COSTS OF CURRENT AND PLANNED NUCLEAR POWER PLANTS IN TEXAS

A Consumer Perspective

A Report Prepared for Public Citizen, Texas Office
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PREFACE

With the nuclear power industry pressing for a new wave of nuclear construction, the nuclear projects proposed in Texas will be unlike those proposed by regulated electric utilities in other states in one important way -- they are proposed by competitive power generators in a deregulated Texas power market (ERCOT). This report addresses the following questions about those nuclear generation proposals in ERCOT:

(1) What is the cost impact of the currently operating nuclear plants on consumers in the ERCOT market?

(2) What is the history of nuclear power costs and schedules in Texas, and what can that tell us about the likely costs of new nuclear plants?

(3) Are new nuclear power plants likely to be viable in the deregulated ERCOT market?

(4) Given that the power generators are not provided regulated rate recovery of new nuclear unit costs, why should consumers be concerned?

About the Author

Clarence Johnson has over 25 years of experience in the electric utility regulatory process. He was Director of Regulatory Analysis for the Texas Office of Public Utility Counsel until June 2008, when he left to engage in consulting. Mr. Johnson was chairman of the National Association of State Utility Consumer Advocate's economic and finance committee for more than 10 years. He has presented expert testimony in nearly 100 regulatory proceedings. He has been involved in prudence investigation proceedings for every nuclear power plant constructed by a Texas utility. Mr. Johnson has presented testimony on a wide range of issues, including generation capacity expansion, avoided costs, and the transition from regulation to competition.

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EXECUTIVE SUMMARY

This report includes the following conclusions.

- The low operating costs of Texas' current nuclear power plants do not tell the complete story of their impact on customers in the ERCOT market. The low operating costs benefit the owners of the generation, rather than consumers. Moreover, consumers in ERCOT continue to pay off at least $3.4 billion for nuclear assets (net of revenues) through transition charges, as well as approximately $45 million in annual payments for nuclear decommissioning.

- Cost overruns were extensive in the U.S. nuclear power industry, and the cost / scheduling performance of Texas nuclear power projects were among the worst in the industry. The two Texas nuclear plants were 61% - 140% more costly and took 2-5 years longer to build than the average nuclear power plant.

- Quality assurance / quality control (QA/QC) breakdowns were pervasive among the most costly nuclear power plants, and the nuclear projects in Texas had particularly significant QA/QC problems. Regulatory streamlining has not altered the requirement that nuclear construction projects comply with rigorous QA/QC. Standardized design is unlikely to eliminate QA/QC risks, and certain factors related to the new nuclear plant proposals in Texas could impose greater risks of QA/QC cost / schedule impacts.

- A reasonable estimate of the real ($2008) cost of building a new two unit nuclear power project is $5,922 - $6,160 per kW. If construction began in 2012, and ordinary inflation is 2%, this implies a nominal cost of $7,000 - $8,130 per kW, or $20 - $22 billion (2700 MW) [$25 - $26 billion (3200 MW)].

- On a real ($2008) levelized busbar basis, a new nuclear project will be 50% more costly over its life than the primary conventional alternative, combined cycle gas generation. Building a new nuclear project in ERCOT is not likely to produce a positive internal rate of return. A portfolio of energy efficiency, alternative resources, and conventional generation is likely to be more cost-effective.

- Given the high costs of the nuclear option, cost overruns are likely to result in pleas for additional public subsidies. The two generation companies proposing to expand their existing nuclear projects in Texas are dominant in their relevant geographic markets and in the baseload generation product market. The expanded nuclear plants will increase the potential for market power within ERCOT, and the likelihood of financial losses resulting from construction of the plants will increase the temptation for owners of the plants to raise prices above competitive levels.

I. COST IMPACT OF CURRENT TEXAS NUCLEAR PLANTS IN THE DEREGULATED ERCOT MARKET

The two current nuclear power plants operating in Texas are Comanche Peak 1 and 2 (CP) and South Texas Nuclear Project 1 and 2 (STP). The ERCOT power region market was deregulated in 2001. Frequently observers of the ERCOT energy market will point to low operating costs associated with STP and CP in order to emphasize the cost-effectiveness of the plants.

However, referencing operating or running costs of nuclear plants is a very misleading description of the cost impacts of STP and CP on the ERCOT market. The principal economic disadvantage of nuclear power plants are the very high capital investment costs. Looking only at the running cost of nuclear power plants, and ignoring the high capital investment, provides only a narrow glimpse of the full costs incurred for nuclear units. Running costs certainly are useful in evaluating prospective decisions related to the units, since capital investment is a sunk cost. However, relying on "cheap running costs" to justify the cost impacts of the plants is delusory. Ratepayers of regulated investor-owned utilities had already paid off about $5 billion of these nuclear investments in Texas prior to the initiation of deregulation.

In addition, the operating costs of CP and STP have limited relevance to the costs paid by ratepayers in areas of ERCOT subject to competition.[1] First, the "low operating costs" of STP and CP provide more benefit to the owners of generation than consumers. Power prices paid by customers in the ERCOT market are largely driven by the cost of gas – even if nuclear fission is the source of the power. Second, customers in competitive regions on the Gulf Coast continue to pay for nuclear power assets through non-bypassable charges. "Non-bypassable" means that the charges cannot be avoided by customers in the competitive market, even if they purchase power from a source other than nuclear generation.

[1] The discussion in this section does not apply to the co-owners', Cities of Austin and San Antonio, which are not subject to competition, and provide power to their residents on a cost of service basis.

A. Pricing of Nuclear Generation in the Competitive Market

The Texas Comptroller recently reported:[2]

> *Low Cost Energy*
> *STP has the lowest production cost reported by nuclear power plants nationwide, at 1.356 cents per kWh in 2006.*

Spot prices in the ERCOT market are based upon the marginal (e.g., highest price bid) generating units for each hour of the year. Because natural gas generation tends to be the marginal unit for most hours of the year, ERCOT prices tend to track natural gas pricing. Nuclear plant operators, in theory, are price-takers, meaning that nuclear generation cost never sets the price in any hour; nuclear generation operates in virtually all hours and accepts the prevailing ERCOT market price of energy.

In 2007-2008, the weighted daily market price in the ERCOT balancing energy market was $56-$83 per MWh.[3] The nuclear operating costs cited by the Texas Comptroller, above, equates to $13.56 per MWh. Although Texas consumers would find $13 per MWh an attractive price to pay for power, the fact is that consumers will actually pay four to six times that amount for nuclear generation in the ERCOT market, based upon recent market conditions.

Nuclear plant owners may sell some of the nuclear power output at somewhat lower priced forward contracts. However, those contract prices reflect expectations regarding ERCOT market prices, which means that the nuclear power prices for hedged positions are still a multiple several times greater than the underlying nuclear operating expense.[4]

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2 *Fiscal Notes*, Special Energy Issue 2008, Texas Comptroller of Public Accounts.

3 PUC Scope of Competition Report, 2009.

4 Public filings by NRG, the owner of STP, suggests that forward prices are in the $45-$55 per MWh range.

B. Nuclear Power "Legacy Costs" Continue in the Market

The so-called legacy costs associated with Texas nuclear power plants continue to be paid by consumers in the form of non-bypassable charges (NBC). In accordance with Texas' deregulation law, the NBC is collected from all customers in the service area of the utility which originally built the nuclear plant. The NBC is part of the transmission/distribution utility's rates. The NBC collects regulatory assets, stranded costs, and nuclear decommissioning expense.

1. Recovery of South Texas Project Investment Costs from Ratepayers

In 2002, Reliant Energy and CPL[5] implemented NBCs to recover regulatory assets, which is an accounting term for monetary sums which prior PUC orders "promised" to the former regulated integrated utility. Regulatory assets are paper assets, and therefore, have no current productive value. A large part of the regulatory asset balance involves nuclear power plant rate increases which were deferred by the PUC. In addition, the stranded cost true-up cases in 2004 and 2005 for CenterPoint Electric (CNP) and AEP-Texas Central Company (TCC) determined the amount of stranded costs to be recovered through NBCs. The deregulation law's calculation of stranded costs is based upon the former integrated utilities' balance of net generation plant and equipment on December 31, 2001. The stranded costs and regulatory assets are recovered through securitized transition charges, which means that the cost recovery has been guaranteed by state law.

South Texas Project plant and regulatory asset costs recovered from ratepayers in the Houston and South Texas area are shown on the following table:[6]

[5] Reliant and CPL are the corporate names for the transmission/distribution utilities which would later be called CenterPoint Electric and AEP-Texas Central Company.

[6] Data from true-up and securitization cases, Texas PUC Docket Nos. 29526, 31056, 21528, and 21665.

Continued Recovery of STP
Legacy Costs from Ratepayers
(000's)

STP Net Plant and Equipment

TCC	$1,509,957
CNP	$1,570,321
Total	$3,080,278

STP Regulatory Assets

TCC	$ 876,301
CNP	$ 576,680
Total Regulatory Assets	$1,452,981

Total Net Plant Plus Regulatory Assets

TCC	$2,386,258
CNP	$2,147,001
Total	$4,533,259

Costs Per STP Installed Capacity

Recovery: Net Plant	$2,622/kW
Recovery: Net Plant & Reg. Assets	$3,858/kW

2. STP Sales Transactions: Follow the Money

The Texas restructuring law set out provisions for crediting ratepayers with the proceeds from selling the STP generating plant to new owners. This process is supposed to occur during the stranded cost true-up proceeding.

After deregulation, CNP placed generation plant assets in an affiliate, Texas Genco. In 2004, an investment group[7] bought Texas Genco for $3.62 billion. Twenty-four percent of the transaction's payment was for STP.[8] However, the Texas PUC chose

[7] Texas Pacific Group, Kohlberg, Kravis, Roberts (KKR), Blackstone Group, Hellman & Friedman.

[8] The transaction paid CNP, which owned 81% of Texas Genco, $700 million for STP.

to credit only 94% of the sale proceeds to ratepayers, which provided a $227 million windfall to CNP.[9]

Less than a year later, the investment group sold the Texas Genco generation assets to NRG for $6.2 billion.[10] None of the sales proceeds are used to offset stranded costs borne by ratepayers. The New York Times reported at the time:

> *Texas Genco might lack the flash and fame of Enron, but its low profile owners have managed to accomplish something rare in this swaggering city: a deal so ambitious in its scale that it has caused jaws to drop in Houston's energy circles while angering and perplexing people who are feeling the sting of surging electricity prices.*[11]

As noted in the *Times*, the initial investment group paid only $500 million cash to CNP in the previous leveraged transaction, and stood to make a $5 billion profit by "flipping" the generation assets to NRG. Several of the principals in the investment group would later engineer a $30 billion leveraged buyout – the largest such corporate buyout in history – of TXU Corporation, the owner of Comanche Peak.

TCC received only one bid for selling its share of STP – from Cameco, a uranium supplier. Texas Genco and San Antonio exercised rights of first refusal and paid $314 million for 630 MW of STP, which was credited to ratepayers.

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9 $3.62 billion - $3.394 billion = $227 million. *See,* PUC Order, Docket No. 29526, Schedule I.

10 The sales price was publicly reported as a range of values at the time. The NRG 2007 SEC Form 10-K reports the price at $6.1 billion.

11 New York Times, November 23, 2005, "The Deal That Even Awed Them In Houston," by Simon Romero.

Summaries of the sales proceeds pertaining to STP are shown below.

STP Asset Sale
(000's)[12]

Total Sales Revenues for STP Credited to Ratepayers	$1,124,815
Per kW	*$957/kW*
Total STP Plant & Regulatory Assets, Net of Sales Proceeds, Paid by Ratepayers	$3,408,444
Per kW	*$2,900/kW*
NRG Purchase of STP (not credited to ratepayers)	$1,718,680
Per kW	*$1,462/kW*

An interesting observation from this table is that, together, both NRG and ratepayers are paying off over $5 billion for 44% of STP.[13] Ratepayers are paying costs through securitized NBCs, and NRG will try to recoup its purchase cost through profit from the sale of STP energy into the ERCOT market. Combined, TDU ratepayers and NRG are paying a staggering $4,363/kW for STP investment.

3. Luminant (TXU) and Comanche Peak

Ratepayers in North Texas are somewhat more fortunate because Comanche Peak plant costs are not directly reflected in non-bypassable charges. TXU reached a settlement with the PUC Staff and other parties in the regulatory process, whereby TXU agreed to forego stranded cost recovery. Furthermore, TXU did not utilize deferred accounting for CP, and therefore, did not have the magnitude of nuclear regulatory assets on its books which CNP and TCC did.

[12] NRG total transaction price prorated to nuclear assets based on ratio of STP plant cost to total Texas Genco plant cost, as reported on NRG's SEC 2007 Form 10-K.

[13] Remaining shares of STP are owned by the City of Austin and City of San Antonio.

However, this is not to say that Comanche Peak did not have an indirect effect on the level of NBCs paid by Oncor[14] customers. According to the PUC, TXU gave up its right to recover up to $1.1 billion in Comanche Peak court remand costs, plus $3.6 billion in stranded costs, most of which are related to CP.[15]

Obviously, TXU would not forego recovery of such significant sums related to CP, unless it received very significant benefits from the settlement. Given the nature of this settlement, we cannot fully identify or quantify the value which TXU received in return. However, TXU securitized $1.3 billion in regulatory assets as a result of this settlement, which may have been as much as $1 billion higher than the Commission otherwise would have found to be eligible for NBC recovery.[16]

Furthermore, by entering into this settlement, TXU was not forced to sell or divest its generating units.[17] We cannot quantify the value to TXU of this benefit. But, clearly TXU is strongly dominant in its generation market share, and it is possible that the outcome of the settlement may have affected market power conditions in the ERCOT market.

C. Decommissioning Expense

Nuclear plants have extraordinary requirements for decommissioning at the time the units are retired. Because major components of the facility are radioactive, dismantling the facility is likely to be very expensive. The NRC requires nuclear plant licensees to maintain sinking funds which are financially structured to cover the expected cost of decommissioning. Since the expected cost of decommissioning is uncertain, and

14 Oncor is the current transmission/distribution utility affiliated with Luminant and the TXU businesses.

15 Order, PUC Docket No. 25320.

16 *See,* Order, PUC Docket No. 21527, allowing TXU to securitize $363 million in regulatory assets. The order was remanded by the Texas Supreme Court for further consideration, and was eventually supplanted by the $1.3 billion securitization amount.

17 Generation asset sales normally are part of the stranded cost true-up process. By foregoing stranded cost, TXU avoided this process.

can increase as new information becomes available, payments into decommissioning trust funds may increase over time.

The Texas deregulation law provides that the nuclear decommissioning funds for CP and STP remain regulated. Oncor, TCC, and CenterPoint collect non-bypassable decommissioning charges from ratepayers. Currently, ratepayers of those three T&D utilities pay approximately $45 million annually ($13.50/kW/year). As with all NBCs, ratepayers must pay this expense even if they choose to purchase power from generators other than Luminant and NRG.

In essence, this is a ratepayer subsidy for NRG and Luminant since neither company is responsible for collecting decommissioning expenses from the sale of energy from the current CP and STP units. If the decommissioning funds are insufficient at the time the nuclear units are retired, ratepayers will continue to be responsible for making up the difference.

II. HISTORY OF COST AND SCHEDULE INCREASES

> *"Those who cannot remember the past are condemned to repeat it."*
>
> --George Santayana 1905

Is nuclear power preparing for a rebirth in the United States? Is Texas "ground zero" for a rebirth of nuclear power? NRG and Luminant have applied for two additional nuclear power units each at the existing South Texas Project (STP) and Comanche Peak (CP) sites. Exelon has proposed another two unit nuclear project in Victoria, Texas. Although those plans appear consistent with the concept of a resurgent nuclear industry, the proposals also appear to be based upon extremely optimistic assumptions regarding construction costs.

The cost estimates supporting the power plant proposals in Texas are not based upon actual realized cost results for building nuclear power plants in the United States. This makes the cost estimates very difficult to verify or test, particularly since the power generation companies in Texas are deregulated and are under no requirement to provide any detailed support for their estimates.

NRG's current cost estimate for STP 3 and 4 is $8 billion, or $2900/kW.[18] Luminant only has provided a range of $2,500-$6,000/kW.[19] Since Luminant's range implies a construction cost of $8.5 billion to $20 billion, the cost span is so broad that it may not be very meaningful. Neither company indicates whether these cost estimates include capitalized interest charges or future inflation.

The realism of new nuclear power plant cost assumptions cannot be tested without reviewing the history of nuclear power plant construction costs in the United States. The cost history of the existing CP 1 and 2 and STP 1 and 2 units, as well as the overall industry experience in the United States, provide a tough, but healthy, dose of reality for the evaluation of the nuclear power option in Texas.

A. Cost Overruns at STP and CP

Even by the nuclear industry's standards, STP and CP are extraordinarily expensive power plants. Comanche Peak holds the distinction of being the most expensive completed nuclear power project built in the United States. STP and Comanche Peak were completed in 1989 and 1991.

The total costs of each project include capitalized financing charges (called "Allowance for Funds Used During Construction" or "AFUDC") but exclude regulatory asset costs associated with initial rate recovery.[20] CP's total cost was at least $12.18 billion. STP's total cost was $8.25 billion. These total costs are substantially higher than the average total costs for multi-unit nuclear power plants built during the 1980s:

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[18] *Nuclear Engineering International*, "The American Way," June 11, 2008.

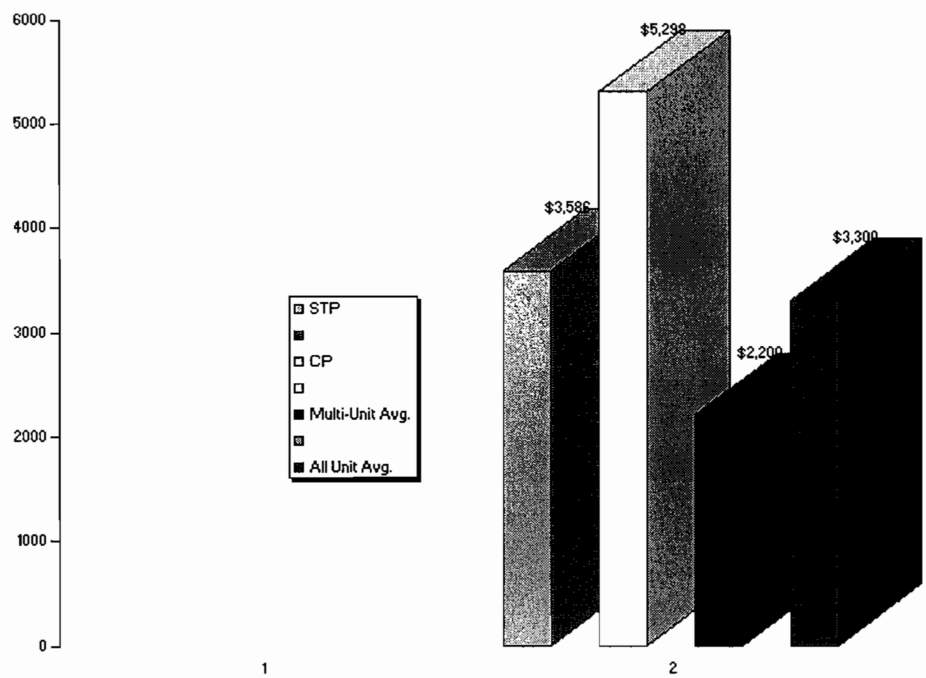
[19] "Update 1 – Luminant Seeks New Reactor," Reuters, Sept. 19, 2008, 3:08 p.m. EDT.

[20] An "actual" STP cost including financing charges is not available, because of differences in the accounting practices and rate recovery methods applicable to public financing (the co-owners, City of Austin and City of San Antonio) and investor-owned utilities. The estimated total cost used in this report is based upon extrapolating CPL's AFUDC costs to 100% of STP's direct costs. CP costs are based on TU Electric's 1995 FERC Form 1.

Total Project Cost
(including AFUDC)

STP 1 and 2	$ 8.25 billion
CP 1 and 2	$12.18 billion
Average Multi-Unit[21]	$ 5.09 billion
STP Percent Above Average	*61%*
CP Percent Above Average	*140%*

The graph below shows STP and CP installed cost per kW compared to nuclear plants completed after 1979.



A nuclear power plant definitive cost estimate (sometimes called "initial baseline estimate") is the detailed engineering estimate for building the project before construction begins. CP and STP definitive cost estimates (DCE) were completed in May, 1975 and

[21] Average post-1979 multi-unit cost is based upon Initial Testimony of Charles Komanoff, Docket No. 6668, Texas PUC.

June, 1976, respectively. Because the DCEs did not include AFUDC, the estimates are not comparable to the final plant costs shown above.

Cost Overruns Above DCE
(excluding AFUDC)

STP	
1976 DCE	$1.238 billion
Actual Cost	$5.8 billion
Percent Overrun	368%
Comanche Peak	
1975 DCE	$978 million
Actual Cost	$7.8 billion
Percent Overrun	690%

Based upon Energy Information Administration (EIA) data, for nuclear plants started between 1966 and 1977, the average overrun in excess of the initial cost estimate was 203%. This demonstrates that the nuclear industry overall suffered severe cost overruns, but that STP and CP incurred much higher overruns than the industry average.

A portion of the cost overruns can be attributed to inflation rates higher than expected at the time the cost estimates were prepared. The national economy experienced high rates of inflation in the late 1970s and early 1980s. The inflation rates applicable to the specific materials used in nuclear plants tended to be higher than the overall inflation rate. However, part of the cost overruns represent "real cost escalation," *i.e.,* cost increases beyond the increase in input prices. Real cost escalation represents higher than expected quantities of materials and labor, worse than expected productivity for installing materials and excessive amounts of rework.

The analysis shown below uses the EIA cost overrun data,[22] by construction start date, and estimates the portions attributable to unanticipated inflation and real cost escalation. The unanticipated inflation is based upon the difference between the nuclear

[22] "An Analysis of Nuclear Power Plant Costs," 1986, Energy Information Administration.

industry inflation rates in the year construction started and the average nuclear price inflation rate over the succeeding nine years.[23] The remaining cost overrun amount is used to estimate real cost escalation.

Cost Overrun Data
By Construction Start Date

Year	Cost Overrun %	Real Cost Escalation As % of Overrun	Estimated Real Esc. Annual Rate
66-67	109%	20%	2.3%
68-69	194%	40%	6.6%
70-71	248%	58%	11.2%
72-73	281%	46%	8.2%
74-75	165%	84%	17.7%
76-77	203%	65%	9.7%
Average	203%	52%	9.3%

The derived real escalation rate, above, can be checked against the real overnight cost per kW resulting from nuclear plants started in each of those two-year periods.[24]

Average Completed Cost/kW
by Year of Construction Start

Year Started	Cost / kW	Implied Annual[25] Escalation Rate
66-67	$1279	
68-69	$2180	35.2%
70-71	$2889	16.2%
72-73	$3882	17.2%
74-75	$4817	12.0%
76-77	$4377	-4.5%
Average Real Escalation Rate Per Year		**15.2%**

23 Because the price index for nuclear plant costs is used to measure inflation in this and subsequent real cost calculations in this section, nuclear-specific price increases due to material/labor shortages are reflected as "inflation." Some analyses would classify nuclear-related price increases above economy-wide inflation as a real increase.

24 Data source: "Nuclear Power's Role in Generating Electricity," Table 2-1, Congressional Budget Office Study, May 2008.

25 Escalation rates for two year intervals divided by 2 to derive annual rates.

Estimating annual real cost escalation by comparing real costs in the construction start sequence, above, produces a higher estimated real cost escalation rate than the cost overrun analysis in the previous table. In order to check whether the use of construction start dates distorts the estimate of real cost escalation, real costs for post-1979 nuclear power projects are evaluated by year of plant commercial operation in order to perform a similar real cost analysis.[26]

Real Cost Escalation By Year of Completion

Year	No. of Plants	Cost / kW	Implied Annual Escalation Rate
81-83	4	$1503	
84-85	10	$2055	18.3%
86-87	9	$3367	31.9%
88-89	4	$3171	-2.9%
Average Real Escalation Per Year			15.8%

The implied real escalation rate by year of plant completion is similar to the rate calculated on the basis of construction start date.

Based on the analyses presented in this section, the real (inflation adjusted) costs of building nuclear plants increased at an annual rate of approximately 10% - 16% over the construction duration of the plants.

B. Construction Schedules

Nuclear power plant costs are very sensitive to the schedule duration, as measured by construction start date to commercial operation date. Financing costs incurred during construction are added to plants' capital costs as AFUDC (or "interest during construction" for unregulated generation companies). AFUDC increases directly with construction duration, and can grow to massive proportions over a 10-year schedule. Lengthier schedules also expose the nuclear project to more cost escalation, both in terms

[26] Real cost data ($1987) from Komanoff Energy Associates data base and workpapers filed in Texas PUC Docket No. 6668. STP and Comanche Peak costs are updated for this analysis.

of price/wage inflation and real cost growth. Real cost escalation (*i.e.,* growth in quantities of labor and material consumed) tends to accompany extended schedules for several reasons: a causal relationship between real cost drivers--such as poor material installation rates or stop work orders--and schedule extensions; inefficiencies caused by "work arounds" and improper sequencing of activities when the critical path for the schedule is delayed; and lengthened exposure to external risks, such as regulatory events, economic disruptions, procurement delays, and labor or material shortages.

The lengthy construction schedule for a nuclear project also has adverse consequences for a generation company's resource planning decision. A schedule delay may cause a utility to purchase expensive purchase power contracts, or lead to an in-service date which is not synchronized with demand growth. The lengthy construction schedule will be particularly problematic in a competitive market, like ERCOT. Financial and business plan decisions of a merchant generator are dependent upon the ability to predict future market conditions (such as a shortage or excess of generation capacity). Forecasting market conditions over the 2-3 year duration for building gas capacity is more manageable than the 10-year duration of a nuclear plant.

The initial construction schedules associated with the STP and CP are compared to the actual construction durations below.

Construction Duration
Construction Permit to Commercial Operation
(Unit 1 of Each Project)

STP	**Years**	**Months**
Planned	5.0	60
Actual	11.67	140
Slippage	6.7	80
Comanche Peak	**Years**	**Months**
Planned	5.5	66
Actual	15.1	181
Slippage	9.6	115

As indicated above, the slippage in CP's schedule was almost 10 years; the delay, alone, in the CP schedule was equivalent to the full construction duration of many other nuclear plants.

The schedule performance of CP and STP were among the worst in the nuclear industry. The interval, first concrete pour to fuel load, is frequently used to compare nuclear plant schedule performance. The first concrete to fuel load duration for the initial units of STP and CP are compared to average nuclear industry data below.

First Concrete to Fuel Load
Construction Duration[27]

	Years	Months
STP 1	11.3	136
CP 1	14.6	176
Multi-Unit Average	9.1	109
Nuclear Plant Average	8.75	105
STP Excess Over Average	*2.3*	*33*
CP Excess Over Average	*5.75*	*69*

C. Causes of Poor Performance

1. STP and CP History

Comanche Peak and STP had some common historical elements. Both HL&P and TU were nuclear applicants without prior nuclear construction experience. Brown & Root[28] was selected as the construction contractor on both projects. Both projects experienced extensive work stoppages due to quality assurance issues.

Quality assurance and quality control (QA/QC) breakdowns were exacerbating causes of cost escalation at most "high cost" nuclear projects like STP and CP. QA/QC requirements are governed by 10 CFR 50, Appendix B, which is comprised of 18 broad

[27] Data from Testimony of MHB Technical Associates, PUC Docket No. 6668 and Testimony of David Schlissel, Texas PUC Docket No. 9300.

[28] Brown & Root (B&R) later became part of Halliburton. B&R was also selected as the Architect-Engineer on STP.

criteria for assuring that systems and processes are in place to assure the safety of the design and construction of the nuclear plant. More prescriptive standards have been developed in engineering codes to achieve the criteria. Rigorous QA/QC requirements are a major factor distinguishing the complexity of building a nuclear plant from other projects. QA/QC is the oversight function for verifying and inspecting engineering drawings and calculations, designs, materials, construction practices, and procured components for compliance with safety requirements. The QA/QC process also applies to fabrication of safety-related components in the manufacturing facilities of vendors.

STP showed signs of construction QA/QC problems in 1977 and 1978, which manifested in conflict between QC inspectors and construction personnel. In 1979-1980, the NRC conducted major investigations of 31 allegations of bad construction practices, workmanship, and falsification of records. The investigation substantiated widespread intimidation and harassment of QC inspectors. In 1980, the NRC issued a show cause order, and the licensee responded by voluntarily shutting down safety-related construction and vowing to re-vamp QA/QC. The licensee also commissioned an independent engineering report, which concluded that much of the project design work could not be verified. By the end of 1981, HL&P terminated Brown & Root. The process of hiring a new Architect-Engineer and Constructor, and establishing a credible baseline for re-starting construction, added another year to the two year hiatus. The STP owners sued Brown & Root, and litigation ended in a cash settlement of $650 million from Brown & Root.

The magnitude of problems at Comanche Peak was obscured until the late stages of construction. CP managers opted for an "after the fact" design verification process. In essence, TU Electric decided that the conformance of the as-built plant to the planned design would be demonstrated during the late stages of building the plant. This gave the appearance of a relatively smooth construction project during the early stages. Whether this process complied with QA/QC regulations is debatable, but CP's lack of QA success is not.

Skepticism regarding CP design verification grew stronger when "whistleblower" personnel contended that certain engineering calculations were unverifiable. As CP construction came to a "completion" in 1984, the NRC's Atomic Safety and Licensing Board rejected the licensee's efforts to rely upon "engineering judgment" to verify design. CP initially embarked on a statistical sampling program to verify design, but subsequently gave up that approach and began a lengthy program for 100% design verification. This process required, in some instances, removal of constructed portions of the plant, accompanied by extensive rework of the deficient components. These corrective actions caused commercial operation to be delayed until 1990.

In a public letter to an intervenor in the NRC licensing proceeding, TU Electric acknowledged its responsibility for the delays:[29]

> TU Electric also recognizes its own shortcomings in assuring the NRC that they fulfilled NRC Regulations. We acknowledge that nuclear expertise did not exist to meet those demands and that its nuclear management did not have full sensitivity to the regulatory environment.

At the request of Congress, the NRC developed a major report in 1984 on QA/QC breakdowns at U.S. nuclear power plants, called the "Ford Amendment Study."[30] STP was one of the case studies analyzed in the NRC report. Although CP's design verification issues became more well-recognized subsequent to the study, the conclusions of the study could well apply to CP.

The case study of STP stated:[31]

> The primary root cause for the construction difficulties was the inexperience of the project team. While the licensee had extensive experience in constructing and operating fossil fuel-fired plants, it had not been involved with constructing a nuclear plant. It apparently failed to appreciate the difference

[29] Letter from TU Vice President Council to Juanita Ellis, June 28, 1988.

[30] NUREG 1055, "Improving Quality and the Assurance of Quality in the Design and Construction of Nuclear Power Plants," 1984. The Ford Amendment was enacted by Congress, and required the NRC to assess the causes of quality assurance problem.

[31] *Ibidem,* A-21 thru A-23.

> in scope and complexity between the two, as reflected in the management methods and procedures applied to the project by both itself and the prime contractor.
>
> The licensee's lack of nuclear experience was further aggravated by the lack of experience of key individuals involved withy the construction project. This project was the first nuclear project for the project manager, project engineering manager, and the quality assurance manager.
>
> * * * *
>
> While not adequately involved at higher levels of management, in some respects the licensee became too involved at lower levels. Licensee personnel found themselves directly in the approval chain for A-E/C design approvals and other documents. This had the effect of unduly restricting work flow. Everyone in the chain had veto authority, and everyone had to agree. Toward the end of the A-E/C's tenure, the licensee assumed nearly all of the contractor's responsibility in an intensive but vain effort to help the contractor's effectiveness.
>
> * * * *
>
> <u>There was an insufficient review by the NRC of the licensee's (and it's A-E/C) experience in nuclear plant construction, and an inadequate involvement in the inspection process in the early phases of construction.</u> A recurrent theme was that the NRC licensing process did not adequately address the ability and experience of the project management, nor was there adequate evaluation of whether the nuclear industry had over-extended itself at the time this plant was contracted.
> (emphasis in original)

The study developed overall conclusions regarding quality assurance in the nuclear industry:[32]

> The case studies were also useful in understanding what the principal causes of the quality-related problems were not, e.g., craftsmanship. The case studies found that while poor craftsmanship played a role in some of the major quality-related problems, it was an effect, not the cause, of the underlying problems. The principal underlying cause of poor

[32] *Ibidem,* 2-4; A-4 thru A-5.

> craftsmanship in constructing nuclear power plants, as well as the quality problem, was found to be poor utility and project management.
>
> * * * *
>
> The single most important factor in assuring quality in nuclear power plant construction is prior nuclear construction experience (*i.e.,* licensee experience in having constructed previous nuclear power plants, personnel who have learned how to construct them, experienced architect-engineers, experienced constructors, and experienced NRC inspectors).
>
> * * * *
>
> Safety by itself does not appear to be a sufficient motivation for ensuring good quality. For the most part, industry has been lagging the NRC with respect to assurance of quality. This is evidenced by the fact that industry does not appear to feel that greater attention to quality is needed. That situation is likely to change only when the utility industry focuses on an objective that is more meaningful to them--one that includes safety, perhaps reliability. Licensees seem to believe that their plants are (or will be) safer than the NRC credits them to be; thus, assurance of quality requirements often appear excessive to licensees.

2. Applicability to Future Projects

Optimism about future nuclear power project costs is based upon the "streamlining" of NRC licensing and regulatory requirements. However, as discussed above, the worst cost and schedule performances generally involved plants with QA/QC breakdowns, including the two nuclear projects built in Texas.

The Appendix B QA/QC requirements continue to apply to nuclear power plant construction projects. NRC "streamlining" does not eliminate the vulnerability of nuclear projects to QA/QC breakdowns. Indeed, after 20 years without nuclear construction in the U.S., the pool of qualified nuclear QA/QC personnel, as well as experienced nuclear construction management personnel, has dwindled considerably.

In theory, the NRC's certification of standardized designs could indirectly reduce QA/QC risks. However, several factors applicable to the proposed nuclear plants in Texas probably outweigh this theoretical benefit:

- The Ford Amendment report cites the licensee's experience in constructing a nuclear plant as the single most important determinant of QA/QC performance. NRG has no nuclear construction experience. The nuclear construction experience of Luminant is based on construction which occurred 20-30 years ago--and which produced sub-par cost performance.
- In order to "obtain" nuclear construction experience, NRG and Luminant have turned to Japanese nuclear design and engineering firms. Given the lack of U.S. experience with foreign nuclear contractors, coordination of project management may not be seamless. NRG has already encountered licensing delays because of competition-related impediments to coordinating two Japanese contractors, Hitachi and Toshiba, on the proposed new STP units.[33] Conflicts between the licensee and the prime contractors was a contributor to breakdowns at STP 1 and 2.
- The number of nuclear suppliers in the U.S. and the number of engineers with N-stamp certificates, has declined by approximately 80% over the past 20 years.
- Because of the declines, above, new nuclear projects are likely to rely heavily on foreign vendors and engineers. Up to 80%[34] of the materials used on U.S. nuclear projects will be supplied by foreign firms. This is unprecedented for the domestic nuclear industry, and will raise daunting issues for implementation of QA/QC. The NRC's QA/QC inspection process must be applied to the facilities of foreign vendors. The problems which have arisen as a result of the pharmaceutical industry's reliance upon foreign materials--and the inability to adequately inspect foreign manufacturing facilities--provides an analogous example. Already, even without the pressure of new construction demands, foreign

[33] Nuclear Engineering International, *ibidem*. (Because Toshiba and Hitachi compete in the nuclear steam supply business, issues have arisen regarding Toshiba's access to Hitachi trade secrets.)

[34] "Utilities Fret as Reactor Parts Suppliers Shrink," Rebecca Smith, Wall Street Journal, April 11, 2008.

> produced counterfeit parts have been purchased by nuclear operators.[35]

Finland's Olkiluoto nuclear plant, a "standardized" advanced reactor, shows that standardization does not provide an inoculation against QA/AC problems. The plant, which is many years behind schedule and over-budget, has recorded 2,200 quality deficiencies, including a hand forged containment steel liner with major design and welding defects which required extensive rework.[36] *Washington Monthly* quoted Jouni Silvennoinen, construction manager for the Finnish Utility:

> *...in his view, projects as large and complex as reactors simply don't lend themselves to cookie-cutter solutions. "The basic design can be planned in advance," he explained. "But you still have to do the detailed design. Where exactly is the rebar? How thick are the walls? Where is the pinning for pipes? Those details have to be tailored to the individual project, and it takes a tremendous amount of work."*

III. FUTURE CONSTRUCTION COSTS FOR STP AND CP

As stated previously, NRG's current cost estimate for STP 3 and 4 is $8 billion or $2,900/kW.[37] Although this estimate is too low (even in comparison to other U.S. utilities' recent estimates), the NRG cost estimates has grown by 60% over a two year period, much like the trend for conceptual cost estimates for nuclear power plants in the 1970s.[38] Luminant's stated ranges of $2,500-$6,000/kW for CP 3 and 4 spans a range which is unrealistically low--below NRG's estimated at low end--to a higher value which may be realistic. NRG has stated a construction schedule of four years for STP 3 and 4, which also appears to be unrealistic.[39] Such a schedule would be shorter than any other

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35 *Ibidem.*

36 "Bad Reactors: Rethinking Your Opposition to Nuclear Power, Rethink Again," Mariah Blake, *Washington Monthly*, Jan./Feb. 2009.

37 Whether this estimate includes interest during construction or is stated in real or nominal dollars is unknown.

38 The definitive cost estimates for nuclear power plants of that era often were more than double the earlier plant-specific conceptual cost estimates.

39 Whether NRG has subsequently extended its schedule projection is unknown.

large U.S. nuclear plant; St. Lucie 2, with the best schedule performance among plants completed in the 1980s, had a schedule approximately 56% longer than NRG's projection.

A. Estimating Future Capital Costs

The historical data reviewed in Section II can be used as a baseline for estimating future nuclear power capital costs. For purposes of this estimation, costs will be expressed in 2008 real dollars, net of inflation. Interest during construction will also be reflected in real terms, with an inflation adjusted interest rate. Because the future rate of ordinary inflation, as measured by the CPI or GNP implicit price deflator, is particular uncertain in the current state of the economy, the use of real costs avoids any speculation over future economy-wide inflation trends.

The real cost in 1987 dollars, for post-1979 nuclear projects is *$2,576/kW*, without AFUDC. This might compare favorably to the low end of Luminant's estimate or NRG's slightly higher estimate (if those estimates are expressed in real dollars). However, to accept this value as reasonable would ignore the fact that labor and material costs have risen substantially over the past 20 years.

In order to adjust for inflation, a weighted price escalator was developed based upon BLS data for construction materials and construction wages.[40] As a conservatism, a productivity offset based on BLS data was used to reduce the price escalator. Technological improvements have occurred which provide the potential to improve production per unit of labor or materials. This offset also recognizes the claims that new nuclear power plants will benefit from improved construction techniques.

Based upon the inflation measured above, net of productivity, real costs for 2008 are *$4,070/kW* without interest during construction. Based on industry experience, a schedule (first concrete pour to commercial operation) of 109 months was adopted, with

[40] This escalator is significantly lower than the results of power plant-specific materials indexes since 2000, which is another conservative element.

an accompanying assumption of commercial operation for both 1,350 MW units within 9.5 years.

Based upon average industry experience, real cost escalation (*i.e.,* cost increases in excess of ordinary inflation) is 10%-16% per year over the course of construction. This real escalation rate is reduced by a factor of 21% to exclude the effect of Three Mile Island disruptions.[41] [42]

Based on the schedule above, cash flows, real escalation, and real AFUDC (or interest during construction) are estimated. The following results are shown for real 2008 dollars, including interest.

	Real Costs ($08) **(2700/3200 MW)**
2700/3200 MW	$15.9/18.9 - $16.6/19.7 billion
Per kW	$5,922 - $6,160

If a future 2% inflation rate is assumed, and construction start begins in 2012, the real cost estimate equates to a nominal actual dollar cost of *$20.5 - $22 billion* or *$7,800-$8,131 per kW*. For 3200 MW (CP 3 & 4), the nominal cost is *$24.9 - $26 billion.*

B. Comparison to Other Estimates

The real costs estimated above are within the high end of the range discussed by Luminant, if the Luminant figures are assumed to be real dollars. And the estimate above is closer than NRG's estimate to the range of costs stated by several other utilities planning new nuclear plants. FPL recently set costs as high as $4,540/kW (real dollars without AFUDC) or $8,070/kW (nominal with AFUDC). Progress Energy estimates costs of $6,857/kW (nominal with AFUDC), which is comparable to Georgia Power

[41] Multiple regression analysis by Komanoff Energy Associates in the late 1980s showed a 20%-23% explanatory effect of a plant's percent complete at the time of TMI upon final real costs. *See,* workpapers of Charles Komanoff, Texas PUC Docket No. 6668.

[42] This does not mean that a similar disruptive event like the TMI accident could not occur in the future though. That is a risk beyond the scope of estimating annual rates of future real escalation.

Company's estimate of $6,700/kW. The Northwest Power and Conservation Council, which advises the Bonneville Power Administration, assumed a range of real costs of $5,000 - $6,000/kW, which is generally consistent with this report.[43] Moody's Investor Services recently estimated nuclear capital costs at $5,000 - $6,000/kW, but increased the estimate in May, 2008 to $7,500/kW.[44]

IV. ECONOMICS OF NEW NUCLEAR GENERATION

The real construction cost estimates developed in Section III can be used to assess the relative economics of new nuclear generation in Texas.

A. Levelized Busbar Costs

The most common methodology used by electric utilities for comparing generation plant economics is the levelized busbar cost, a formula for converting the present value of revenue requirements over the life of a facility into an annualized cost per kWh or MWh. Levelized busbar cost analyses have certain limitations, and are generally used as a screening device for selecting technologies.

For purposes of this analysis, the levelized busbar costs are expressed as "real costs." This means that future levels of general inflation are excluded, and discount rates and rates of return are expressed at lower "real rates," rather than the actual rates. Levelized busbar studies frequently are developed in real costs in order to avoid distortions resulting from inflation assumptions. However, care should be exercised in comparing levelized busbar costs developed in this report to levelized busbar costs reported from other sources, even if expressed as "real dollars." Unless the rates of return, discount rates, and capacity factors are developed on the same basis, the results from different studies may not be comparable.

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[43] "Nuclear Power Plant Planning Assumptions," Oct. 2008, Northwest Power and Conservation Planning Council.

[44] "New Nuclear Generating Capacity: Potential Credit Implications," May 2008, Moody's Corporate Finance.

Because combined cycle gas turbine (CCGT) is the predominant technology for new plants built in ERCOT in this decade, a comparison between CCGT and nuclear costs is relevant. Because a CCGT can be constructed faster, the CCGT has a 2012 commercial operations date, compared to the nuclear project's 2021 start of operations. The CCGT's 2008 real cost of construction is assumed to be $710/kW.[45] The low end of the Section III nuclear cost estimate, $5,922/kW is utilized for "screening" purposes. The utility revenue requirement methodology is used to develop capital costs for both plants. Estimates of real operating costs were developed for both projects. The CCGT's heat rate was assumed at 7,000 BTU/kWh and future natural gas prices are based upon EIA's 2008 long term forecast. Additional explanations of the assumptions for the study are set out in the appendix.

The results of the comparison are shown in this table.

Levelized Busbar Costs
Real 2008 Cost, 2700 MW
80% Capacity Factor

	CCGT (2012 COD)		Nuclear Generation (2021 COD)
Total NPV	$17.9 billion		$26.8 billion
Levelized Cost Per MWh	$71.75		$107.38
Ratio: Nuclear to Gas Generation		*150%*	

Based upon this standard utility industry screening method, nuclear generated power is uneconomic relative to the currently available gas-fired alternative.

45 This is consistent with recent experience in Texas and the southwest, as well as the Energy Information Administration's (EIA) 2008 Energy Outlook assumptions.

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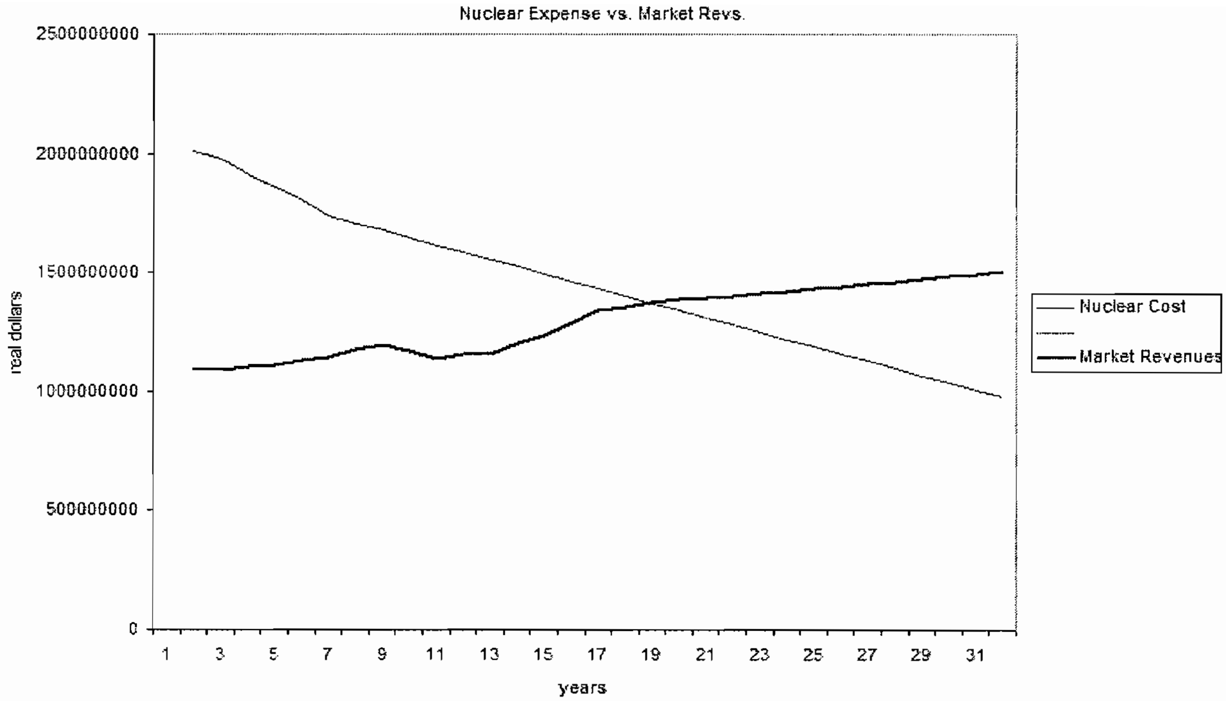
B. Competitive Analysis

The levelized busbar evaluation is based upon regulated utility industry practice. ERCOT is a deregulated wholesale market, which means that a competitive analysis of the new nuclear plant is relevant. In a competitive market, generation companies are likely to compare the expected profit which can be earned by equity owners of the new power plant.

A common financial analysis for project evaluation is the "internal rate of return" or IRR. The IRR derived from a project can be compared to thresholds (or hurdle rates) like the generation company's target return on equity.

An IRR analysis was developed for the new nuclear plant option, using a similar real cost framework to the levelized busbar analysis, excluding equity cost. Costs for annual depreciation, interest on long term debt, property-related expense, production expense, and decommissioning fuel payments were used to develop annual expenses. An ERCOT market price forecast was developed based upon the EIA natural gas forecast. The difference between the nuclear expense and the market revenue is the annual positive or negative margin, which is calculated on an after-tax basis.

Based on this analysis the nuclear project will not be profitable for the owners of the plant. The IRR is -0.7%. The nuclear project is not forecast to earn a positive margin over market revenues for 15 years. Positive margins in 2036 and later years are based, in part, upon rising gas prices. The graph below shows (in real dollars) the nuclear expense versus market revenues.



This analysis would suggest that, in the absence of massive federal subsidies, the nuclear projects proposed in ERCOT face a reasonable likelihood of abandonment.

C. Comparison to Non-Conventional Resources

A comprehensive economic analysis of alternative resources, such as renewables, is beyond the scope of this report. However, the high cost of the nuclear option suggests that a portfolio of alternative resources, perhaps in combination with conventional gas peaking and combined cycle units, could prove to be a more cost-effective capacity expansion path.

Energy efficiency expenditures -- to reduce end use energy consumption by industrial, residential, and commercial customers -- are widely accepted as the most cost effective resources. Current energy efficiency programs (EEP) in Texas are typically one-half as costly as constructing new gas peaking plants. A study conducted for the Texas PUC attempted to evaluate the feasibility of expanding EEP targets over the next 10 years and concluded that 15,000 - 18,000 MW of energy efficiency is economically achievable in Texas over the next 10 years.[46] The 10-year total costs projected by the PUC's consultant imply a levelized cost/kW for the expanded EEP of $87/kW per year -- only 15% of the $579/kW per year levelized real capital cost of the nuclear option.

Renewable technologies with installed construction costs per kilowatt of capacity less than the nuclear project are likely to be more cost-effective, given the minimal or zero fuel costs for renewables. The real installed cost for the nuclear project of $5,922 - $6,160/kW is higher than the following estimated installed costs per kW:[47]

geothermal	$3,000 - $4,000
wind	$1,900 - $2,500
landfill gas	$1,500 - $2,000
fuel cell	$3,800
solar PV (thin film)	$3,900 - $4,000

This discussion is not intended to minimize the advancements for some of the alternative technologies, above which may be required for more effective deployment into the electric grid. For example, wind energy will be a more productive contributor to the power grid if the wind turbines become more reliable/dispatchable through improved storage technologies or offshore siting. However, the massive capital outlays for nuclear power options may drain available financial resources for making advancements in deploying alternative resources.

V. POTENTIAL IMPACT OF FUTURE NUCLEAR GENERATION PROJECTS ON ERCOT MARKET

Because ERCOT is a deregulated power market, one might ask, "Why should consumers care if nuclear power plants are too costly or turn out to be uneconomic?"

[46] "Assessment of the Feasible and Achievable Levels of Electricity Savings from Investor-Owned Utilities in Texas: 2009-2018." Itron, Inc. (2008).

[47] Lazard, Ltd., presentation at 2008 NARUC meetings, Lazard is an energy investment banking house.

After all, suppliers in a competitive market have to absorb economic losses when their production facilities are too expensive.

This might be true, except for two issues: (1) nuclear generators have successfully requested public subsidies, and will continue to press their claims for greater subsidies as costs rise; and (2) ERCOT, like most power markets, is dominated by oligopolistic firms, which results in outcomes which may vary significantly from competitive conduct. As the owners of nuclear construction projects experience cost overruns and realize that the projects will produce large financial losses, the firms may become desperate to appeal for greater public subsidies and, after the plants are constructed, exercise market.

A. Federal Subsidies

The nuclear industry has been successful in obtaining congressional authorization for a wide range of federal subsidies for the new wave of nuclear projects: loan guarantees; production cost tax credits; investment tax credits; and insurance. Because the actual funding of such subsidies are more limited than the nuclear industry desires, the impact upon specific projects is currently uncertain.

Loan guarantees probably impose the greatest risk on taxpayers. The large financial costs to taxpayers of Fannie Mae and Ginnie Mae bailouts during the recent meltdown of the home mortgage industry illustrate the consequences for the public of high risk loan guarantees. Considering that at least 40 nuclear power plants were abandoned prior to completion, during the last wave of domestic nuclear construction, the risks to taxpayers are real and substantial. The Congressional Budget Office has stated that the likelihood of default on nuclear power loan guarantees is *50% or greater*.[48]

Both Luminant and NRG have emphasized the significance of federal loan guarantees to their nuclear proposals; both firms have applied for loan guarantees from DOE. The DOE has already received nuclear project loan guarantee requests totaling $122 billion, even though Congress has authorized only $16.5 billion of guarantees

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48 *Ibidem*. Blake at 10.

currently. DOE has not stated how it will allocate the loan guarantees among the 21 or so reactor applications. The ratio of requested loans to budgeted construction costs suggests that the applicants, on average, expect to finance their projects with 65% federal loans.[49] This might imply equity financing of 30% or less for the projects. Debt leverage of this magnitude on projects like nuclear plants will increase the risk of financial distress and abandonment.

As discussed in Sections II and III, history indicates that cost overruns are likely during the construction of nuclear power plants; and the construction cost and schedule forecasts for many of the current applicants, particularly NRG, appear to be optimistic. As cost overruns materialize during the construction, the applicants will be forced to either reduce the targeted percentage of federally guaranteed financing for the projects or plead for additional federal financing. Assuming that the applicants seek more guaranteed loans, DOE and Congress would then face a dilemma: take on more financial responsibility of increasingly risky and over-budget nuclear projects in an attempt to "save" the guaranteed loan sunk costs; or deny the financing and increase the risk that the applicant will abandon the project and default on the loans. Both outcomes are likely to be very costly for taxpayers.

B. Market Power

The internal rate of return analysis for the nuclear project in Section IV assumed ERCOT market prices which are driven by competitive forces, relatively free of the exercise of market power. However, NRG and Luminant are the dominant power generators in ERCOT, based on market share. Both firms have the potential to exercise market power, thereby driving up generation prices and reducing the losses on their newly constructed nuclear projects.

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[49] $122 billion requested for $188 billion of projects.

Exercising market power to inflate generation prices carries some risks, such as public outrage over high electricity prices.[50] The firms run the risk that the market power abuse will be detected by the Texas PUC or the ERCOT market monitor. However, even if detected, enforcement sanctions may not be severe enough to make the actions unprofitable.[51] If NRG and Luminant complete their nuclear projects, the magnitude of immediate economic losses, as suggested in Section IV, will create strong incentives for both firms to accept greater regulatory risks in order to increase margins on their nuclear power output above competitive levels. Because these two most dominant firms may face similar financial binds, the potential for coordinated pricing action increases. Even without explicit coordination, NRG and Luminant would possess similar motivations, which could lead to parallel pricing with the intent of increasing margins on the operating nuclear power plants.

Industrial organization theory in economics supports the concept that market concentration and market dominance (as measured by market share) creates the potential for, and risk of, a single firm, or several firms in concert, controlling prices, particularly in a capital-intensive industry. Furthermore, an electricity market is uniquely susceptible to market power because of special characteristics, which include: (1) inelastic price responsiveness; (2) the absolute necessity of balancing supply and demand in real time in order to avoid blackouts; (3) the knowledge and information which allows competitors to understand each other's production costs and operational behavior; and (4) the pervasive effects of transmission constraints, which can reduce market size, thereby enhancing the potential for market power.

As demand varies from minute to minute, dominant firms in an electric market may be a "pivotal" supplier for many hours of the year. A pivotal supplier means that the power generation company's installed capacity is required in order for ERCOT to meet

[50] However, experience in Texas and California shows that market manipulators can successfully convince media and regulators, for some period, that the prices are caused by uncontrollable factors.

[51] The Texas PUC Staff found Luminant culpable for market power abuse and sought enforcement actions. As a result of a settlement, Luminant paid a $15 million fine, which was a fraction of the $57 million in damages to the market.

demand. This provides the supplier with virtually unlimited ability to control prices in those time periods either through economic or physical withholding.[52]

A 2004 report by the Texas PUC[53] found that, during periods of zonal transmission congestion, TXU was a pivotal supplier in the North Zone 72% of the time, and Texas Genco (now NRG) was pivotal 36% of the time in the Houston Zone. The ERCOT independent market monitor's report for the two year period through 2007 indicates that a supplier was pivotal in 70% of summer hours and 71% of hours during the non-summer period.[54]

For purposes of quantifying market concentration, this report developed a data base of generation plants and generation owners by ERCOT Zone. Municipally-owned, state-owned, and electric co-operative generation utilities are excluded because those utilities do not have retail open access. Because those utilities continue to operate as regulated bundled utilities, their installed generation is dedicated to monopoly retail loads.[55] Many individual generation plants are operated as limited partnerships, which may conceal control by, or affiliation with, larger generation firms. For that reason, measures of concentration probably are understated.

Because the zonal configuration of ERCOT reflects commercially significant transmission constraints, the zones are the most relevant boundaries for market analysis. This report focuses on the North Zone, which includes Comanche Peak, and the South and Houston Zones, which are most relevant to the South Texas Project.

Together NRG and Luminant control 46% of the relevant generation in ERCOT. Together NRG and Luminant control 93% of relevant coal and nuclear capacity in

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[52] Physical withholding refers to shutting down or reducing a plant's output. Economic withholding refers to bidding a price which is in excess of marginal cost during a period with no shortage of supply.

[53] "Staff Inquiry into Allegations Made by TCE Regarding ERCOT Market Manipulation," Project No. 25937, Jan. 28, 2004.

[54] "2007 State of the Market Report" at 115. Potomac Economic, IMM for the ERCOT Wholesale Market.

[55] If one were to include such generation, only a fraction of the public / co-op generation, corresponding to reserve or excess generation, would be includable.

ERCOT. These high ratios for "two firm" market share demonstrates the potential for collusive or parallel pricing behavior.

Luminant's and NRG's individual market shares in the North and South / Houston Zones is shown below:

<u>Generation Market Share</u>

NRG (Houston & South Zone)	39.2%
Luminant (North Zone)	44.5%

The U.S. Department of Justice's Merger Guidelines presume that a firm with 35% or more market share is capable of raising prices unilaterally. This presumption is particularly appropriate in an electric market, since such high market shares usually ensure that the firms have the ability to control prices by withholding capacity.

The HHI[56] metric frequently is used to measure the potential for market power in a market. The HHI, in combination with demand elasticity values, is mathematically linked to the potential price mark-ups which can be earned in a market.[57] The U.S. Justice Department relies on the HHI as a screening device to evaluate potential anti-trust implications of corporate mergers.

Market power may exist in electricity market even if the HHI indicates a relatively unconcentrated market.[58] This is likely due to the fact that demand elasticity and transmission constraints are not reflected in the HHI. As a result, the HHI may underestimate market power by 10 to 100 times.[59] For that reason, the guidelines, below, for evaluating the HHI should be considered the upper limit for application to electricity markets.

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56 Herfindahl-Hirschmann Index of market concentration.

57 *Power System Economics* at 342-343, Steven Stoft, 2002.

58 The California market exhibited raging market power problems in 2001, despite low HHI values.

59 *Ibidem*, Stoft at 357.

This U.S. Justice Department guidelines define a HHI of 1,000 - 1,800 as moderately concentrated, and a HHI of 1,800 and over as highly concentrated. A transaction which increases the HHI by 100 or more is considered sufficient to raise market power concerns.

Based on the data developed for this report, the HHI values for the ERCOT North and South & Houston Zones are shown below:

	HHI	Characteristic
North Zone	2,227	Highly Concentrated
Houston & South Zone	1,942	Highly Concentrated

Inasmuch as electricity markets could be sub-divided into product markets based upon type of generation facility, a particular insightful use of HHI would apply the metric to baseload, intermediate, and peaking facilities.[60] In the absence of more unit-specific data, a more general approach has been applied in this report, separating solid-fuel (nuclear and coal) plants from gas-fired capacity. Solid-fuel power plants are the pure baseload technologies in ERCOT.

The solid fuel generation HHI for ERCOT is 4,478. This represents an extreme level of concentration, and clearly points to the ability to control prices during time periods when baseload power output is a large proportion of total output. The gap in marginal cost between coal/nuclear and the lowest cost natural gas plants is at least 40%. Therefore, during off-peak and low load periods which are dominated by solid fuel generation, the potential exists for prices to rise substantially above the marginal costs of the solid fuel power production.

The HHI indicates that the gas-fired generation in North Zone and Houston/South Zones are both moderately concentrated. Luminant and NRG are dominant in their

[60] *See,* the HHI analysis in "Criteria for Electric Generation Divestiture in ERCOT," prepared for Texas Office of Public Utility Counsel by J.W. Wilson & Assoc., Sept. 1998.

respective zones, with 27% and 29%, respectively, of gas capacity market share. Firms which are dominant in both baseload and peaking markets can leverage market power in the peaking market as a way to increase profits in the baseload market. An operating nuclear power plant may appear to be a "price taker," but the owner of the nuclear power plant may use its dominant position in the gas generation market to raise margins in peak hours above competitive levels, with the operating nuclear and coal power plants as the largest beneficiary of added profits.

In order to evaluate the HHI impact of adding STP 3 and 4 and CP 3 and 4, the database was supplemented with other planned power plant additions prior to 2012.[61] Luminant was assumed to own 100% of CP 3 and 4, and NRG, 50% of STP 3 and 4. The addition of STP 3 and 4 increases the Houston/South Zone HHI by 153. The addition of CP 3 and 4 increases the North Zone HHI by 269. Both increases exceed the Justice Department's 100 point threshold for the impact of a transaction, thereby indicating that both new plant additions pose a market power concern.[62]

At the time of this report, Exelon had proposed an uninvited takeover of NRG. Besides owning generation in Texas, Exelon also has proposed a nuclear power project in Victoria. If one assumes that Exelon purchases NRG and continues with plans for both the STP and Victoria nuclear power plants, the HHI impact of adding both nuclear projects by a merged entity is 454. This is, not surprisingly, significantly higher than NRG's addition of the STP units alone.

In summary, the addition of STP 3 and 4 and CP 3 and 4 in ERCOT will increase market power concerns. Moreover, the financial impact of those new plants on Luminant and NRG may increase incentives for those firms to exercise market power. Therefore, potentially, the high cost of new nuclear capacity will indirectly translate into higher power prices for Texas consumers.

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[61] Generation plant additions are shown in the Texas PUC's "Update on ERCOT Nodal Market Cost-Benefit Analysi." Resero Consulting, Dec. 2008.

[62] The U.S. Justice Department guidelines apply to corporate mergers, rather than plant additions. However, the guideline is useful for identifying market power issues.

CONCLUSION

John Kenneth Galbraith stated: "The only function of economic forecasting is to make astrology look respectable." Perhaps a similar statement could be made about the promises and forecasts of building nuclear plants cheaply and quickly. To accept those claims, one must ignore the lessons from the last wave of nuclear power construction in the 1970's and 80's. Before that era of building, nuclear power was promised as "too cheap to meter." Realism, instead, acknowledges two fundamental issues for new nuclear generation: (a) Building new nuclear power plants is extremely risky; and (b) nuclear power projects will require the outlay of enormous amounts of capital. Both of these factors could threaten to drain available financial resources for other alternative power technologies.

Looking back at the questions set out in the preface, we can conclude: (1) Nuclear power plants in Texas continue to impose significant capital costs on consumers, and the lower operating costs of the existing nuclear units benefit the owners of generation more than consumers; (2) Nuclear power plants built in Texas have experienced among the worst cost and schedule performances within an industry characterized by its poor cost and schedule performance; (3) New nuclear plants will be much more costly than the conventional alternative, combined cycle gas generation, and are not likely to be profitable in a deregulated ERCOT market; (4) Consumers should care about the plans to move forward with nuclear plants in ERCOT, because cost overruns will lead to increasing demands for public subsidies of deregulated power generation companies, and completion of the plants will lead to the potential for the exercise of market power with an associated increase in ERCOT power prices.

VI. APPENDIX

(Pages A-1 through A-6)

Analysis Assumptions and Inputs

Development of Real Construction Costs in 08 dollars

1. Inflation, net of productivity, for 1987 - 2008 is 2.9%/yr. Construction price index based upon 75% materials and 25% labor. Based on BLS data for constr. materials, construction wages, and productivity.
2. Schedule for first concrete to commercial operation: 9.1 years.
3. Real escalation during construction: 7.9% - 12.5% per year.
4. Real AFUDC rate is 5%. Pre-construction costs = 5% of total.

Development of Levelized Busbar Comparisons

1. Capital Structure: 60% debt/40% equity. 8.1 % real return (10.1% nominal). Debt cost: 6.5% real (8.5% nominal); Equity cost: 10.5% real (12.5% nominal).
2. 31 year depreciable lives on generation plants; 2,700 MW.
3. 15 year tax depreciation for ADFIT on nuclear plant; 20 years on CCGT.
4. Nuclear real cap cost: 15.989 billion; CCGT: 1.917 billion.
5. Current FIT rate is 34%. Factor added for property taxes, state franchise tax, and ordinary insurance.
6. CCGT real O&M cost = $5.24/MWH. Fuel cost = 7,000 heat rate X EIA gas forecast.
7. Nuclear base real O&M cost, incl. fuel and capital additions, is $21/MWH.
8. Based on previous nuclear plant experience, post-COD capital additions and O&M are assumed to be elevated during initial five years of operation; 10% - 30% adder during intial five years.
9. Decommissioning payments for nuclear plant assumed to be 20% higher than current payments for Texas operating nuclear plants.
10. PUC energy efficiency levelized cost based on 15 year life and 7% discount rate.

Development of ERCOT Market Prices

1. Gas price based on EIA 2008 long term forecast. Gas prices escalated beyond end of forecast at 1.4% real escalation rate embedded in EIA forecast.
2. Initial ERCOT heat rate of 8,500, which declines at 1/2% per year to reflect technology improvement and retirement of older plants over time.

Development of Internal Rate of Return

1. Nuclear expense recovery based upon depreciation expense (straight line); interest expense, assuming 60% ratio, 6.5% rate, and declining balance; state and local taxes; O&M expense; and decommissioning payments.
2. ERCOT market revenues minus nuclear expense recovery = margin, which is taxed at 34% FIT rate.

Development of ERCOT Market Share Data.

1. Municipal power, electric co op, and river authority generation excluded, based on assumption that it is dedicated to monopoly retail load.
2. Wind nameplate capacity reduced to 10%, consistent with ERCOT reserve margin planning.
3. If market's firms exceed 50, then smallest PGCs are excluded, consistent with requirement that HHI may only be applied to largest 50 firms. This has minimal effect on result.

DEVELOPMENT OF NUCLEAR REAL COSTS

Cost Estimate , with real cost escalation ($000's) LOW CASE

year	initial	real escalation (7.9%)	Total before AFUDC	AFUDC at real rate (5%)		Real Cost w/AFUDC	
1	1081547	85442.23	1166989	85821.97		1252811	
2	955212.7	75461.8	1030674	141646.8	cumulative	1172321	
3	978754	77321.57	1056076	201532.9	2425133	1257609	
4	1120495	88519.13	1209014	272060.3	3682741	1481075	
5	1218728	96279.52	1315008	351413.7	5163816	1666421	
6	1456360	115052.5	1571413	447555	6830237	2018968	
7	1530312	120894.7	1651207	552493.1	8849205	2203700	
8	1203691	95091.61	1298783	645056.9	11052905	1943840	
9	719922.2	56873.85	776796.1	716149.5	12996745	1492946	
10	174549.3	13789.39	188338.7	761374	14489690	949712.6	
Total	10439573	824726.2	11264299	4175104		15439403	
Plus pre-construction			11813749			15988853	w/pre-const.
			4375.463 per Kw			5921.797	per Kw

HIGH CASE

Real Cost, initial	4070	per Kw
2700 MW	10989000	in $000's
pre construction	549450	
Construction amt.	10439550	

Cost Estimate , with real cost escalation ($000's)

year	initial	real escalation (12.5%)	Total before AFUDC	AFUDC at real rate (5%)		Real Cost w/AFUDC
1	1081547	135193.4	1216741	88309.53		1305050
2	955212.7	119401.6	1074614	146455.7	cumulative	1221070
3	978754	122344.3	1101098	208833.4	2526120	1309932
4	1120495	140061.9	1260557	282303	3836052	1542860
5	1218728	152341	1371069	364971.6	5378912	1736041
6	1456360	182045	1638405	465140.4	7114953	2103546
7	1530312	191289	1721601	574477.5	9218498	2296079
8	1203691	150461.4	1354153	670909	11514577	2025062
9	719922.2	89990.28	809912.5	744950.1	13539639	1554863
10	174549.3	21818.66	196367.9	792016	15094501	988383.9
Total	10439573	1304947	11744519	4338366		16082885
Plus pre-construction			12293969			16632335
			4553.322 per Kw			6160.124

Nominal Costs	21954683
Per Kw	8131.364

Real Cost, initial	4070	per Kw
2700 MW	10989000	in $000's
pre construction	549450	
Construction amt.	10439550	

Development of Nominal Capital Cost for Nuclear Plant Based On 2% General Inflation

Cost Estimate , with real cost escalation ($000's)

year	initial	inflation	real escalation (7.9%)	Total before AFUDC	AFUDC at 7%		Nominal Cost w/AFUDC
1	1078063	1190269	85166.98	1275436	132594.4		1408030
2	952135.5	1072259	75218.7	1147478	222199.5	cumulative	1369677
3	975601	1120659	77072.48	1197731	321594.6	2777707	1519326
4	1116886	1308610	88233.96	1396843	441885.3	4297033	1838729
5	1214802	1451801	95969.36	1547770	581161.2	6135762	2128931
6	1451669	1769576	114681.8	1884258	753740.5	8264694	2637998
7	1525382	1896621	120505.2	2017127	947701.2	10902692	2964828
8	1199814	1521654	94785.27	1616439	1127191	13867520	2743630
9	717603	928296	56690.64	984986.6	1275043	16611150	2260030
10	173987	229572.1	13744.97	243317.1	1381329	18871180	1624646
Total	10405942	12489316	822069.4	13311386	7184440		20495826
Plus pre-construction				13930156			21114595
				5159.317 per Kw			7820.221 per Kw

Ratio to Real Cost
1.320582

Assumptions for Capital Cost Development

Real Cost, initial	4070	per Kw
2700 MW	10989000	in $000's
pre construction	583080.7	
Construction amt.	10405919	

618769.9

	Per Kw
1987 Real Cost post-1979 nuclear average	2576
Escalate to 2008 net of productivity	1.58
Real Cost 2008 without AFUDC	4070.08

Per Unit	months	
Schedule 1st Concrete to COD	109	9.083333 Years

Average Real Cost Escalation, 70s-80's	10% - 16% per year
Lower end of range	0.1 per year
Reduce 21% for TMI	0.079 per year
higher end of range	0.16 per year
Reduce 21% for TMI	0.1264 per year

ECONOMIC COMPARISONS

CCGT O&M Expense
2008 Real Cost
$ 5.24 per MWH

Nuclear Expense
2008 Real Cost (incl. fuel, cap adds)
21 per MWH
Percentage higher in first 5 years:
30%, 30%, 20%, 15%, 10%

	CCGT Operating Costs 2012-2042		Nuclear Operating Costs 2021-2051		ERCOT Market Price 2012-2051				Competitive Analysis, 2021-3051		
year	O&M	Fuel	Production	Decommissioning				heat rate decline	Nuclear Cost		After Tax Margin
1.00	$99,140,112	$902,581,114	$516,559,680	$45,600,000	$	57.92	$ 1,095,991,353	8.50	($2,009,653,413)		$(575,891,912)
2.00	$99,140,112	$904,288,523	$516,559,680	$45,600,000	$	57.74	$ 1,092,574,312	8.46	($1,979,169,622)		$(543,176,725)
3.00	$99,140,112	$920,713,832	$476,824,320	$45,600,000	$	58.50	$ 1,106,857,507	8.42	($1,908,950,471)		$(494,690,080)
4.00	$99,140,112	$930,866,487	$456,956,640	$45,600,000	$	58.85	$ 1,113,467,443	8.37	($1,858,599,000)		$(432,502,791)
5.00	$99,140,112	$948,993,149	$437,088,960	$45,600,000	$	59.69	$ 1,129,474,124	8.33	($1,808,247,529)		$(376,769,177)
6.00	$99,140,112	$967,075,039	$397,353,600	$45,600,000	$	60.53	$ 1,145,239,881	8.29	($1,738,028,378)		$(296,527,715)
7.00	$99,140,112	$996,643,416	$397,353,600	$45,600,000	$	62.06	$ 1,174,354,381	8.25	($1,707,544,586)		$(239,857,216)
8.00	$99,140,112	$1,020,301,829	$397,353,600	$45,600,000	$	63.22	$ 1,196,220,156	8.21	($1,677,060,795)		$(211,348,319)
9.00	$99,140,112	$1,004,171,696	$397,353,600	$45,600,000	$	61.91	$ 1,171,422,355	8.17	($1,646,577,004)		$(176,898,259)
10.00	$99,140,112	$979,639,287	$397,353,600	$45,600,000	$	60.09	$ 1,137,089,910	8.13	($1,616,093,213)		$(151,902,158)
11.00	$99,140,112	$1,001,086,777	$397,353,600	$45,600,000	$	61.10	$ 1,156,174,584	8.08	($1,585,609,422)		$(125,434,703)
12.00	$99,140,112	$1,008,941,606	$397,353,600	$45,600,000	$	61.27	$ 1,159,420,047	8.04	($1,555,125,631)		$ (98,923,193)
13.00	$99,140,112	$1,052,381,200	$397,353,600	$45,600,000	$	63.59	$ 1,203,291,741	8.00	($1,524,641,840)		$ (72,367,320)
14.00	$99,140,112	$1,087,636,968	$397,353,600	$45,600,000	$	65.40	$ 1,237,385,140	7.96	($1,494,158,049)		$ (45,766,778)
15.00	$99,140,112	$1,138,472,716	$397,353,600	$45,600,000	$	68.11	$ 1,288,743,960	7.92	($1,463,674,258)		$ (19,121,255)
16.00	$99,140,112	$1,193,362,593	$397,353,600	$45,600,000	$	71.04	$ 1,344,124,562	7.88	($1,433,190,467)		$ 7,569,559
17.00	$99,140,112	$1,210,701,840	$397,353,600	$45,600,000	$	71.71	$ 1,356,836,069	7.84	($1,402,706,675)		$ 34,305,979
18.00	$99,140,112	$1,236,257,831	$397,353,600	$45,600,000	$	72.86	$ 1,378,549,338	7.81	($1,372,222,884)		$ 61,088,322
19.00	$99,140,112	$1,249,129,882	$397,353,600	$45,600,000	$	73.25	$ 1,385,938,428	7.77	($1,341,739,093)		$ 87,916,907
20.00	$99,140,112	$1,264,119,440	$397,353,600	$45,600,000	$	73.75	$ 1,395,556,841	7.73	($1,311,255,302)		$ 114,792,054
21.00	$99,140,112	$1,279,288,874	$397,353,600	$45,600,000	$	74.27	$ 1,405,242,006	7.69	($1,280,771,511)		$ 141,714,087
22.00	$99,140,112	$1,294,640,340	$397,353,600	$45,600,000	$	74.78	$ 1,414,994,385	7.65	($1,250,287,720)		$ 168,683,331
23.00	$99,140,112	$1,310,176,024	$397,353,600	$45,600,000	$	75.30	$ 1,424,814,446	7.61	($1,219,803,929)		$ 195,700,113
24.00	$99,140,112	$1,325,898,136	$397,353,600	$45,600,000	$	75.82	$ 1,434,702,658	7.57	($1,189,320,138)		$ 222,764,764
25.00	$99,140,112	$1,341,808,914	$397,353,600	$45,600,000	$	76.35	$ 1,444,659,495	7.54	($1,158,836,347)		$ 249,877,616
26.00	$99,140,112	$1,357,910,621	$397,353,600	$45,600,000	$	76.88	$ 1,454,685,432	7.50	($1,128,352,556)		$ 277,039,002
27.00	$99,140,112	$1,374,205,548	$397,353,600	$45,600,000	$	77.41	$ 1,464,780,949	7.46	($1,097,868,764)		$ 304,249,261
28.00	$99,140,112	$1,390,696,015	$397,353,600	$45,600,000	$	77.95	$ 1,474,946,528	7.42	($1,067,384,973)		$ 331,508,731
29.00	$99,140,112	$1,407,384,367	$397,353,600	$45,600,000	$	78.49	$ 1,485,182,657	7.39	($1,036,901,182)		$ 358,817,754
30.00	$99,140,112	$1,424,272,980	$397,353,600	$45,600,000	$	79.04	$ 1,495,489,825	7.35	($1,006,417,391)		$ 386,176,674
31.00	$99,140,112	$1,441,364,255	$397,353,600	$45,600,000	$	79.58	$ 1,505,868,524	7.31	($980,782,386)		$ 410,385,638
					$	80.14	$ 1,516,319,252	7.28			
					$	80.69	$ 1,526,842,508	7.24		total	$(508,587,807)
					$	81.25	$ 1,537,438,795	7.20			
					$	81.82	$ 1,548,108,820	7.17			
					$	82.38	$ 1,558,852,494	7.13			
					$	82.96	$ 1,569,670,930	7.10			
	$1,308,712,398	$14,095,397,596	$5,603,472,101	$601,948,940	$	83.53	$ 1,580,564,446	7.06		IRR	-0.7%
					$	84.11	$ 1,591,533,563	7.03			
					$	84.70	$ 1,602,578,806	6.99			

NPV Comparison

	CCGT	Nuclear
Total Operations	$15,404,109,994	$6,205,421,041
Total Capital	$2,516,362,286	$20,615,759,000
Total NPV	$17,920,472,280	$26,821,180,041
levelized	$1,357,546,266	$2,031,809,890
per mwh	$71.75	$107.38

2021-2051	$17,833,115,060
	$17,833,115,060
levelized	$1,350,928,613
per mwh	$71.40

South Texas Nuclear Project
Plant Balances for Stranded Cost Recovery
$000's

Texas Central Company

	Acct.	gross	accumulated depreciation
	320	$ 4,653	
	321	$ 1,032,436	385676
	322	$ 713,919	266691
	323	$ 159,293	59505
	324	$ 418,773	156437
	325	$ 32,647	12196
subtotal		$ 2,361,721	880505
Net Plant total		$ 1,481,216	
Nuc fuel inventory		$ 28,741	
Total Net Plant		$ 1,509,957	

Center Point Electric

	Acct.	gross	accumulated depreciation
	320	$ 5,825	
	321	$ 1,093,606	425705
	322	$ 788,942	289524
	323	$ 167,227	92850
	324	$ 438,273	172661
	325	$ 28,374	1651
subtotal		$ 2,522,247	982391
Net Plant total		$ 1,539,856	
Nuc fuel inventory		$ 30,465	
Total Net Plant		$ 1,570,321	29% Percent total Net Plant

Texas Central Co.
Securtized Regulatory Assets

STP deferred acctg.	482447
Mirror CWIP	393854
Total Reg. Assets	876301
Total TCC Cost	$ 2,386,258

Center Point Electric
Securitized Regulatory Assets

STP Deferred acctg.	535787
STP Litigation Cost	35414
DOE Decon. Cost	5479
Total Reg. Assets	576680
Total CNP Cost	$ 2,147,001

Total STNP Non Bypassable Costs		Per Kw
Center Point Elec.	$ 2,147,001	
Tex. Cent. Co.	$ 2,386,258	
Total Recovery	$ 4,533,259	$ 3,858.09

STP Sales Proceeds ($000's)

	CNP Proceeds (81%)	At 100%	
First TGN Purchase			
Nuclear Assets	$ 700,000	$ 864,198	
Transaction Total	$ 2,931,000	$ 3,618,519	
Nuclear as %	24%	24%	
PUCT Assumed TGN Sale Price		$ 3,395,000	
PUC Reduction to Sale Price		94%	
Implied Nuclear Sale Price		$ 810,815	
AEP TCC Sales Proceeds		$ 314,000	
			per KW
Total Sales Revenues Credited to Ratepayers		$ 1,124,815	$ 957.29
Total STP Assets, Net of Sales Revs, Paid by Ratepayers		$ 3,408,444	$2,900.80
Total STP Plant, Net of Sales Revs, Paid by Ratepayers		$ 1,955,463	$1,664.22
Second TGN Purchase (NRG), per NRG 2007 SEC 10-K		$ 6,200,000	
STP Net Plant Reported by NRG		$ 2,588,000	
Total TGN Production Plant Purchased by NRG		$ 9,336,000	
Ratio		28%	
Prorate NRG Transaction Price to STP		$ 1,718,680	$1,462.71