plan (IRP). In January 2008, the Brattle Group, under contract to Connecticut Light and Power and United Illuminating, published an IRP for the state of Connecticut. The IRP assumed an overnight capital cost for new nuclear of $4,038/kWe (2008 dollars). The resource plan also assumed $2,214/kW for supercritical coal, $4,037/kW for supercritical coal with carbon capture and storage (CCS), $2,567/kW for IGCC, $3,387/kW for IGCC with CCS, $869/kW for combined cycle gas, and $1,558/kW for combined cycle gas with CCS.

In the base case, new nuclear capacity produced a levelized cost of $83.40/megawatt-hour. Supercritical coal was at $86.50/MWh; supercritical coal with CCS at $141.90/MWh; IGCC at $92.20/MWh; IGCC with CCS at $124.50.MWh; gas combined-cycle (CC) at $76.00/MWh; and gas CC with CCS at 103.10/MWh. Although it had the highest capital cost, the new nuclear capacity produced the lowest-cost electricity, except for gas-fired CC capacity without CCS.[10] The Brattle Group ran four additional scenarios reflecting different fuel costs, CO2 prices, and technology costs with similar results: new nuclear capacity produced the lowest-cost electricity except for combined-cycle gas without CCS.

Connecticut is a member of the Regional Greenhouse Gas Initiative (RGGI), so all four scenarios (including the base case) assumed controls on carbon. Given the state's high dependence on natural gas for power generation, the Brattle Group suggested that "state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such [nuclear] baseload capacity."

Congressional Budget Office (CBO). In May 2008 CBO published "Nuclear Power's Role in Generating Electricity," a report assessing the competitiveness of nuclear power compared with other sources of new capacity to generate

[10] The average gas price in the base case scenario is $7.14/mmBtu (2008 dollars).

Brattle Group Analysis of Generating Costs							
	Nuclear	**SCPC**	**SCPC w/CCS**	**IGCC**	**IGCC w/CCS**	**Gas CC**	**Gas CC w/CCS**
Capital Cost ($/kWe)	4,038	2,214	4,037	2,567	3,387	869	1,558
Levelized Cost ($/MWh)	83.40	86.50	141.90	92.20	124.50	76	103.10

SCPC = supercritical pulverized coal; CCS = carbon capture and storage; IGCC = integrated gasification combined cycle; CC = combined cycle

electricity. The report focused primarily on the possible effects of constraints on carbon dioxide emissions and the impact of the incentives included in the Energy Policy Act of 2005 (EPAct).[11] In its reference scenario, CBO assumed overnight capital costs of $2,358/kWe for nuclear; $1,499/kWe for conventional coal; $685/kWe for conventional natural gas; $2,471/kWe for innovative coal (w/CCS); and $1,388/kWe for innovative natural gas (w/CCS).

CBO compared the technologies on a levelized cost basis and found that excluding carbon dioxide legislation and EPAct incentives, new nuclear capacity is cheaper than innovative coal and natural gas but is more expensive than conventional fossil capacity. However, it found that carbon dioxide constraints would have a significant impact on nuclear energy's competitiveness:

> "In the absence of both emissions charges and EPAct incentives, conventional fossil-fuel technology would dominate nuclear technology. But, even without EPAct incentives, if lawmakers enacted legislation that resulted in a carbon dioxide charge of $45 per metric ton nuclear generation would most likely become a more attractive investment for new capacity than conventional fossil-fuel generation. If the cost of emitting carbon dioxide was between $20 and $45 per metric ton, nuclear generation as an option for new capacity would probably be preferred over coal but not natural gas."

CBO also found that new nuclear capacity could be competitive at even lower carbon dioxide charges if the price of natural gas rose above the price assumed in the reference scenario ($6.26/mmBtu) or if the construction cost reductions predicted by the reactor designers were accurate. CBO found that in a high gas price environment of $12/mmBtu (near present-day prices), natural gas would no longer be competitive with new nuclear:

> "At the highest prices for natural gas considered in CBO's analysis of market and policy uncertainties, utilities would be extremely unlikely to prefer natural gas to either existing coal plants or new nuclear plants."

[11] EPAct incentives include Nuclear Power 2010, FutureGen, loan guarantees for innovative low-emitting technologies, nuclear delay insurance, the investment tax credit for innovative coal, the production tax credit for nuclear, renewal of the Price-Anderson liability program, and preferential tax treatment for nuclear decommissioning funds.

The CBO report also shows that EPAct incentives, such as the nuclear production tax credit and federal loan guarantee, could make the first few nuclear plants competitive with conventional fossil-fuel generation. These incentives are designed to help mitigate the financial risk associated with large, capital-intensive electric-sector investments:

> "Nuclear power would be a competitive technology for a few new power plants, however, if those plants receive the maximum benefits that could be provided under EPAct. Most of the reductions would come from the production tax credit and loan guarantees."

Recent Cost Estimates for Other Baseload Generating Technologies

Electric companies are considering several generating technologies to meet their need for baseload power. In addition to nuclear, many utilities are seeking approval to build supercritical pulverized coal (SCPC) or IGCC plants to meet future electricity demand. These technologies face many of the same cost challenges and uncertainties as nuclear.

American Electric Power (AEP). Appalachian Power, a subsidiary of American Electric Power, received approval from the West Virginia PSC in March 2008 to build its 629 MWe Mountaineer IGCC plant in Mason County, West Virginia. In its initial filing for a Certificate of Public Convenience and Necessity (filed January 2006), Appalachian Power included a White Paper[12] that estimated the total cost for an IGCC plant at $1,550/kWe (year spent dollars), based on studies done by the Electric Power Research Institute (EPRI). This plant cost resulted in a levelized busbar cost of $56.2/MWh. IGCC with CCS was estimated at $2,150/kWe, resulting in a levelized cost of $79.4/MWh.

In subsequent testimony to the West Virginia PSC in June 2007, Appalachian Power revised its capital cost estimate based on the completion of the Front End Engineering and Design (FEED). The reasons for the cost increase were the completion of detailed design work by the EPC contractor, and escalation of materials and labor costs:

> "During [the FEED] phase, GE/Bechtel performed more detailed engineering and design of the AEP-specific plant. This included defining and selecting specific equipment to be utilized in the plant. This allowed GE/Bechtel to obtain vendor pricing on this equipment and to develop the quantities of bulk commodities such as piping, cable and conduit, concrete and steel for the ultimate installation. All of this led to the development of a November, 2006 cost estimate and a definitive schedule for the AEP-specific plant."

Appalachian Power now estimates capital costs for the Mountaineer facility at $2.23 billion (year spent dollars) or approximately $3,700/kWe, not including AFUDC. The new estimate includes $250 million of escalation and contingency to account for uncertainty in commodities and labor costs:

[12] American Electric Power Service Corporation's "Integrated Gasification Combined Cycle Technology" (2005).

> "The estimated direct cost of the base plant (baseline cost estimate) with transmission interconnection is $2.16 billion, based on November, 2006 pricing, prior to the addition of Company overheads. It should be understood that this is an estimate.
>
> The market has been extremely volatile in recent years, making it impossible to get reasonable pricing, materials costs and labor rates in advance … It is common engineering practice to include in projects a dollar value for unforeseen escalation and contingency. In the case of this project, the Company has built-in approximately $250 million of escalation and contingency."

Appalachian Power's June 2007 testimony also included analysis of the first year cost of electricity from an IGCC plant. Without CCS, the estimated cost of electricity ranged from $78-84/MWh (2006 dollars), depending on the sulfur content and associated heat value of the fuel. With CCS, the estimated cost ranged from $103-110/MWh.

However, these costs were still subject to revision. Appalachian Power notes in its testimony that due to the instability of certain commodity costs, the prices reflected in the total project cost will likely change following the issuance of a Notice to Proceed (NTP) with construction:

> "A significant company concern with respect to the proposed IGCC facility is the rapidly escalating costs for commodities used in large construction projects … In such a situation, no contractor is willing to assume this risk for a multi-year project. Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher. To deal with this volatility, GE/Bechtel will, following the issuance of [Appalachian Power's] NTP, adjust its prices for equipment, materials and labor on various cost categories, to reflect updated pricing values and vendor quotes."

In July 2008, the West Virginia PSC rescinded the certificate of need for the Mountaineer Plant citing a failure of the project to be approved by the Virginia State Corporation Commission which was a condition precedent for the project to move forward.

Duke Energy Corp. and Florida Municipal Power Agency (FMPA) et al. In February 2007, the North Carolina Utilities Commission approved a Certificate of Public Convenience and Necessity for Duke Energy Carolinas to build a new 800 MWe SCPC unit at its Cliffside site. In its filing, Duke estimates the capital cost of the project will be $1.8 billion (around $2,250/kWe), with an additional $550-600 million for AFUDC. The details behind the capital costs for the project are "proprietary and confidential."

In September 2006, a similar project was proposed by a consortium of Florida utilities, including the FMPA, for a 765 MWe SCPC in Taylor County Florida. Total installed cost for the project was estimated at $1.7 billion in 2012 dollars (around $2,200/kWe), including escalation of 2.5 percent and $135 million of AFUDC, calculated at a rate of 5.0 percent. In July 2007 the consortium voluntarily withdrew its petition for need determination due to concerns about climate chance and the potential cost of carbon dioxide emissions.

Putting Cost Estimates in Perspective

Although nuclear project costs are undeniably large, total project cost does not measure a project's economic viability. The relevant metric is the cost of the electricity produced by the nuclear project relative to alternative sources of electricity and relative to the market price of electricity at the time the nuclear plant comes into service. As illustrated by the detailed financial modeling cited above, new nuclear power plants can be competitive, even with total project costs exceeding $6,000/kWe, including EPC and owners' costs and financing.

Although nuclear project costs are undeniably large, total project cost does not measure a project's economic viability. The relevant metric is the cost of the electricity produced by the nuclear project relative to alternative sources of electricity and relative to the market price of electricity at the time the nuclear plant comes into service.

These findings are confirmed by results from a Nuclear Energy Institute (NEI) financial model [13] (see Table 1, next page). NEI's modeling shows that a merchant nuclear plant with an 80 percent debt/20 percent equity capital structure, supported by a federal loan guarantee, will produce electricity in the range of $64/MWh to $76/MWh. (The range reflects EPC costs from $3,500/kWe to $4,500/kWe) A high-cost ($4,500/kWe EPC cost) nuclear plant producing electricity at $76/MWh is competitive with a gas-fired combined-cycle plant burning $6-8/mmBtu gas or an SCPC plant.

Similar results are found using the same capital cost range for a regulated plant. Assuming a 50 percent debt/50 percent equity capital structure typical of a regulated electric company, and assuming the company is permitted to recover the cost of capital during construction (CWIP), NEI's financial model shows the levelized cost of electricity from the plant ranges from $74/MWh to $88/MWh – competitive with a gas-fired combined cycle plant burning gas at $8-10/mmBtu or an IGCC plant (without carbon capture and sequestration).

The results above do not assume any restrictions on carbon dioxide emissions. If a carbon price of $30/ton is incorporated, nuclear power becomes even more competitive. Generation from natural gas increases by around $13/MWh, while the cost of electricity from IGCC and SCPC increases by roughly $25/MWh.

NEI's modeling shows that, in the absence of a significant price for carbon, loan guarantees and supportive state policies (such as CWIP) are essential for merchant and regulated nuclear plants, respectively. Without this federal and state government support, it is difficult to see how new nuclear plants can be financed and constructed competitively. With this support as a transition to a carbon-constrained world, the next nuclear plants should be competitive and economically viable.

[13] The NEI Financial Model is a detailed financial pro-forma model used to estimate total project, first year and levelized busbar costs for new generating capacity built in either utility-regulated rate base or private sector project finance environments. The model was constructed and tested by NEI staff in consultation with financial, utility, and other industry experts.

Table 1. Cost of Electricity from Various Generating Technologies (Nuclear Energy Institute Financial Model)

Technology	Nuclear		SCPC	IGCC		Gas Combined Cycle		
Project Structure	PF LG 80/20	RB CWIP 50/50	RB CWIP 50/50	RB CWIP 50/50	PF LG 80/20	PF 50/50	PF 50/50	PF 50/50
EPC Cost ($/kWe)	$3,500 - 4,500		$2,250	$3,700		$1,000		
Total Cost ($/kWe)	$5,071 -6,378	$4,351 -5,473	$2,424	$4,164	$4,855	$1,195	$1,206	$1,218
Fuel Cost (nuclear - $/MWh) (coal/gas - $/mmBtu)	$7.50		$1.50	$1.50		$6.00	$8.00	$10.00
Capacity (MWe)	1,400		800	600		400		
First Year Busbar (2007 $/MWh)	**$64.4 - 75.8**	**$96.9 -118.8**	**$70.6**	**$112.3**	**$71.8**	**$70.4**	**$83.9**	**$98.4**
Levelized Busbar (2007 $/MWh)	—	$73.60 -87.70	$55.2	$83.60	—	—	—	—
Impact of $30/Ton C02 Price (2007 $/MWh)	—	—	+ $25.00	+ $25.0		+ $13.0		

Abbreviations: PF=project finance; LG=loan guarantee; RB=rate base; CWIP=construction work in progress.

Notes: The nuclear cases assume 48-month construction, 6-month start-up; owner's cost of $286/kWe and 10% contingency; 6.5% interest rate on commercial debt for unregulated entities, 6.0% interest rate on commercial debt for regulated entities, 4.5% interest rate on government-guaranteed debt, 15% return on equity; 5% loan guarantee cost in 80/20 loan guarantee case; 90% capacity factor; O&M cost of $9.50/MWh and fuel cost of $7.50/MWh. The capital cost estimates for supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) are from recent regulatory filings for projects.