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NP2010 TEXAS GULF COAST NUCLEAR FEASIBILITY STUDY FINAL REPORT

Disclaimer: The opinions, findings, conclusions, or recommendations expressed in this material are those of the authors, and do not necessarily reflect the views of the Department of Energy.

PROJECT TEAMS

The work involved in the creation of this report was performed principally by EnergyPath Corporation (under contract with TIACT) and Sandia National Laboratories. Major EnergyPath project subcontractors included Dr. Geoff Rothwell, Value Analytix Limited, Black and Veatch Corporation, Morgan and Lewis LLP, and E&MC Group LLC.

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INTRODUCTION

PROJECT OBJECTIVE

The primary objective of this project was to ascertain the feasibility of siting and commissioning a nuclear plant to serve the future energy needs of Texas Gulf Coast end users.

An immediate goal is to enable Texas Gulf Coast petrochemical producers to offset the cost of increasingly expensive natural gas feedstock, thereby avoiding the progressive transfer of this industry to foreign shores. By adding abundant clean energy to the grid, a Gulf Coast nuclear plant would additionally support the goal of cleaner air in Texas, given that most regions of high population within the state are currently judged to be non-attainment areas.

A longer range project objective is initiation of a nationwide movement away from natural gas and toward nuclear energy for the generation of electricity, thereby both reducing carbon emissions and making reasonably priced natural gas available to residential and commercial users and to the U.S. chemical industry.

BACKGROUND

In 2001, the prospect of U.S. natural gas prices permanently exceeding $5/MBtu led members of the Texas Institute for Advancement of Chemical Technology (TIACT) to initiate this study. Recognizing that natural gas is used as both fuel and feedstock within the chemical industry, TIACT industry members found it difficult to profitably operate in a global market at high levels of volatile natural gas prices.

A major cause of the rise in U.S. natural gas prices is increased demand for natural gas in the generation of electricity. According to the Energy Information Administration (EIA), over 95% of all new power plants built over the last ten years use natural gas. Furthermore, EIA has projected that approximately 90% of all new power plants commissioned in the coming decades will use natural gas. This increase in electrical generation demand - coupled with a continued decline in U.S. natural gas well head output - is projected to drive natural gas prices ever higher for the foreseeable future.

PROJECT OUTLINE

By way of ascertaining economic and technical feasibility, this study provides a comprehensive roadmap for the financing and construction of a Gulf Coast nuclear plant. Roadmap scope includes potential auxiliary units to produce hydrogen, oxygen, and desalinated water. Development of the Gulf Coast nuclear plant roadmap is divided into the Tasks listed in the Table of Contents.

At the outset, it was envisioned that the majority of plant output would serve the Gulf Coast chemical industry with electricity and steam, with remaining output used to produce hydrogen, oxygen, and water - depending upon related economics. Any residual electrical output would be sold through deregulated wholesale and retail power markets.

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EXECUTIVE SUMMARY

INTRODUCTION

"Why are more nuclear power plants not being built?"

This was the question on everyone's mind at two meetings of large chemical manufacturers hosted by the Texas Institute for the Advancement of Chemical Technology (TIACT) in 2003.

Although everyone, including speakers from the nuclear industry and government, seemed to agree that building more nuclear power plants was a very good idea, no one could put their finger on exactly why none were.

For the chemical manufacturers located on the Texas Gulf Coast the lack of a ready answer spurred them into action.

Increasing natural gas prices is a very serious problem for chemical manufacturers. Natural gas is a feedstock in the production of industrial and everyday chemicals and it is the primary fuel in Texas (over 70%) for generating the electricity that chemical manufacturers use in large quantities. Higher natural gas prices represents a sea change, as one industry executive put it, that has resulted in lost business and plant closings throughout the industry.

The chemical manufacturers in Texas believe that the long-term solution is the construction of new nuclear plants as a way to lower electricity costs and to prevent further diversion of natural gas stocks to electrical power generation. They also believe that it is in their best interest to pro-actively support efforts to do so. Their support has been provided through TIACT who has partnered with the Department of Energy to undertake and co-fund this study to see if the nuclear generation option is a feasible business proposition in Texas.

OVERVIEW OF THE RESULTS

Construction of a new plant in Texas is not being hindered or delayed by a lack of:

- Ready customers willing to enter into long term power purchase agreements
- Good sites on which to locate one or two units
- Pre-licensed, advanced nuclear plant designs and qualified suppliers
- A manageable, although not fully tested, licensing process
- Companies ready to join an ownership consortium under the right conditions
- Recognition of the many "non-economic" benefits of nuclear power.

What is preventing a new plant from being built is the lack of a business model that can overcome the formidable financial risks confronting the would-be owners, especially for a plant that is to be located in the deregulated ERCOT (Electric Reliability Council of Texas) market. These risks appear daunting and are no doubt one of the chief reasons that no nuclear plants are being built in Texas or elsewhere in the U.S. However, an important finding of this study is that these risks should not inhibit a management team from proceeding with project development. By employing an option or a tollgate approach, as described below, the project developer has the ability to delay or abandon the project at any time prior to construction. The investment of development capital, which by design will be small when risks are highest, would be lost but a far greater loss would be avoided. This management flexibility is not taken into account when using standard capital budgeting tools and erroneously leads to a net present value (NPV) of negative $100 million and therefore, the project would not be undertaken. However, when this management flexibility is taken into account then the results are entirely different, leading to a strategic net present value of $100 million, and justifies immediate execution of the project. The difference between the two is that management can avoid further investments leading up to construction if they appear to be uneconomic, and standard capital budgeting tools do not recognize this.

This is one of the studies principal findings. It is a particularly important one given that the purpose of the study was to develop an approach that would initiate a construction project. This is not a study to identify policy options that would make nuclear construction more likely. There are already many such studies available.

The most recent study is *The Economic Future of Nuclear Power* (the University of Chicago, December 2004). It is upbeat about the long-term prospects but concludes that nuclear electricity is not now competitive with either combined cycle or coal. This near term condition can be overcome with a combination of limited and short-term federal financial incentives to help surmount the unique financial hurdles associated with building the first few new nuclear plant designs (first time costs, e.g.). Their conclusion is: “After engineering costs are paid and construction of the first few nuclear plants has been completed, there is a good prospect that lower nuclear LCOEs[1] can be achieved and that these lower costs would allow nuclear energy to be competitive in the marketplace.” This is an upbeat but not a definitive assessment.

The authors of *The Future of Nuclear Power* (Massachusetts Institute of Technology (MIT), 2003) reached a similar but not identical conclusion. New nuclear plants are not now competitive but can be made so by decreasing total overnight capital costs from $2,000/kW to $1,500/kW, reducing Operation and Maintenance (O&M) costs further, shortening the schedule and so on, presumably as prerequisites for (rather than as the result of) building the first few units.[2]

We agree with these studies in that it will be difficult for the first one or two units to be competitive with currently applied coal and combined cycle technologies. Where we differ is what to do about it. The Chicago and MIT studies make reasonable recommendations including reducing plant capital costs and creating tax incentives. However, these solutions require others to act (plant suppliers and Congress, for example) and are therefore outside the direct control of project developers.

1 Levelized Cost of Electricity

2 The total overnight capital cost includes: Engineering, Procurement and Construction (EPC) cost, Owners cost and contingency. It does not include project financing costs.

This study, on the other hand, concludes that there is a reasonable strategy to move a nuclear plant project forward by addressing the issues of uncertainty and risk that are within the ability of project developers to influence. We do believe that there is a case to be made for government assistance which would quite clearly change the economics of initial units. Our analysis concluded that government debt guarantees would have the most impact on the overall appeal of the project to lenders. In this context the guarantees are not subsidies, as some critics believe, but rather a government vote of confidence in the future of nuclear power, something that most investors feel is absent today.

THE KEY RESULT–A NEW BUSINESS MODEL

The key result of this study is the creation of a new business model that can help overcome the current paralysis by breaking the project financially into manageable stages. At each stage the need for development capital is appropriately matched to the level of risk. This approach differs from others that we have seen because it does not require a one-time, irreversible decision for investors to commit to the multi-billion dollar investment needed to build a new unit. These results are derived from an advanced economic and financial analysis that recognizes the shortcomings of the traditional capital budgeting approach and suggests an entirely new roadmap for constructing a nuclear plant.

This new business model also uses an entirely new risk management strategy, one that attempts to reduce the most important risks very early in the development of the project when capital outlays are smallest. To quantify the benefit of these actions required the application of a financial evaluation derived from financial options theory. Real options analysis recognizes that nearly all investment decisions, in reality, have options embedded within them (which go unrevealed in a standard NPV analysis), and that the value of these options may give rise to decisions completely at odds with those of a standard NPV analysis.

In this case, it counsels that the project developers should begin funding activities to eliminate uncertainties that could render the plant uneconomic. It also specifies how much spending is justified. Furthermore, our analysis reveals there is enough “option value” to justify moving forward immediately with the first phase of this project.

And it doesn’t end there.

As validated by the study’s outside financial consultant, the management structure of the team most likely to be successful with this new business model looks more like that of a Silicon Valley entrepreneurial group than an electric utility. This team will view the nuclear plant as an option to be exercised when and if conditions are right, and must be able to communicate this information to potential investors and owners.

SUMMARY DISCUSSION OF THE BUSINESS MODEL

The business model has the following key elements:

- **Close relationship with end users.**

End users are important because they will buy electricity directly from the owners via Power Purchase Agreements (PPAs), or own part of the plant itself. It is, therefore, important to understand their business and energy needs well, in order to fashion PPAs or an ownership stake with enough appeal that they would make commitments in advance. This enables the project developer to secure the needed financing on reasonable terms. A reasonably thorough understanding of end user needs was developed by using Six Sigma methods and conducting a significant number of meetings with chemical manufacturers. The results are discussed in the Task 1 report.

- **A non-traditional ownership structure**

The nature of the ownership arrangement is shaped by the location of the proposed plant in the deregulated ERCOT market and the involvement of end users. The first consideration rules out ownership by a regulated utility with recourse to a customer base and the opportunity to recover costs through a rate base. Because a true merchant plant of any kind, let alone a nuclear one, would find it difficult to obtain financing, it is necessary to have a significant amount of the plant's output under contract before construction begins.

The solution recommended here is to create an ownership structure that is something of a cross between that used successfully by Teollisuuden Voima Oy, a Finnish utility, and by the owners of South Texas Project (STP). This concept is illustrated in the following table.

Owner	Share	MWs
Industrial end users	15%	210
Municipal utilities	50%	700
Investor owned utilities	10%	140
Private Investor Groups	15%	210
Nuclear Industry companies	10%	140
TOTAL	100%	1400

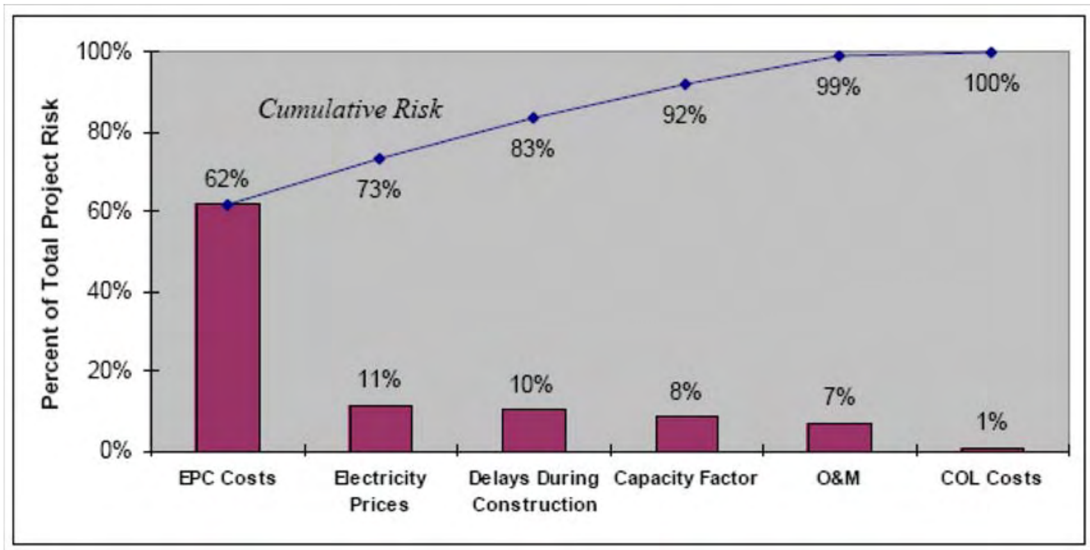
As the Task 5 report details, the participation of those organizations listed in an ownership consortium is quite plausible. The industrial companies would consume their share of the electricity. The municipal and investor owned utilities would distribute the electricity to their core customers and use it to compete for new customers. The electricity owned by the private investor groups and nuclear industry companies would be marketed by themselves or through Load Serving Entities (retail marketers, for example). If subscriptions turn out to be less than 100%, the remaining output would be sold by the consortium itself through a portfolio of short, medium and long-term Power Purchase Agreements with chemical manufacturers who have not opted for an ownership stake. The steps needed to form a consortium, launch the startup activities and the associated costs are discussed in the Task 5 report.

- **An innovative risk management strategy**

A principal finding of this study is that new nuclear plants are not being ordered and constructed because potential owners and investors are waiting for uncertainties to be resolved with the passage of time (e.g., environmental legislation) and the creation of U.S. energy policy favorable to nuclear development.

The risk management plan recommended here can accelerate the resolution of some of these uncertainties, including some of the key uncertainties, such as Engineering, Procurement, and Construction (EPC) costs. This will permit the project to move forward quite a bit sooner-in particular in time to meet the DOE's NP2010 program goals.

The key risks confronting the project development team at the outset of the project are shown below.



A few of the elements of the recommended risk management strategy are delineated below. These are to be pursued in the first phase of project development that would seem out of order if a more traditional approach were to be taken.

In Phase 1 of the project:

1. *Secure binding committments for plant capital costs*. Request bids and enter into an exclusive arrangement with a supplier that 1) commits the consortium to ordering the plant from the supplier when the Nuclear Regulatory Commission (NRC) approves the combined construction and license permit (COL) and financing is approved and 2) commits the supplier to build the plant at the price agreed to. In order to encourage as many bidders as possible to participate fully, our plan calls for partial funding of the bidders proposal costs by the consortium.

2. *Undertake an early community outreach program.* The following scenario is familiar to nuclear industry veterans: an organization ideologically opposed to nuclear power adroitly exploits the

legal system to halt or delay construction in the absence of seemingly compelling legal reasons to do so. The outreach program would not only marshal local support for the project, which is known to exist, but would help to neutralize or blunt some of the opposition to the project, especially that which is likely to come from nationally based organizations opposed to nuclear power. There are examples of this approach being successful with the permitting of combined cycle plants at controversial locations.

As explained in the report on Task 8, these action plans will mitigate two of the most important risks, the capital cost of the plant and the potential for delays during construction. The remaining project risks and related risk reductions actions are also discussed.

- **A Tollgate Approach to Investing**

In order to attract the development capital needed to proceed with this project, a tollgate approach was developed. This approach deconstructs the risks to investors so that they can be addressed in a stepwise manner that makes financial sense. Risk and investment are appropriately matched. At the first tollgate where risk is high, a small investment of development capital is called for. It is likely that an investor with an appetite for such risk can be found, provided there is a significant upside (as there is in this case.) At the last tollgate, when risks have been reduced to a level acceptable to a much broader group of investors, an investment of the size needed to construct a nuclear power plant, can be more readily obtained at reasonable terms.

There are three tollgates for the Texas Gulf Coast Nuclear Project as show in the table.

The Roadmap to Constructing a Nuclear Plant

The Tollgate	The Toll	Before Passing Through the Tollgate (Bridging Criteria)	Information to be Acquired or Actions to be Taken After Passing Tollgate
#1	$10 to $25M	• Raise development capital for purposes of paying the toll. • Assemble a project development team, including supporting legal, engineering and public relations firms. • Develop a strategic plan for for the project, extending the work in this study further. • Create an ownership consortium	• Enter into an Agreement in Principle for host site • Prepare a set of technical bid specifications based upon the Electric Power Research Institute (EPRI) requirements, updated and customized for this project • Request and evaluate bids for total plant supply. • Negotiate Engineering Procurement and Construction (EPC) contract with plant supply team • Initiate the community outreach program • Make initial contacts with lending sources to identify cost of funds and likely obstacles. • Hire a leading environmental firm to prepare and defend the Environmental Impact Statement.
#2	$30-60M	• Raise development capital for purposes of paying the toll • Have in hand a binding commitment to an EPC cost that yields a total overnight capital cost of no more than $1500/kW[3] • Finalize the site Agreement. • Develop a plan for preparing and supporting the COL Application.	• Obtain PPAs for balance of plant output not committed to the owners. • Prepare and submit the COL application for NRC approval. • Develop a legal strategy to combat delays during construction. • Develop a strategy to obtain construction funding. • Obtain debt financing at least on a tentative basis.
#3	$2.5 to 3.0B	• NRC approval of COL • Obtain construction funding • Permanent financing obtained • Finalize ownership structures	• Construct the plant • Put in place plant management team either by outsourcing or by recruitment. • Load fuel and begin startup • Refinance and adjust to permanent capital structure

The key benefit of this approach is that it allows for uncertainties to be resolved when capital outlays are lowest, providing the opportunity to forego the remaining investment if uncertainties are resolved unsatisfactorily. It is obvious that the initial capital outlays involve a significant risk and this in turn requires investors with a concomitant appetite for such risks. However, such financing can also be provided by those who would benefit greatly from knowing the terms, conditions and prices negotiated with nuclear suppliers with the latest generation of advanced nuclear plants. The same can be said of the capital outlays for the COL process-where the new licensing process put into place by the NRC would be tested for the very first time. There is significant value in both of these activities.

The Task 6 report goes into considerably more detail and includes a brief discussion of the analytical tools[4] needed to quantify the value of this tollgate approach.

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3 In the analytical results discussed in Task 6, this is the total overnight capital cost for which the NPV is zero or slightly positive, assuming the median electricity price forecast.

4 This study's quantitative analysis is based upon "real options" theory for which there is a significant body of work upon which to draw.

- **A Financing Plan that Builds upon the New Business Model**

Given the barriers to building a new nuclear power plant in the United States, any plant up and running before 2020 is more likely to be developed by a new company driven by entrepreneurs, created specifically for the task of building this plant. Further, for any group to succeed in breaking the nuclear logjam they will have to behave more like Silicon Valley entrepreneurs than big corporate entities and that will include a recognition that they will have multiple rounds of financing. As each tollgate is passed the value of the plant will increase thus offering a potentially large capital gain for investors willing to assume the risk involved.

THE PROJECT FUNDAMENTALS

In addition to creating the business model described above, this study carefully reviewed the project fundamentals to ensure that they meet the expectations of both end users and investors. These expectations were captured in a set of CTQs[5] for each group developed through interviews and discussion with various parties. This study finds that project has with one exception strong fundamentals. The exception is plant capital costs.

- *Offtake Agreements*. There is reason to believe that long-term offtake agreements for most of the plant's output can be found and generate predictable revenues for the life of the loans (twenty years.) This is conditioned upon completing the first phases of project development and having a supplier under contract to deliver a plant for under $1500/kW (total overnight capital cost) or possibly less if forecasted electricity prices should fall below expected levels. The functional ERCOT market is a strong enabling factor.

- *Available Sites*. The existing nuclear plant sites in Texas score high in terms of being able to host one or two additional units. This conclusion was reached after performing the screening analysis laid out in the EPRI Siting Guide.[6] These sites were found to be environmentally superior on the basis of an evaluation done by engineers of the Black & Veatch Corporation. This evaluation was based upon a review of the sites against a selected number of safety and environmental criteria also found in EPRI's siting guide. This is discussed in great detail in the Task 2 report.[7]

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5 CTQ is Six Sigma terminology for those features that are "Critical to the Quality" of the product or service as seen through the eyes of the customer. CTQs are stated in measurable terms and are assigned weighing factors by customers.

6 "Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application", EPRI Technical Report 1006878, March 2002. It is used here by permission of the Electric Power Research Institute. TIACT and EnergyPath are very grateful to EPRI for their close cooperation and support of this study.

7 Black & Veatch performed this evaluation and other related work pro bono. TIACT and EnergyPath are extremely grateful for their support and expertise.

- *Competitive, Dependable Plant Designs*. Nine advanced designs were evaluated against a complement of end user and investor CTQs. The information needed for this evaluation was obtained with the cooperation of the various suppliers who provided significant evaluation documentation and discussed their offerings with a team of industry experts at separate half-day meetings. All designs represent impressive advances in nuclear plant technology and design. However, the ABWR (both GE and Toshiba) offers a slightly better fit to the unique CTQs for the TIACT study. Four other designs, the AP1000, ESBWR, ACR700, and the EPR, are compelling alternatives each of which could, with appropriate contractual terms, fulfill most of the project unique CTQs. In this study significant values were assigned to licensing and final design engineering status. The detailed assessment of these and other plant designs is the focus of the Task 3 report.

  This study finds that these plants, from a technical and performance standpoint, are acceptable and indeed exceed basic requirements. However, without the risk mitigation actions outlined above, there exists too much uncertainty over the true capital cost of these offerings. There is more confidence in the construction schedules, which range between 45 and 51 months for the designs noted above, as measured from first concrete to commercial operation.

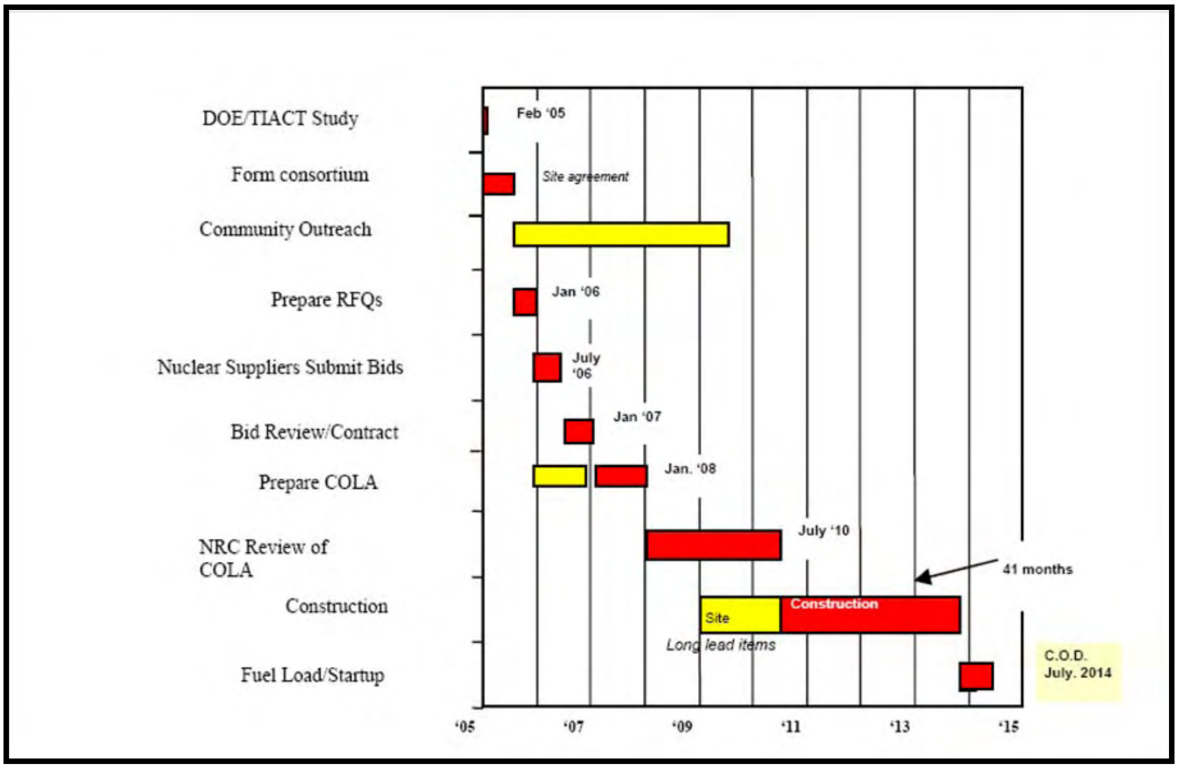
- *Manageable Licensing Process*. The legal firm of Morgan Lewis, the recognized expert with respect to NRC licensing, reviewed the applicable regulations as they pertain to a Texas project. Based upon that review and with consideration for end user and investor CTQs, this study recommends that the COL application reference an existing certified design (currently ABWR with addition of the AP1000 expected by the end of 2005) or a design for which a Design Certification application has been submitted (multiple designs expected to meet this criteria in the near term) and should include the site safety and environmental analyses. An Early Site Permit program is not recommended.

There are actually two licensing processes. The first is the COL review by the NRC that is likely to take three years or perhaps less for an applicant fully intent upon building a plant. The risk associated with the COL review was evaluated to be quite small and the analytical results in Task 8 show clearly that it contributes little to the overall project risk. The other licensing process is that which occurs after the start of construction, the part of the project that for the owners is the most anxiety ridden. Any schedule delay caused by legal or regulatory action (or inaction) can have huge financial consequences. Indeed it is the second highest contributor to overall risk and the one cited most commonly as the CEO’s worst nightmare. Examination of the risks associated with this stage of licensing shows, however, that these risk are not as large as commonly thought and can be pro-actively managed, as the Task 8 report describes.

PROJECT SCHEDULE

The CTQs of the chemical manufacturers interviewed for this study suggests that there is a growing sense of urgency with respect to building more nuclear capacity.

Because of the relatively long time period required to construct a nuclear facility, a certain amount of aggressiveness is required to prepare a schedule that responds to this need for quick action. This is done by analyzing the schedule for opportunities to advance key milestones by taking a small amount of risk (for example, by ordering long lead items for the reactor vessel prior to NRC approval of the COL). On the other hand, one must account for certain realities. A project schedule reasonably balanced between aggressive and realistic estimates of the length of various activities is shown in the figure below. If project development work begins in 2005, then we project that construction would begin in 2010. This presupposes that with a relatively small degree of risk taking, the long lead items are ordered and site preparation is begun a year and half earlier, at the beginning of 2009. Estimates of how long it will take for the NRC to approve a COL application range from 2 to 3 years as noted above, with the former thought possible for an applicant who is committed to construction. We used 2 ½ years as the basis for our analysis. Also, we use 48 months for the construction schedule (first concrete to commercial operation) including 7 months for startup and commissioning. These are the average values of the schedule information provided by the plant suppliers (Task 3).

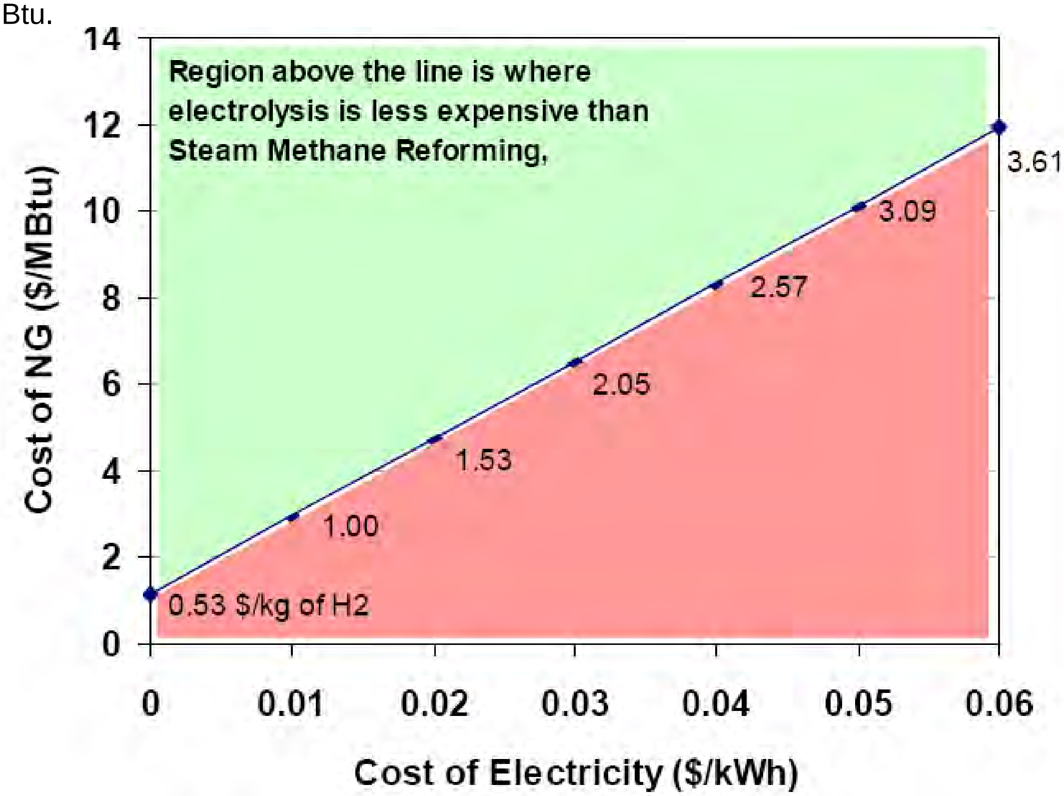


SPECIAL STUDIES

As part of the Task 3 technology assessment effort, a review of current and future hydrogen generation and desalination technologies was completed by our technology evaluation partner, Sandia National Laboratories. This analysis concluded that the reviewed hydrogen generation and desalination technology options do not have a significant impact on the selection of a nuclear generation technology for the Texas Gulf Coast Nuclear (TGCN) plant. They may, however, offer economic opportunities. Brief summaries of these two technology assessments follow and with more detailed results found in the Task 3 report and corresponding appendices.

HYDROGEN

An analysis of cost of hydrogen production by the present method of steam-methane reforming (SMR) was compared with the cost of producing hydrogen by conventional electrolysis. The graph, below, prepared as described on page 3-13, Appendix 3, relates the cost of natural gas and the cost of electricity at which hydrogen produced by electrolysis is equal to the cost of hydrogen produced by steam-methane reforming (SMR). For example, if electricity costs $0.02/kWh, hydrogen by electrolysis costs less than hydrogen by SMR, if the cost of natural gas is greater than $4.50/MBtu.



Cost of Natural Gas Vs. Cost of Electricity Where Electrolysis Becomes Competitive with Steam Methane Reforming

Thus, since the cost of production of hydrogen by electrolysis is competitive with the cost of hydrogen produced by natural gas, at many combinations of natural gas prices and electricity costs as shown in the figure above, the production of hydrogen by electrolysis represents a realistic market for some of the electricity produced by a Texas Gulf Coast Nuclear Plant. This proposition rests on the assumption that the price of natural gas will remain relatively high. Other than EIA, there are several who believe that natural gas prices will remain relatively high, including Sempra (The Wall Street Journal, December 27, 2004) and experts from the John F. Kennedy School of Government (Dow Jones Newswire, January 7, 2005). The present hydrogen pipeline located along a portion of the Texas Gulf Coast would provide an outlet for hydrogen and its use in the petrochemical industry. The availability of an electrolysis unit and a hydrogen pipeline would also permit the production of hydrogen as a device for leveling the electrical loads.

WATER

An extensive study of water desalination was carried out. Reverse Osmosis was found to be the most widely used as well as the most economical with the projected cost of water at $0.29/m^3. The basis for this cost was a production rate of 100,000 m^3/day, plant life of 25 years, 7% interest rate and an electricity cost presumed to be $0.06/kWh (as taken from the grid, not the proposed nuclear plant). This price, $0.29/m^3, assumes low salinity brackish groundwater is treated by reverse osmosis. At a higher salt content, the cost of water is projected to be $0.73/m^3. Typical costs of water in Texas currently can be as little as $0.08/m^3 for fresh ground water or as much as $0.67/m^3 for fresh surface water. A majority of the cost of water is due to the initial capital costs of a plant. Therefore, running such a desalination plant only during off-peak hours leads to less production and higher overall costs. As is evident from the prices stated above, there is a demand in many areas of Texas for water produced by reverse osmosis and with it a set of potential customers of nuclear electricity not fully exposed.

Since the cost of water produced by Reverse Osmosis is in the competitive range of fresh surface water, there are many areas in Texas that would be in the market for this product. For example, the City of San Antonio (a fast growing area) is actively engaged in arranging for its future water supply. Also, the fast growing area of South and Southwest of Houston are expected to have future water needs. The marketing plan for the electricity produced by the TGCN plant should consider these potential markets.

SUMMARY

- With timely action in 2005, the project schedule can meet the goals of NP2010.
- There is indeed a business case to be made for a privately financed new nuclear plant, provided the business model put in place by the owners recognizes the risks and uncertainties that inhibit the financing of the project. In support of this business case are many strong project fundamentals.
- The economics of the project are determined by uncertainties and risks that can be quantified and actively addressed by the project development team using a “tollgate” approach that keeps development costs to a minimum.
- The tollgate approach is itself the roadmap.
- An Immediate action for early 2005 is to raise the capital needed to fund the activities of a core project development group that will begin to marshal the interest that many parties have for proceeding with a new plant. In particular, the project development team will create the legal framework for the creation of a new consortium and recruit interested parties.

CONCLUSIONS

The chemical manufacturers that make up the membership of TIACT continue to be strong advocates of nuclear power. Likewise, members of Texas civic groups such as Rotary Clubs commonly ask: Why aren't new nuclear power plants being built? These samplings suggest significant and widespread support by other large end users in the industrial, private and public sectors. Recent developments such as the continued rise of natural gas prices, forecasts that show surplus capacity in ERCOT disappearing more rapidly than previously expected, and the prospects of environmental restrictions on the use of fossil fuels serve only to reinforce TIACT's belief that additional nuclear generating capacity is needed.

A year ago the path that led to the construction of a new nuclear plant could not be discerned. Now with the results of this study in hand, TIACT has a roadmap that points the way forward. In particular, the study has described a business model that can effectively grapple with the technical, financial, and risk issues that make project development of a nuclear plant in the de-regulated ERCOT market uniquely challenging.

It is the intention of TIACT to use the findings and conclusions of this study as the means for marshalling the interest that many parties in Texas have expressed for moving forward with a nuclear project. Indeed, one of the most important and encouraging findings of this study is that such interest is both significant and widespread. It includes the interests of large end users in the chemical industry, other large end users in the private and public sectors, ERCOT market participants, and non-traditional outside investors. The fictional consortium "Texas Gulf Coast Nuclear, Inc. (TGCN)" represents a potential focal point for this widespread interest. If made into a reality, this consortium would be the entity to which TIACT could make a "handoff" so that the momentum created by this study would continue to grow. It is important that this handoff take place in 2005. The most immediate challenge is to raise the development capital needed to form the Texas Gulf Nuclear consortium, which would then initiate the tollgate process described in this study.

TIACT and its members recognize the importance of adding new nuclear capacity in Texas. The benefits of nuclear energy extend well beyond ensuring that key businesses and employers in Texas remain healthy and competitive. TIACT believes that the citizens of Texas will also be the beneficiaries of a source of electricity that emits no chemicals and greenhouse gases to the air, provides energy security and diversity, and will help put downward pressure on electricity bills.

Now is the time to move forward.

TASK 1

DEVELOP END USER REQUIREMENTS

TASK 1. DEVELOP END USER REQUIREMENTS

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TASK 1. ESTABLISH END USER REQUIREMENTS

1.1. INTRODUCTION

The overall purpose of this Study is to create a roadmap and specific action items that end users, as represented by the member companies of TIACT (the Texas Institute for the Advancement of Chemical Technology), can use to initiate the construction and operation of a new nuclear power plant in Texas. The intent is that some of the plant's output would be used to serve the needs of the chemical industry for electricity, steam, hydrogen, oxygen, and water and that any remaining electrical output would be sold through wholesale and retail power markets. It is generally agreed that a new nuclear plant would provide important benefits not only for large end users but for all end users, regardless of size.

The objective of Task 1 is to understand what factors energy managers take into account when purchasing electricity and process steam. The supposed benefits of nuclear power are then evaluated in terms of these factors to ascertain to what extent nuclear power's benefits are meaningful to end users. The knowledge and the insights gained from this task will form the basis of the plan for marketing the output of the plant, a key element in the formation of a successful business case. This information is also used in other parts of the Study to evaluate: potential sites for the new plant; the available plant designs being offered by reactor suppliers; and different plant operating strategies.

Task 1 consisted of interviewing the end user companies to determine the factors impacting them in making their energy purchases. At the very outset of the study, the Study Team worked with several end user companies to determine their needs and requirements. In the parlance of Six Sigma, a methodology that is used extensively throughout this study, the Study Team determined end user CTQ's[1] and their ranking. This information was used in a variety of ways, including sorting through different options (ownership arrangements, for example), in order to make specific recommendations.

The purpose of determining the end user CTQs was to ascertain key factors that a Board of Directors can use to evaluate a proposal brought forth from the CEO to either 1) Finance a long term power purchase agreement, or 2) Make an equity investment in new plant construction.

The reason for establishing these critical decision factors at the outset was to ensure that the study was focused on developing a set of recommendations that would be found persuasive by the ultimate decision makers.

To the extent possible, the Study Team met directly with senior representatives of end user TIACT member companies in order to elicit their CTQs and factor rankings. Mr. Redding, who is a trained Six Sigma professional, facilitated these discussions.

1 *Items that are "critical-to-quality" of the product purchased by the end user. In this case, the product is the electricity, steam, and process heat from a nuclear plant.

1.2. PRINCIPAL FINDINGS

Discussions with TIACT members and other end users were fruitful and instructive. A central finding is that both the CTQs and their associated metrics were validated as well as the statistical evaluation of several power options. A brief description of the process used to carry out these evaluations follow. First, there being no knowledge of the CTQs, they were postulated by the researchers and validated by one-hour “focus group” meetings with 13 end users and ranked on the basis of 0 to 10. The average of these rankings for each CTQ is shown as a Weight Factor in Table 1B-3. Next the end users scored each of several electrical supply options for each CTQ on the basis of 0 to 100, as shown in the successive columns of Table 1B-3. The TOTAL by column is simply the weighted sum of the scores (raw score multiplied by the weight factor) and these totals are then normalized with respect to the highest total.

Several key results follow from Table 1B-3. These results are that the key pieces of information form the foundation on which to build the business case, evaluate technologies, and develop appropriate schedules for a new plant project. All of this information will be used in turn in discussing the potential project with investors. A second major finding is that the statistical evaluation of the nuclear option stacked up well against other options.

Table 1B-3 (Appendix). Statistical Evaluation of the Electricity Supply Options

ELECTRICITY OPTIONS CTQs	Weight Factors	Retail Electricity Provider	Co-generation (CHP)	Nuclear PPA at 10% below market	Partial ownership of nuclear plant if ROIC is 15%
Low Cost	9.3	57	57	76	2
Cost Stability	8.0	46	34	42	2
Few service interruptions	7.1	66	57	51	1
High Power Quality	6.2	51	45	43	1
Flexibility to meet load profile	6.1	51	34	39	1
Less usage of natural gas	10.0	21	11	51	2
Predictable start of supply	4.7	36	21	21	1
Supplier portfolio	5.9	44	16	27	1
Air emission offsets	3.3	2	7	19	0
TOTALS*		1.00	0.76	0.99	0.03
STANDARD DEVIATION		25%	72%	39%	223%

* Normalized relative to the highest score of the different options.

Finally, the discussion with end users and the analysis of the data have led to valuable insights. These insights have resulted in the outline of a plan to market the output of the plant through a portfolio of Power Purchase Agreements to various categories of end users. The results, which are summarized below in Tables 1.3 and 1.4, will strengthen the business case by identifying credible revenue sources for the project.

1.3. METHODOLOGY: USING SIX SIGMA TO DETERMINE END USER REQUIREMENTS

Six Sigma methodologies are used to determine and quantify the end users' requirements. In the parlance of Six Sigma, end user requirements are referred to as "CTQs" and are those features that, in the mind of the customer and not the supplier, are "critical-to-quality" of the product or service purchased. For purposes of this Study, the CTQs are those factors that end users take into account when making a decision to buy electricity or process steam or both.

The Six Sigma approach was chosen because this methodology emphasizes

- Being systematic
- Focusing on what is important to the user of the product or service
- Using metrics instead of generalized statements
- Requiring that the information be validated by end users

For example, an important CTQ when purchasing electricity is, not surprisingly, "we need low cost electricity." This statement, however, is not nearly as useful as "we need electricity costs to be 4.0 cents per kWh (kilowatt hour) in order to be competitive."

1.4. WHAT ARE THE CTQs?

End users will purchase the output of a new nuclear plant to meet the energy needs of their businesses by entering into a Power Purchase Agreement (PPA) with the owners of the plant or by choosing to invest in the plant itself and capturing the output at cost. Either way, someone in the organization will bring a proposal to the CFO, the CEO and the Board Directors (that is, those individuals who "own" the decision) for approval. The CTQs that were developed by the Study team were intended to be the factors that these individuals would consider to be important in arriving at their decision. The CTQs that were developed for discussion with end users are given in Table 1.1.

Table 1.1. CTQs or End User Requirements

1. Low cost
2. Cost stability
3. Few service interruptions
4. High power quality
5. Flexibility to meet load profile
6. Less usage of natural gas
7. Predictable start of supply
8. Supplier portfolio strength or creditworthiness
9. Air emission offsets
10. Other–write in

At this point, the Study Team did not assign either a weight factor or a metric. That was the purpose of the end user surveys.

The survey was an opportunity to have direct conversations with senior energy managers for purposes of:

- Validating their CTQs
- Determine the relative importance or Weight factor of each CTQ
- Evaluating several different ways of procuring energy, including that generated by a nuclear power plant
- Developing a metric for each CTQ so that there is a quantitative and consistent way of evaluating each of these supply options.

Appendix 1A contains a brief description of six sigma methodology, how each option is scored for purposes of ranking them.

1.5. WHO ARE THE END USERS?

In early April, the Study team developed a set of CTQs for discussion with end users. The Study team next conducted one-hour meetings with senior energy managers of twelve TIACT member companies and the City of Mesquite.[2] The first of these meetings took place on April 8th and the last one concluded on May 18th.

The end users consist primarily of petrochemical plants, specialty chemical plants, refineries, and those in support industries that supply products such as hydrogen, oxygen, and nitrogen. Manufacturers can be characterized as follows:

- Chemical Plants with Batch Processes – These plants use natural gas to produce steam. Since they were not large enough to justify cogeneration, they purchased the electricity as needed.
- Chemical Plants with Large Continuous Processes – Natural Gas a Major Feedstock.

In these plants, cogeneration units using natural gas produce the steam and electricity. Plant managers buy (or sell) incremental amounts of electricity from the grid, according to the demands of their operation. The major feedstocks for these plants are natural gas and other hydrocarbons.

- Chemical Plants with Continuous Processes – Petroleum Condensate is the Major Feedstock. These plants produce most of their natural gas and other feedstock needs by cracking hydrocarbon condensate. The natural gas produced by this process is used to produce steam and electricity. Additional gas is purchased as needed. Any excess electricity produced is sold to the grid.

For the businesses surveyed, energy costs typically average 25% of the operating budget. Because the chemical producers are doing business in a globally competitive market, there is limited

2 Mesquite is an incorporated city near Dallas that purchases its electricity through the Public Power Pool, and entity that procures electricity on behalf of many Counties and Cities within Texas.

opportunity to recover higher energy costs from customers by way of price increases so a great deal of importance is attached to energy procurement and management.

The peak electrical load of these end users averages about 210 MW (megawatts.) However, it may be more useful to note that end user loads falls within two clusters, the first of which is between 20 and 75 MW, the other being between 150 and 250 MW. (There is one facility that qualifies as a statistical “outlier”[3] because its 1200 MW load is very much out of the ordinary. By way of commentary, that one facility could consume the entire output of a modern-day Advanced Nuclear Plant.) Almost all of the end users surveyed have flat load profiles with load factors between 85% and 90%. These are ideal customers for marketers with access to nuclear-generated base load power.

All but one member company surveyed does business in the ERCOT[4] control area, where deregulation has reached both the wholesale and retail level. The market in ERCOT is robust, which means that there is significant competition for their energy business. Managers report that, when procuring energy, it is not uncommon for them to receive up to six bids. As evidence that the retail market is thriving, consider that 60% of the industrial load has switched suppliers. Similarly, 42% of the commercial and 15% of the residential loads have switched energy service providers.[5]

Because burning natural gas generates 73% of all electricity in Texas, the price of electricity in ERCOT tracks that of natural gas. The going price for large industrial consumers of electricity is between $45 and $55 per MWh (megawatt hour) as delivered. Current tariffs for delivery, which include primarily charges for transmission, distribution, and system benefits, are typically around $5 per MWh for a customer with a peak load of 200 MW.[6] Thus the energy component of electricity is between $40 and $50 per MWh. The comparable number for smaller (non-manufacturing) end users is about $10 per MWh higher.

Over half of the end users surveyed have cogeneration facilities, primarily to ensure reliability in the supply of both electricity and steam. An equally important consideration is that gas-fired cogeneration facilities use Combustion Turbines that generate process steam at the high temperatures and pressures needed for chemical manufacturing processes. Using resistive heating (substituting electricity for natural gas) to make process steam at these conditions would be prohibitively expensive even at today’s elevated price levels for natural gas. We will look at the prospects for nuclear cogeneration in Task 3, Technology Assessments.

3 A statistical term that refers to a data point that is many standard deviations from the mean.

4 The Electric Reliability Council of Texas, http://www.ercot.com .

5 March 2004 Report Card on Retail Competition, Report of the 78th Legislature on the Scope of Competition in Electric Markets www.puc.state.tx.us/electric/projects/25645/rptcrd/mar04rptcrd.pdf.

6 Tariffs for all of the regulated Transmission and Distribution Suppliers transmissions providers can be found at www.puc.com .

Table 1.2. At a Glance…

Petrochemical Manufacturers	ERCOT
• Average electrical load is 210 MWs. • Need uninterruptible supplies of both process steam and electricity • A sizeable majority rely upon gas fired co-generation • Natural gas is a raw material in many of the processes • Energy costs are on average 25% of operating costs. • Have a different risk profile than power companies.	• 70,000 MW of generating capacity • 73% of all generation is gas fired • Deregulation down to the retail level • 60% of industrial load has switched energy service providers. • On the Gulf Coast, Houston, Galveston, and Freeport have been designated non-attainment areas. • So are counties surrounding Fort Worth and Dallas. San Antonio exceeds the limits but is in a deferred status.

1.6. TASK RESULTS: AND THE SURVEY SAYS...

The results of the meetings with the survey participants are presented in the tables found in Appendix 1A-2, including a table of CTQs that end users validated as being important.

1.6.1. Low Cost

By far the most important CTQ was low cost coming in with a score of 9.3 (out of 10). These responses also exhibited the least variability with a standard deviation of 1.1. It couldn't be clearer that the end users need low cost electricity supplies.

Only a few end users indicated that "low cost" to them meant a certain price level, such as $30 or $40 per MWh. This is somewhat surprising since the chemical industry competes in a global market without much freedom to raise prices. It does suggest therefore that they have some ability to offset increases in electricity costs with cost reductions in other areas. The more frequent response was that low cost meant 10% less than the prevailing market price for electricity. This suggests that marketers of nuclear electricity will have to offer power on this basis; that is, the contract price will float with the market. This point will be revisited at the end of this Task 1 report where some ideas for developing an effective marketing plan for the output of the plant are discussed.

1.6.2. Few Service Interruptions

Service interruptions and cost stability were the next most important factors, scoring 8.0 and 7.1 respectively. These showed a bit more variability. For many end users the need for minimal service interruptions ranks near the top and in some cases is considered to be a more important factor than low cost. There are a number of reasons for this, including:

- Loss of Product – Unfinished product falls out of spec during the interruption and must be thrown away.
- Extended Down Time – The use of digital control systems that require lengthy recalibration after an interruption is prevalent and growing.

- Potential Environmental Impacts – These must be managed.

With very few exceptions, the metric for service interruptions is stringent, ranging between 1 in 5 years (0.2 per year) to zero interruptions per year. Currently, the Texas grid is highly reliable and meets these pretty tough standards. Moreover, there are alternative suppliers, a healthy spot market, and a Provider of Last Resort (POLR) to ensure continuity of supply in the event one's energy supplier is unable to make contractual deliveries. This could change, but it does mitigate the risk associated with depending upon a single nuclear plant for electricity supplies.

1.6.3. Cost Stability

The results with respect to cost stability provided more surprises. Although some end users are quite willing to enter into long-term agreements of 15 years or more[7], most are comfortable with just a 1 or 2-year agreement. This reflects the belief by procurement managers that electricity prices will decline. A contract longer than a year or two exposes them to the risk that prices will come down and leave them at a competitive disadvantage. What is surprising is that this view persists despite the mounting evidence that natural gas prices will remain above the $4 per MBtu (million British Thermal units) level, well above the prices experienced during the 1990s.

Those who have entered into the long-term contracts (15 years or more) are those who have made a commitment to buy the output of a major cogeneration facility, a fact that should hearten nuclear generators/marketers.

It is somewhat surprising that the volatility of both natural gas and electricity prices has not motivated buyers to lock in prices in order to fix these costs in their budgets. It is, however, understandable when one recognizes the risk profile of procurement managers is such that they have a preference for finding opportunities to lower costs even at the expense of long term cost stability. They are, in other words, unwilling to pay a premium for stability and rely instead upon their own considerable skills to hedge the risk.

1.6.4. Flexibility to Meet Load Profile

End users are able to take of advantage of their flat load profiles and save money by purchasing power in blocks. If the need for electricity is greater than what the block provides or if the need is less, then end users "top and trim" their load. The issue here is how much it costs to top and trim load.

A decided advantage of being located in ERCOT is that the retail market is very competitive and offers up a variety of products and services that allow customers to top and trim in a variety of ways, including the purchasing of power in spot markets. As a result, not much importance is attached to a supply contract that allows end users the flexibility to top and trim without undue cost and this is reflected in a relatively low Weight factor of 6.1. For a metric, we use a number from 1 to 5, where a value of 1 means no flexibility is acceptable and 5 means the end user would gladly pay a cost

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7 In May 2004, DOW Chemical entered into a 25-year agreement with Calpine for the supply of electricity and process steam. Source: Wall Street Journal, May 28, 2004, "Calpine Signs 25-year Pact with Dow Chemical".

premium for supply flexibility. The average value for all end users is 2.00 with the majority of responses being 1.0 indicating, obviously, there is ample flexibility outside the supply contract to increase or decrease electricity supplies.

This is of significance to a nuclear generator/marketer because a nuclear plant does not follow load and it is possible that the ownership of the nuclear plant will not have other generating assets to provide the flexibility that end users demand. This, however, is not an issue for end users in today's ERCOT market.

1.6.5. Predictable Start of Supply

Another factor of significance to nuclear generators/marketers is the start of supply. As is the case with all generators who are marketing the output of a newly constructed power plant, there is some risk that the start of commercial operation will slip due to delays in licensing or construction. To the extent that the plant's output is sold in advance through Power Purchase Agreements, this becomes a problem for end users.

The risks of licensing and construction delays are obviously higher for a nuclear plant, at least for the first round of new construction. However, this does not appear to be of much concern to end users who give it a Weight factor of only 4.7 and are willing to accept a delay of almost a year. End users in ERCOT, as mentioned before, have ready alternatives should they receive word that the start of supply will not be as promised. They would hedge their risk also by stipulating in the Power Purchase Agreement that they be compensated for costs associated with the delay.

1.6.6. High Power Quality

End users have deployed an ever-increasing number of digital control systems, which have strict voltage tolerances. Though not as strict as those found in Silicon Valley manufacturing facilities, these design tolerances will result in the shutdown of control systems and processes for very small fluctuations (on the order of half a volt for a cycle or two.) Thus, we asked end users about the importance of voltage stability because nuclear plants can provide significant amounts of voltage support; and they can cause perturbations in the local grid if tripped offline unexpectedly. One company reported that an unexpected outage at an existing nuclear plant resulted in the frequency falling to 59.7 Hertz. A similar incident occurred on the Western grid on June 14th. A transmission line failed in Arizona, then a substation relay malfunctioned, and then the three Palo Verde nuclear plants tripped offline (due to loss of offsite power.) System frequency fell to 59.498 Hz and a total of 4,100 MWs of generation quickly went down. The results were felt in Northern California as many manufacturers reported severe voltage drops (which was brought to everyone's attention when the computer screens blew out.)

End users surveyed give power quality a ranking of 6.2, somewhat in the middle of the pack. However, there was some variability in the results with some giving power quality a ranking of 10, reflecting a greater use of digital controls. We created a metric that reflects the use of digital controls in this way: a value of 1 (on a scale of 1 to 5) means that the grid's power quality is acceptable; a value of 3 means that the end users facility is characterized by the use of digital controls; and a value of 5 means "high nines" power quality is needed. The acceptable value, averaged over the end users surveyed, is 2.58. This, of course, reflects the widespread use of digital controls but also reflects the fact that in most locations the power quality on the grid is quite good at present.

We believe the importance of power quality will only grow in time and that a well-run nuclear plant (with zero forced outages, as many operating plants are experiencing) can provide very important voltage support (reactive power) and frequency control. Historically, generators have been unable to translate this into a meaningful revenue source (in the Ancillary Services Market, for example.) A recommended follow-up action is to engage the grid operator in a discussion of this topic.

1.6.7. Supplier Portfolio and Creditworthiness

In the aftermath of the Enron scandal, in which they suffered financial losses when Enron and other energy service providers were unable to fulfill contractual commitments, end users have an understandable concern regarding the dependability and financial viability of their energy supplier. The importance of this issue to end users varies but averages a 5.9 ranking. The metric for this concern is creditworthiness or alternatively the size of the supplier's physical generating capacity in MWs compared to its delivery commitments. We combined these two into a metric that expresses a supplier's dependability on a scale of 1 to 5. The level of dependability that end users are seeking, on the average, is 3.8. This suggests that the marketer of nuclear electricity should have backup resources or excellent financial backing. A stand-alone, project-financed entity would likely fail this test.

1.6.8. Less Usage of Natural Gas

This brings us to the only remaining CTQ and the one that precipitated this study—the cost of natural gas. All end users placed a high value (10s) on decreasing the use of natural gas to generate electricity. They are, however, unable to decrease their own use of natural gas. As has been well documented, natural gas is an important feedstock in the production of basic commodity chemicals such as ethylene and polyethylene and end users advise us that for this purpose there is no equivalent alternative. Thus, decreasing the use of natural gas is not explicitly taken into account in decisions to procure energy.

To effectively address this issue, we created a CTQ that addresses the benefits that accrue to chemical manufacturers indirectly. This CTQ can be stated as follows:

1.6.9. "Decrease my natural gas prices as much as possible as soon as possible."

Based upon the interviews, we attach a Weight factor of 10 to this CTQ.

This CTQ as stated is vague, of course. To create a useful metric, we quantify the CTQ statement in this way:

- Decrease natural gas used to generate electricity in Texas by 10%, that is, from today's level of 73% to 63%. How much this will actually lower natural gas prices depends upon the many factors that make up supply and demand.

- Impact natural gas consumption between Jan.1, 2005 and Jan. 1, 2010.

This utility of this statement is that it suggests actionable items.

A full 10% reduction in the use of natural gas for generating electricity is represented by a value of 5 whereas a value of 0 means no reduction at all. Likewise, any decrease in natural gas consumption in the generation sector that begins in 2005 is represented by a value of 5 whereas a value of 0 means no impact before 2010. To use an example:

- Natural gas consumption decreases by 4%…value of 2
- Decrease is as of 2009…value of 1

To get a single metric, we simply average the two.

So what is an acceptable metric for end users? Since most supply contracts are one to two years in length, an acceptable time frame for some movement away from gas would be two years from the date of the surveys, or about Jan. 1, 2006. A minimum 5% reduction in gas consumption in the generation sector is needed to affect prices significantly. The combined metric for end users is, then, the average of 4 (time aspect) and 2.5 (consumption decrease) or 3.75, toward the high end of the scale.

To review, we have to this point:

- Validated the CTQs through direct discussion with end users
- Developed Weight factors to understand the relative importance of each CTQ in the decision to procure energy
- Created a metric for each of the CTQs
- Gained important insights for the generator/marketer of electricity from a new nuclear plant.

1.7. DISCUSSION: EVALUATING THE ELECTRICITY SUPPLY OPTIONS

The next step then is to evaluate the supply options available to end users. Because ERCOT is fully deregulated, the options available to end users are more varied than for consumers in other parts of the U.S.

1.7.1. Description of the Supply Options

The first of these is to buy electricity from one of the many Energy Service Providers, which in Texas are referred to as REPs (or Retail Energy Providers). A REP buys wholesale electricity and the delivery service; schedules the load with the grid operator; provides other related services such as ancillary services; prices electricity for customers; and seeks customers to buy electricity at retail. The ERCOT market is characterized by the presence of many buyers and many sellers and transparent prices, the very definition of a functional market.

The next option is cogeneration to produce both electricity and process steam (thus it sometimes goes by the name of CHP or Combined Heat and Power.) A cogeneration unit is located either on the customer's site or adjacent to it. It is either owned by the end user or by an independent generator such as Calpine who builds, owns and operates the power plant for purposes of selling steam and electricity to the end user under a long term contract (15 years or more.) In some cases, excess electricity is sold into the market.

Finally, we introduced two new options, which are to buy the output of a nuclear plant either via a Power Purchase Agreement or to make an investment in the plant for purposes of capturing the electricity at cost. The "buy nuclear" option was described to those surveyed as follows:

- Electricity would be priced at 10% below the prevailing market rate.
- The supplier would be willing to lock in this price formula for 15 years or, alternatively, guarantee the price at a fixed amount (in cents per kWh.)

The "invest in nuclear" option is similar to that employed by the Finnish utility TVO (Teollisuuden Voima Oy) which owns 2 nuclear plants and is building a third. TVO is owned primarily by several large paper makers (a process that is electricity intensive) and the utility Fortum that buys and retails about 25% of the plant's output. The end users capture the electricity at cost and any excess electricity is sold into the deregulated market. In our surveys, we described ownership as meaning that the end user has an equity position of 10% (or less), takes 10% of the plant's electricity, and is billed only for its share of ongoing costs such as fuel and plant operations. The net savings would provide an expected return on invested capital of at least 15%.

1.7.2. Results

The results of evaluating each of these four options against the CTQs are found from the TOTALS in Table 1B-3 in the Appendix 1B. These are summarized below:

Option	Normalized Rankings
• Buy from a Retail Electricity Provider	1.00
• Buy electricity from or own a cogeneration unit	0.76
• Buy from a nuclear generator	0.84 to 1.99[8]
• Own a partial share of a nuclear plant	0.03

1.7.3. Discussion: Buy from a REP (Retail Energy Provider)

The highest-ranked option is to simply purchase electricity from a REP. All end users, even if they rely upon cogeneration, recognize this as a highly workable option. End users report receiving up to 6 competitive bids from which to choose. This is an indication that ERCOT is having success with deregulation. The presence of a robust retail market is confirmed by high scores for service interruptions (the grid is very dependable and the large pool of dependable suppliers ensures continuity of supply) and by flexibility to meet varying load requirements through spot market

8 For an explanation of this range of results, please refer to Tables 1B-3 and 1B-4 in the Appendix.

purchases or sales.

Despite its overall desirability, this option does not do well in satisfying the most important CTQ[9], the need for low cost electricity. This obviously reflects the significant increase in the cost of natural gas, the consequences of which are now being felt by end users in the way of higher electricity prices. This is the cloud that hangs over this option. Currently, 73% of all generation in Texas is from natural gas fired plants and there are no concrete plans as of yet to diversify the mix, other than to increase the amount of renewables (which will not do much to alleviate the upward pressure on electricity prices).

It does do well in meeting customers' need for cost stability, the next most important CTQ. The reason is that the majority of end users surveyed are not interested in long-term contracts that they feel may lock in high prices. They prefer instead to be on the lookout for opportunities to lower cost and hedge the financial risk, something they are quite adept at doing. Thus a 1 or 2-year contract, which is readily available in the market, provides as much stability as they want. This is a somewhat surprising result given the recent volatility of natural gas prices and probably reflects optimism among procurement managers that prices will come down. To be sure, there are those who are interested in long-term contracts of 15 years or more, but some if not most of those contracts stipulate that the price will float with the cost of gas or some other index. A reasonable conclusion to draw is that when energy managers are sophisticated, as those we surveyed are, there is not a strong need for the safety and comfort that others may seek in long-term commitments. This has implications for nuclear generators, as we shall see.

1.7.4. Discussion: Cogeneration

Many chemical processes require steam at high temperatures and pressures. Because these processes are continuous, and because a loss of process steam can result in lost product and downtime worth millions of dollars, it is critically important that the source of process steam be highly reliable and basically uninterruptible. For these reasons, there is widespread use of cogeneration. In fact, over 50% of those surveyed do so. Combustion turbines are well suited for this purpose because the high outlet temperatures can produce the steam needed and still have enough heat left over to make electricity the old-fashioned way.

While those who have cogeneration are very high on this option, overall among the group of customers surveyed the option was ranked 20% lower. This ranking held true across all CTQs except that of cost, where it scores 10% higher than for simply purchasing electricity. As we know, the use of cogeneration eliminates transmission costs, which is worth $5 MWh or about 10% of the total cost. Moreover, end users can capture the full value of the high efficiency of combined cycle units by using 60% of the energy to make steam and electricity. There is a limitation on the potential use of steam generated by a nuclear reactor because of the distance required between the nuclear reactor and the process.

9 Other than the need to reduce the usage of natural gas, which ranked so high in every case it is taken almost as a given.

1.7.5. Discussion: Buy Nuclear Electricity

Buying electricity from a nuclear generator scores well with end users, provided there is sufficient incentive to entice them to leave their current suppliers. For example, when asked to evaluate nuclear electricity if they could buy it at the prevailing market price, end users gave this option a ranking of 0.89. When the option was recast so that cost of nuclear electricity is 10% less than the prevailing market price[10], the overall ranking jumped to 0.99. In a head to head comparison of the CTQ “low cost”, the buy-nuclear option ranks 33% higher than Option 1 (buy from a REP). At least end users are behaving rationally!

Another obvious conclusion is that it is important to offer nuclear electricity at a discount relative to market prices to entice customers to switch to a new and untested supplier. And indeed there are some less-desirable aspects associated with a nuclear generator that need to be overcome through lower prices or some other benefit. The CTQs for which nuclear electricity did poorly and really stand out as issues are:

- Predictable Start of Supply 42% less than Option 1
- Creditworthiness of the Supplier 39% less than Option 1

The first of these is unique to the nuclear option because it is perceived that there are significant uncertainties in the licensing and construction schedules. This risk can be hedged, of course. End users indicated that they would require a provision in the supply contract that would obligate the nuclear generator to provide some form of compensation should electricity not be delivered on the specified date. This would likely be a payment representing the difference between the contract price and the spot market price.

Thus it is important that the nuclear generator be creditworthy (or have backup generating assets or both) so that the customer has assurances that he will be made whole should there be any hiccups. Of course, the creditworthiness of generators and energy service providers has taken on heightened importance in the aftermath of the Enron debacle. Many customers were caused significant financial harm by their supplier’s lack of performance and were unable to collect damages.

Two other areas that need to be mentioned are:

- Minimal Service Interruptions 23% less than Option 1
- High Power Quality 16% less than Option 1

The CTQ Minimal Service Interruptions refers to both grid reliability and to continuity of supply by the nuclear generator. The ERCOT grid is quite reliable, so the conclusion to be drawn is that there is a concern that the nuclear plant will not be reliable, either because of faulty technology or poor management. Such unreliability of an individual plant will tend to create disturbances on the grid,

10 We do not want to leave the impression that 10% is the minimum discount needed for nuclear electricity to be successfully marketed. Rather, 10% was an arbitrary figure, used to stimulate conversation. Our opinion is that had we used 5% or 15%, then the response would have been basically the same.

ranging from blackouts to voltage and frequency drops. Although existing nuclear plants in Texas have performed quite well, some customers noted that because of their location on the grid, they have experienced disturbances when a nuclear plant unexpectedly dropped offline.

Also reflected here is a concern for lack of performance by the supplier, especially in the event of a prolonged shutdown.

Where the buy-nuclear electricity option really shines in the minds of customers is, as an alternative to generating electricity with natural gas. As has been noted earlier, 73% of the electricity generated in Texas is from plants using natural gas. The same holds true across the nation. The Energy Information Administration reports that increased natural gas consumption, which has been considerable, is attributable almost entirely to its use in producing electricity.[11] Combined with a decline in natural gas production, this has led to the price increases that have severely impacted chemical manufacturers. It is no wonder, therefore, that when it comes to the CTQ related to using less natural gas, end users rank the nuclear option nearly 150% higher.

There were several interesting discussions concerning air emission credits, which in Texas are referred to as Emission Reduction Credits (ERCs). The major population areas including Houston, Galveston, Freeport, Dallas-Fort Worth and San Antonio's (which is in a deferred status) are in non-attainment zones. In these areas, ERCs are required for new major emission sources, or for sources undergoing major expansions, by the state's air management agency.[12] Thus, chemical manufacturers who wish to expand production or locate new facilities in the region must obtain ERCs to the extent that their processes emit nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM), and reactive organic gases (ROG). There is a market for ERCs but it is thin and prices, especially those forecasted for the next several years, are quite high.

Since the cost and availability of ERCs are major impediments to expansion, chemical manufacturers must decide if Texas is a good place to invest in plant additions or new plants. For elected officials and other policy makers, it is an issue that needs to be addressed in order to maintain a hospitable business climate.

Several end uses therefore were very interested in the capability of a nuclear plant to provide offset credits, either directly (along with the electricity) or to the market, which helped to boost the overall ranking of nuclear electricity by a few points. Of course, legislation would be needed to enable the owner of new nuclear plants to sell ERCs, but this is certainly within the realm of possibility, especially since one state, Vermont, has already taken that step.

11 The Energy Information Administration has figures on its website, one of which is http://www.oilcrisis.com/gas/eia/images/consumptionbysector200101.gif .

12 The Texas Commission on Environmental Quality has jurisdiction.

1.7.6. Discussion: Invest in Nuclear Electricity

A few end users indicated that their companies would give serious consideration to owning a partial share of a new nuclear plant if certain conditions were met. One of these conditions is to capture the electricity at its production cost (fuel and O&M costs.) Since the average production cost for U.S. nuclear plants is currently 1.8 cents per kWh (around 1.2 cents for the best performing plants), this is quite attractive compared to 5 cent, which seems to be the going rate for industrial customers in Texas. However, the cash flow that is freed up from this savings must be enough to earn them a 15% Return on invested capital (ROIC.) These responses were counted in the scoring.

A few more companies indicated that their companies were supportive of nuclear power in general and therefore might conceivably take an ownership interest in a new plant. These responses were not considered strong enough to count in the scoring.

Thus, this option received a poor overall ranking. This should not obscure the fact that there are end users with significant load and extensive corporate financial resources who are willing to look at the possibility once the details are known.

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An Important Point to Remember
In order to initiate the construction of a new nuclear plant in Texas, the active support of chemical manufacturers is needed in a number of ways.

The first of these is to agree to purchase the electrical output of the plant. The owners of the new plant would be delighted if this were to take the form of a PPA (Power Purchase Agreement). End users, on the other hand, need some extra incentive to do so. As the discussion of the CTQ related to natural gas reveals, a strong consideration for end users will be if the nuclear plant to which they are making a commitment via the PPA has a timely and substantial impact on natural gas prices. The same is true if end users are to have a partial ownership of the plant. In other words, this might be the extra incentive needed.

The active support of end users is also needed in the area of public policy, specifically to make modifications to create conditions favorable to nuclear energy (fairly so.) With the backing of end users, for example, Texas might allow nuclear owners to sell air offset credits in the market, as has been done in Vermont.

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1.8. MARKETING THE ELECTRICAL OUTPUT OF A NUCLEAR PLANT

The first step in building a successful business case for a new power plant of any kind is to demonstrate a credible source of revenues. This is particularly important for a privately financed power plant that does not have access to an assured revenue stream, as would be the case if the plant were subject to regulation.

Thus the first use of the CTQ results is to guide us in developing a credible plan for marketing the electrical output of the nuclear plant. What have we learned so far?

First, the cost of electricity needs to be competitive. According to the metric, this means some percentage, say, 10% of the number that we used in the survey, below the prevailing market price. Today, that figure is about $50 per MWh. That means in order to successfully market the electricity the price needs to be around $45 per MWh.[13]

Secondly, we know that there are customers who are interested in 1-2 year deals and others who are willing to sign longer-term contracts of 15 years or more. We also know that some end users are fearful of locking in prices and are looking for a formula price, for example, 10% off the prevailing market price, as defined in the supply contract. Others are willing to take advantage of a fixed price at some cents per kWh. The nuclear generator should have some of each in its portfolio. The beginnings of a properly diversified portfolio for a 1200 MW plant would include those elements in Table 1.3.

Table 1.3. Building the Portfolio Structure for the Marketing Plan

Amount	Length of Supply	Pricing	Purpose
Chemical Manufacturers			
100 MW	1-2 years	Fixed	Steady, predictable income stream. Protects the revenue stream when short-term prices are expected to be flat or turn down. Can be reconfigured if prices start to move up.
100 MW	1-2 years	Variable	Upside opportunity to take advantage of greater “headroom” (the difference between the market price and production costs) if prices increase in the market.
200 MW	15,20,25 years	Fixed	Predictable long-term income stream, enough to ensure debt coverage.
200 MW	Ownership	Cost	Take the electricity at its production cost.

Commitments by end users to purchase power from the nuclear plant, if made in advance of the project starting, would be extremely valuable for purposes of securing the construction loans. The CTQs provide guidance on how to go about getting those commitments. End users are willing to commit in advance of the project so long as they can be assured that supply will actually begin within 12-24 months of the contract delivery date and provided that they are compensated for any financial losses they incur by purchasing replacement power from another source. The supplier must be creditworthy.

Thus, even though it is desirable to use project financing, it may be necessary to instead use some form of corporate financing to satisfy customers’ needs to have a reputable and financially sound counter party. It also suggests that owners make use of hedging techniques (financial options or real generating resources) to ensure delivery of electricity at the agreed-upon price in the event

13 We will be forecasting the short and long-term price of electricity for the ERCOT markets in a later chapter.

commercial operation is delayed. Finally, it is very important to manage the licensing risk (e.g., government-backed loan guarantees) and to have contracts with the builder of the plant containing both incentives and liquidated damages to provide greater assurance that the construction schedule will be met. All of this can be done well enough in advance of the project to support an early contract commitment between the nuclear generator and customers. A strategy for doing so will be discussed in a subsequent chapter, when we discuss a strategy for proceeding to the next step.

Finally, we now know that the size of the market is somewhat limited by the widespread use of gas-fired cogeneration plants, which end users have deployed primarily to meet their needs for process steam. Electrical heating and therefore nuclear-generated electricity, is not a feasible replacement for these purposes. (The topic of nuclear cogeneration will be taken up in the next section.) Since the readily available nuclear plant designs have output ratings between 1200 and 1400 MW, the marketing plan will need to encompass consumers outside the industrial sector.

This realization prompted us to extend the survey to include an incorporated city; the Public Power Pool that purchases electricity on behalf of many cities and counties; City of San Antonio Public Service, a municipal utility; and the Brazos River Authority, which is a large consumer of electricity.[14]

14 The Brazos River Authority has purchased Allen's Creek Reservoir near Houston for purposes of constructing a water storage lake. The permit to build the lake was originally issued to Houston Lighting and Power (Reliant Energy) in 1974 by the Texas Natural Resource Conservation Commission (TNRCC). It is an intriguing irony that the reservoir was originally permitted as a cooling lake for a nuclear power plant. When Reliant Energy abandoned plans to construct the nuclear power plant at the Allen's Creek site in the 1980's, the property purchased by the City of Houston and The Brazos River Authority. The new reservoir will provide fresh water to meet the future needs of the City of Houston and surrounding communities but significant amounts of electricity will be needed to convert the brackish water to usable form.

Table 1.4. Portfolio Structure for the Marketing Plan

Amount	Length of Supply	Pricing	Purpose
Chemical Manufacturers—600 MW			
100 MW	1-2years	Fixed	Steady, predictable income stream. Protects the revenue stream if short-term prices are expected to be flat or turn down. Can be reconfigured if prices start to move up.
100MW	1-2 years	Variable	Upside opportunity to take advantage of greater "headroom" (the difference between the market price and production costs) if there are price increases in the market.
200 MW	15,20,25 years	Fixed	Predictable long-term income stream, enough to ensure debt coverage.
200MW	Ownership	At Cost	Anchor tenants.
Public Agencies—500 MW			
100 MW	1-2 years	Fixed	Public Power Pool—diversity.
300 MW	Ownership	At cost	Municipal utility—anchor tenants
100 MW	15,20,25 years	Fixed	Brazos River Authority—predictable long-term income stream.
Spot Markets—100 MW			
100MW	Real time, hour ahead, day ahead	MCP[15]	Mildly speculative with lots of upside potential.

1.9. NUCLEAR COGENERATION

Of all the end users surveyed, over 50% rely upon cogeneration units to provide process steam and electricity (or CHP, combined heat and power.) More striking, these account for 85% of the load represented in the survey. Quite clearly cogeneration is an important option.

Those that use cogeneration have chemical processes that require process steam at specific temperatures and pressures. Some typical ranges for these processes are:

- Very high pressure 1500 psi
- High pressure 400 to 600 psi
- Medium pressure 100 to 300 psi
- Low pressure 30 to 45 psi

Combustion turbines are particularly suited for these purposes because turbine exit temperatures are 2200 degrees F. This is hot enough to produce saturated steam at any of the desired pressures. Combustion turbines used for cogeneration are also highly efficient, as high as 80%.

15 Market Clearing Price as determined by the cost of the last bid needed to clear the market in the real time, hour ahead and day-ahead markets. In tight markets, the MCP will be set by peaking units for which the bid price will normally be high. In these circumstances, the upside potential can be large especially for a base load plant with low production costs.

This high efficiency, the relatively clean nature of natural gas combustion, and control technologies that further reduce emissions make these plants easier to site, especially in non-attainment areas. It is no wonder that cogeneration has found widespread use in the Houston ship channel.

We discussed CTQs and metrics with some of the end users employing cogeneration. Because these discussions were not as rigorous or as complete as the survey on electrical usage, the results don't lend themselves to statistical analysis.[16] However, we did gain several important insights.

The first is an obvious one. Cogeneration units by definition are located on or adjacent to the user's site. This eliminates the need for transmission services, which cost about $5 per MWh, or 10% of the total cost of delivered electricity. They also provide protection against future rate increases. In Texas, there are projects underway to relieve congestion within the various transmission zones, such as the South Zone and the Houston Zone, and the cost of these projects is spread among all customers using delivery service. Moreover, ERCOT is moving to Locational Marginal Pricing (LMP) that introduces uncertainty in what future delivery rates will be. This is because the purpose of LMP is to increase transmission costs to encourage the siting of new generation where it will alleviate congestion.

End users also informed us that an important advantage of cogeneration is reliability, particularly with respect to steam used in continuous manufacturing processes.[17] To ensure this reliability, end users build an extra unit that can be called upon quickly should another unit experience a forced outage. Thus, cogeneration capacity is modular in nature, meaning it is added in smaller increments. For example, one end user whose load is 50 MWs, has two units rated at 35 MWs and is adding a third unit of the same size for reliability purposes.

Another worthwhile insight is that resistive, i.e. electrical, heating to generate process steam is not a feasible alternative because of the costs. For one thing, manufacturers have sizeable sunk costs associated with producing process steam with gas-fired boilers. Secondly, switching to resistive heating would require major changes to the facility. Finally, resistive heating to generate high pressure steam is less efficient. One end user surveyed suggested that the indifference point between continuing to use high price natural gas and switching to resistive heat is a cost of electricity equal to 1.3 cents per kWh, roughly equal to the production cost of nuclear electricity. We judge the prospects of making process steam by substituting nuclear electricity for gas-fired boilers to be small. It is safe to say that the petrochemical manufacturing facilities were designed and built on the premise of cheap natural gas.

So what about nuclear cogeneration? Clearly there is a market for it but that market will have the following characteristics that the currently available reactor designs (those with Design Certifications) would have difficulty meeting:

16 The CTQs and their relative importance (weighting factors) associated with procuring CHP are very similar to those of procuring electricity only. One difference, however, is that the emphasis on service interruption is higher for process steam.

17 Loss of process steam especially when the manufacturing process is continuous in nature has significant financial consequences in the way of lost product and downtime that amounts to $10M or more per event.

- Outlet temperatures sufficient to generate steam at pressures above 400 psi.
- Ratings of between 200 and 600 MW
- Can be sited on or adjacent to chemical facility located near a major population center

The ideal nuclear cogenerator can be visualized in this way: dismantle the existing gas fired units and replace them with a nuclear cogenerator and the customer sees no difference in the operation of his manufacturing processes.

There are nuclear plant designs under development that have the potential to meet these needs and will be discussed in the chapter on technology assessment.

1.10. ENHANCING THE BUSINESS CASE: THE NEED FOR HYDROGEN

In order to develop as compelling a business case as possible, the use of the nuclear plant's output to produce hydrogen is being explored. This use practically suggested itself since hydrogen is widely used in the petrochemical industry and a good network of hydrogen pipelines is available for distribution. The statistics are that the U.S. demand for hydrogen currently is about 9 million tons per year of which about 1.5 million tons is merchant hydrogen production that is sold to refineries and chemical plants.[18]

About 95 percent of U.S. hydrogen production for supplemental refinery needs (to remove sulfur from heavy oils) and for the chemical industry is produced from natural gas using steam-reforming technology.[19] There are two undesirable characteristics associated with making hydrogen in this manner—the cost is tied directly to prices of natural gas, clearly a very stressed resource, and the hydrogen produced contains some impurities.

Electrolysis, on the other hand, has the advantage of producing pure hydrogen without the need for natural gas. Several end users, especially those in the air products business, expressed interest in finding an alternative source of hydrogen, particularly pure hydrogen, because it commands a price premium in the marketplace. The disadvantage is that electrolysis until now has been the more expensive option. The rule of thumb is that natural gas needs to be in the $5 to $6 per MBtu range in order for electrolysis to be competitive. Clearly that day has arrived.

We will be exploring the technology and economics of hydrogen-producing technologies in Task 3. For now, what we have learned from discussing the issue with end users is:

- There is a sizeable market for merchant hydrogen.
- The time is right for finding a less costly replacement for generating hydrogen than with natural gas.
- Producing pure hydrogen can yield higher revenues.
- The electricity produced by a nuclear plant in off-peak hours may have more value if it were

18 Source is the U.S. Department of Energy http://www.fe.doe.gov/programs/fuels/hydrogen/currenttechnology.shtml .

19 Ibid.

used to generate hydrogen.

- For the owners of the plant to capture this value, they would need to own an electrolysis unit (or some other technology) located near a hydrogen pipeline and sell themselves the electricity.

1.11. ENHANCING THE BUSINESS CASE: THE NEED FOR FRESH WATER

Using nuclear power for desalination has found some limited use throughout the world, notably Japan, and the International Atomic Energy Agency is fostering research in this area since much of the world's population needs greater access to potable water.

Finding new supplies of fresh water is an emerging issue for Texas and most of the Western states. It is not, however, an issue at this time for the chemical industry since their operations have not been constrained by lack of fresh water. They certainly recognize this as an important regional issue but look to the appropriate authorities to manage the problem.

One of those regional authorities is the Brazos River Authority, an agency of the State of Texas that supplies water to 37 counties. Except for occasional governmental grants to help pay the costs of specific projects, the Authority is entirely self-supporting from the revenues it produces from sales of water to distributors.

The Brazos River Authority has expressed significant interest in the possibility of dedicating some of the electricity produced by a nuclear power plant to converting brackish water and salt water into potable water.

1.12. SUMMARY AND NEXT STEPS

Discussions with TIACT members and other end users were both fruitful and instructive. One key result was the validation of their CTQs and associated metrics. These key pieces of information are the foundation on which to build the business case, evaluate technologies, and develop appropriate schedules for a new plant project. All of this, in turn, will be used in discussing the potential project with investors.

Analysis of the data collected by the survey has led to valuable insights. These insights helped us to outline a plan to market the output of the plant through a portfolio of Power Purchase Agreements to various categories of end users. A marketing plan will strengthen the business case by identifying credible revenue sources for the project.

TASK 2

ASSESS POTENTIAL SITES

TASK 2. ASSESS POTENTIAL SITES

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TASK 2. ASSESS POTENTIAL SITES

2.1. INTRODUCTION

The purpose of Task 2 is to ascertain if there exists a site (or sites) that could potentially host a new nuclear plant and the extent of the effort (including time and cost) required to permit the preferred site. It is helpful to view this purpose within the context of the overall purpose of this study, which is to determine the feasibility of building a new nuclear plant to serve the needs of end users on the Texas Gulf Coast and to create a roadmap that will provide steps (actionable items) that can be taken in that direction.

There are two existing nuclear sites in Texas, each of which is an obvious candidate for one or two more nuclear units. Existing sites have potentially significant advantages, including enough land to accommodate additional units within the Exclusion Zone, access to transmission lines or right of ways, adequate heat sinks, and socioeconomic suitability.

Task 2 has two specific work activities, the first of which is to evaluate these and other characteristics of the site to confirm that these advantages are real. The second and equally important purpose is to determine that there are no new regulations, information or conditions that would rule out these existing sites.

It is important to note that this evaluation and the supporting information are not to the same level of detail that would be required for an Early Site Permit application. It is more equivalent to the screening effort that takes place prior to the decision to proceed with an Early Site Permit (ESP) application for the highest ranked site of all those considered.

2.2. PRINCIPAL FINDINGS

The sites of the two existing nuclear plants in Texas, Comanche Peak and South Texas Project, would make good hosts for additional nuclear units. This conclusion is based upon a high level screening analysis that used 10 evaluation criteria. This evaluation did not uncover any issues that would disqualify either site from further consideration. Indeed, the characteristics of each site were found to be highly favorable or favorable in all respects.

The numerical results of this evaluation are given in Table 2.1 below. Although the numbers indicate a slightly higher score for South Texas Project, this should not be taken as definitive or that a preference exists. Indeed, we believe that other considerations, such as the interest of the site owner for participation in a new plant project, will dictate which of these sites or yet another greenfield site will be selected. That selection process lies in the future.

Table 2.1. Site Assessment

Site Evaluation Criteria	Weight Factor	Comanche Peak	South Texas Project
Seismic Evaluation	0.70	5	5
Permitting/Licensing Status	0.72	5	5
Water Availability	0.35	5	5
Demographic Changes	0.61	5	5
Exclusion Area	0.65	5	5
Emergency Planning	0.75	3	5
Transmission Access	0.74	Not scored	Not scored
Power pricing	0.93	1	2
Plans for Existing Units	0.40	5	5
Spent Fuel Storage	0.76	5	5
TOTAL (29.35 possible)		24.33	26.56

In addition, these sites were found to be superior sites in terms of environmental suitability. This determination was reached by assessing the sites against a set of environmental criteria from the EPRI guide that were deemed to be the most significant. These criteria fairly depict (in more detail than the previous set of criteria) the environmentally suitability of each site. The results are given in the table below.

Table 2.2. Selected Environmental Criteria

Environmental Suitability Criteria	Comanche Peak	South Texas Project
Population	5.0	5.0
Emergency Planning	5.0	5.0
Atmospheric Dispersion	5.0	5.0
Proximity to Consumptive Users	4.5	4.5
Groundwater Radionuclide Pathway	4.0	5.0
Atmospheric Dispersion - Operational Effects	4.5	5.0
Surface Water - Food Radionuclide Pathway	3.5	4.0
Disruption of Important Species/Habitats and Wetlands-Construction Related	4.0	4.0
Wetlands	5.0	5.0
Migratory Species Effects	5.0	5.0
Disruption of Important Species/Habitats--Operational	5.0	5.0
Total (55 possible)	50.5	52.5

2.3. METHODOLOGY

The methodology used in this study follows that of the “EPRI Siting Guide.” This refers the EPRI (Electric Power Research Institute) document entitled“Siting Guide Site Selection and Evaluation Criteria for an Early Site Permit Application”, EPRI Technical Report 1006878, March 2002. This is the industry standard for site selection and ESP (Early Site Permit) preparation. It is used here by permission of the Electric Power Research Institute. TIACT and EnergyPath are very grateful to EPRI for their close cooperation and for its support of this study and its purpose.

The Siting Guide recommends use of a four-step approach when selecting a site for use in an Early Site Permit application and presumably a Combined Construction and Operating License (COL) if site licensing is included the application. The purpose of Step 1 is to identify potential sites that exist in the Region of Interest, which in this case is Texas, and to begin the process of weeding out undesirable sites by use of “exclusionary” and “avoidance” criteria. The result is a list of candidate sites. The screening continues in Step 2 where exclusionary and avoidance criteria more local and therefore more specific in nature are used to reduce the number of candidate sites to a manageable few.

As stated in the Siting Guide, the objective of Step 3 is “to identify and rank a relatively small number of candidate sites (from the list of potential sites) for a more detailed study.” The purpose of Step 4 is “to select a preferred site from candidate sites identified in Step 3.”[1]

The objectives of Step 3 are very similar to those of Task 2 of this Study. Within the Region of Interest, Texas, three sites have been identified as candidate sites

- Comanche Peak
- South Texas Project
- Blue Hills

The first two are, of course, the sites of operating nuclear units, a de-facto measure that these sites would pass the Step 1 and 2 screens.

Blue Hills was the intended site of two nuclear units for which the NRC (Nuclear Regulatory Commission) licensing review process had been initiated but obviously not completed. The siting characteristics of Blue Hills were also evaluated more recently in the context of the Early Site Permit Program. Again, these facts are taken as a de-facto measures that Blue Hills would pass the Steps 1 and 2 screens.

2.3.1. Evaluating the Sites Using Suitability Criteria

Ranking of the three sites is done by using a number of “suitability” criteria that taken together characterize the site in terms of four broad issues: health and safety, environmental impact, socio-economics, and engineering and costs.

These criteria, it will be noted, are in fact statements of issues that need to be considered in the ranking of sites. They lack specificity and each therefore must be represented by a proxy measure or what the Siting Guide calls a utility function. These are for the most part provided by the Siting Guide. In the few instances where there is not one, a simple utility function can be created using the suggestions found in the Siting Guide.

2.3.2. Narrowing the List of Candidate Sites

At some point in the future when a decision is made to move forward with an actual project, it will be necessary to apply to the NRC for a site license.[2] This application must meet the NEPA (National Environmental Policy Act)requirement that alternative sites be considered. Although not required for this study, there is value in documenting that alternatives were considered.

For this purpose, the EPRI Guide provides guidance. It states that the NRC “has noted that a full-scale, systematic siting process may not be necessary to justify selection of an existing site for an ESP. For example, guidance provided to NRC staff on their review of alternative site analyses (NUREG-1555, Section 9.3, III (8)) states, in part (emphasis added):

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1 Page 2-5 of the Siting Guide.

2 In the form of an Early Site Permit or a Combined Construction and Operating License.

> "*Recognize that there will be special cases in which the proposed site was not selected on the basis of a systematic site-selection process.* Examples include facilities proposed to be constructed on the site of an existing nuclear power facility previously found acceptable on the basis of a NEPA review and/or demonstrated to be environmentally satisfactory on the basis of operating experience…"

The reason is that "existing nuclear power facility sites have previously been reviewed by NRC and found to satisfy the principle that no obviously superior site existed at the time of original licensing."[3]

The significance of this guidance is that if the existing sites, Comanche Peak and STP, are shown by use of the criteria found in the Siting Guide to be "obviously superior" (environmentally speaking) it will not be necessary to consider alternative sites, including to the greenfield site, Blue Hills.

2.3.3. The Blue Hills Site

Although Blue Hills is a potentially acceptable site for a new nuclear plant, it lies outside the ERCOT control area[4]. A discussion with ERCOT's management (Director of Transmission Services) in early September 2004 confirmed that there is currently no capability to import power from this site into the ERCOT system and hence to the loads of the petrochemical industry on the Texas Gulf Coast. ERCOT is uniquely characterized by the lack of inter-tie connections with other control areas.

The inability to transmit power to end users without the need to invest significant amounts into the transmission systems makes the Blue Hills site economically undesirable. The study then will focus on reviewing the environmental suitability of the two existing sites.

2.4. SCOPE OF THE SITE EVALUATION

Since both sites were originally licensed ten to fifteen years ago, it is possible that the sites do not meet current regulations or that conditions around the sites (population growth, grid capacity, use of water, for example) have changed sufficiently to alter the presumptive conclusion that the sites are suitable. An evaluation is clearly needed but, as the Siting Guide states, the purpose is

"…to identify any potential negative impacts on the "apparent" suitability of the existing site, when judged against current standards and conditions."

2.4.1 Criteria to Use

A full evaluation of a site's suitability involves the use of 58 different criteria that cover a full range of applicable issues–health and safety, environment, socioeconomic, engineering and costs. To streamline the evaluation, as circumstances dictate and the Siting Guide suggests, 10 criteria that address "things that may have changed" will be used. These criteria are roughly grouped as shown

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[3] ibid, Section 4. 2.2, pages 4-5 and 4-6.

[4] The Blue Hills site is located near Beaumont Texas, near the Louisiana border and lies within the Southeast Electric Reliability Council (SERC).

Technical issues
- Seismic Evaluation
- Permitting/Licensing Status
- Water Availability

Community issues
- Demographic Changes
- Exclusion Area
- Emergency Planning

Related to Making the Business case
- Transmission Access
- Power Pricing
- Plans for Existing Units
- Spent Fuel Storage

A full explanation of what each criterion entails is found in the Siting Guide and cannot be reproduced here because of its proprietary nature.

These 10 criteria help flush out any fatal flaws that may exist in the technical elements of the project or in the business case for locating a new plant at these particular sites. The same is true for any "go/no-go" demographic changes that have made the site an inappropriate location for a new plant.

The Siting Guide does not assign a weight factor to any of these criteria, so they are listed above in no order of priority. However, we know that some of these criteria are more important than others, especially in terms of meeting the needs of both end users and the project's owners and investors.[5] So, in keeping with the Six Sigma approach that we use throughout this study, the Task 2 team, (including experts from Black & Veatch, Sandia National Lab, and augmented by siting experts from the nuclear industry) have scored the ten siting criteria above in terms of meeting these two sets of CTQs. These scores are then used as weight factors and are given in Table 2.3. In addition, we have developed a set of metrics for each of the ten criteria that are quite useful for a proper evaluation of the two candidate sites. The results are given in Table 2B-1 in the Appendix 2B. Not surprisingly, ready access to transmission capacity and the expected price of power–key aspects in the business case for a new plant--score high, appropriately so for this initial screen.

[5] Investor CTQs are introduced and discussed in detail in subsequent study tasks.

Table 2.3. Weight Factors for Siting Criteria as Derived from CTQs

SITE EVALUATION CRITERIA	Weight Factor
Seismic Evaluation	0.70
Permitting/Licensing Status	0.72
Water Availability	0.35
Demographic Changes	0.61
Exclusion Area	0.65
Emergency Planning	0.75
Transmission Access	0.74
Power Pricing	0.93
Plans for Existing Units	0.40
Spent Fuel Storage	0.76

2.4.2. Evaluating the Environmentally Suitability of the Two Sites

After reviewing the sites for commercial attractiveness and to ascertain the presence of significant challenges, the next step is to review each site against the criteria found in sections 3.1.2, 3.1.3, and 3.2 of the Siting Guide. These criteria provide an objective framework for evaluating and ranking the environmental suitability of existing nuclear power plant sites such as Comanche Peak and STP.

If one or both of these two proposed sites are shown to be highly suitable for all of the environmental criteria and/or if there are no criteria for which the sites are deemed highly unsuitable, it can be argued that no environmentally preferable site exists. Site comparisons beyond this stage may not be necessary. On the other hand, if the analysis shows that the proposed sites rank low in suitability for one or more environmental criteria, it will be so noted and recommended that alternative sites (such as Blue Hills) be evaluated[6] in future work.

2.5. GENERAL DESCRIPTION AND LOCATION OF THE CANDIDATE SITES

2.5.1 Comanche Peak

The Comanche Peak nuclear power plant is located in Somervell County site about 30 miles southwest of the nearest portion of Fort Worth and approximately 4.5 miles north-northwest of Glen

[6] For the applicable regulation, see NUREG-1555, Section 9.3 (1).

Rose, the nearest community. It is situated along Squaw Creek, a tributary of the Paluxy River that ultimately drains into the Brazos River. The adjacent Squaw Creek Lake is the source of cooling water for the two PWR units, each rated at 1150 MWs. Unit 1 entered commercial operation in 1990, unit 2 in 1993. The site area is approximately 7,700 acres. Photographs of the Comanche Peak and the South Texas Project Reactors are shown in Figure 2.1. The complete layout of the facilities at the South Texas Project is shown in Figure 2.2.

2.5.2 South Texas Project

The South Texas Project (STP) generating station is located in south-central Matagorda County west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. It consists of approximately a 12,200 acres of land and includes areas being used for a plant, a railroad, and a cooling reservoir. The site is located about 12 miles south-southwest of Bay City and about 13 miles east-northeast of Palacios between FM (farm-to-market road) 1095 and the Colorado River, which is the source of cooling water for the plant. Unit 1 entered commercial operation in 1988, Unit 2 one year later in 1989. Each is rated at 1250 MWe.

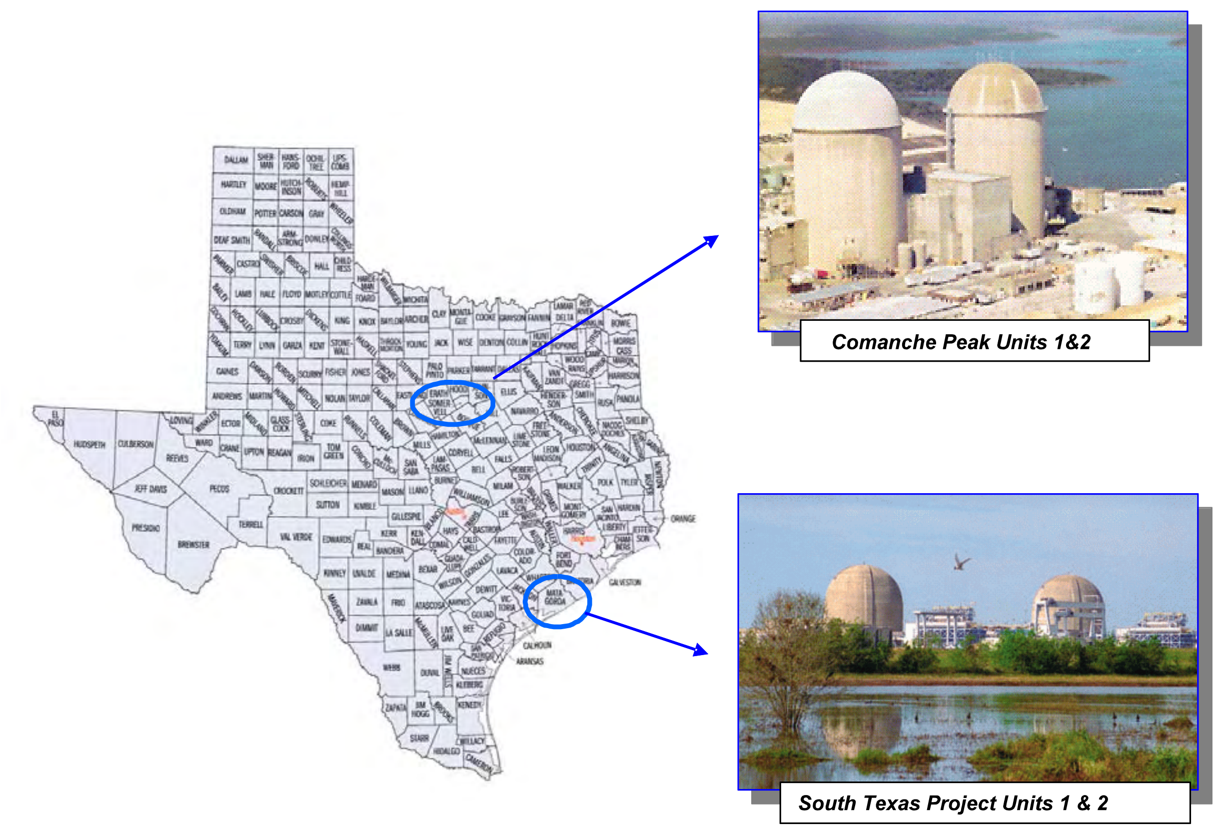

Figure 2.1. Comanche Peak Units 1 and 2 and South Texas Project Units 1 and 2.

Figure 2.2. Layout of Facilities at the South Texas Project

2.6. EVALUATING THE CANDIDATE SITES

2.6.1. Seismic

2.6.1.1. Why is This Important?

The NRC's recently revised seismic reactor site criteria in 10 CFR Part 100, Appendix A (Reference 5), and 10 CFR Part 50, Appendix S (Reference 3), benefit from experience gained in the application of the procedures and methods set forth in the current regulations, as well as incorporating the rapid advancements in the earth sciences and earthquake engineering. Although existing sites licensed 10 or 15 years ago are not required to meet the newly revised standards, they do give a measure of suitability for siting additional units. The purpose of this screen is to assess the suitability of siting a new unit at the existing two candidate sites, in the context of the new criteria.

2.6.1.2. What the Data Says.

Two candidate sites were selected for this study. They are located in the Texas, at existing operating nuclear plant sites.

Candidate Site A (Comanche Peak Steam Electric Station (SES)) is located on the Comanche plateau, a subdivision of the Central Texas section of the Great Plains physiographic province.

Gently dipping Lower Cretaceous limestone and sandstone directly underlie the site. The site is located near the center of one of the world's major seismologically and geologically stable continental interiors. During the 300 year historical period no large earthquake has been recorded within 200 miles of the site. During this same period, no large earthquake which cannot be attributed directly to geologic structures known earlier through ongoing seismicity has been documented within this stable continental interior. No earthquakes have been felt at the site since the beginning of site selection activities in the 1960s', or subsequent to commercial operation. In fact, there is much to suggest these original values for base ground acceleration may have been overly conservative and that designs based on the minimum of 0.10g required by 10 CFR Part 100, would be sufficiently conservative.

Candidate Site B (South Texas Project Electric Generating Station (EGS)) is located in the Gulf Coast portion of the Texas Gulf Plain Geosyncline. It is a low-lying, flat, featureless terrain composed primarily of river floodplain and littoral and deltaic sediments. The site is located on a surface of the Beaumont Formation, consisting of lenticular sands and clays. Two principal rivers, the Colorado and the Brazos, cross the Gulf Coast Plain and empty into the Gulf of Mexico. The Colorado River is immediately adjacent to the east side of the site. The soils beneath the Category I structures are safe against liquefaction during the postulated Safe Shutdown Earthquake (SSE). Acceleration/intensity correlations indicate an acceleration of 0.07g/0.035g for an earthquake of intensity VI/V modified Mercalli. However, the minimum ground acceleration in 10 CFR 100, is 0.10g/0.05g, and accordingly was adopted for the SSE/OBE, where (OBE) denotes Operating Basis Earthquake.. Regulatory Guide 1.165 identifies five parameters related to geology, seismology, and soil conditions that must be evaluated to determine the candidate site's suitability. These are:

- Vibratory Ground Motion (SSE / OBE)
- Capable Tectonic Structures or Sources (within 200 miles)
- Surface Faulting and Deformation (within five miles)
- Geologic Hazards (subsidence, seismic induced waves/floods)
- Soil Stability (liquifaction, slope stability)

Each of the candidate sites were reviewed against these criteria for a new unit, and compared against the results of the previous as-licensed analyses. The results are summarized here. The complete analyses is found in Appendix 2B (Seismic Evaluation.)

2.6.1.3. Evaluation

Both Candidate Sites are located in some of the most geologically stable regions of the U.S.. Historical and recent history (subsequent to existing unit Licensing) has demonstrated this stability. Although Candidate Site "B" has slightly less expected ground motion (and lack of liquefaction concerns), the incremental difference is insufficient to warrant different scores. The abundance of rock close to the surface at the Candidate Site "A" is initially very attractive, but may prove difficult to blast in close proximity to operating units. Therefore, both sites receive high scores (5, the highest) and are equally acceptable.

2.6.2. Permitting/Licensing Status

2.6.2.1. Why is This Important?

Any proposed new power plant, and especially any proposed new nuclear power plant, will be required to obtain numerous federal, state and local government permits and approvals. The procedures for obtaining many of these permits and approvals have provisions for extensive public participation and intervention. A proposal to locate a new nuclear power plant at an existing plant that has a history of significant regulatory non-compliance would likely be viewed, both by the public and by regulatory agencies, as a request for, “More of the same bad news.”

2.6.2.2. What is the Nature of This Criterion?

The assessment looks to ensure that the candidate sites do not carry this type of institutional risk that could affect approval of an Early Site Permit (ESP).

2.6.2.3. What the Data Says

Comanche Peak

Comanche Peak’s NRC Operating License Nos. NPF-87 and NPF-89 require implementation of an Environmental Protection Plan with annual reporting to the NRC. The most recent report was dated April 21, 2004[7] and covered the 2003 calendar year. During this period Comanche Peak reported one instance of a fire protection discharge to Squaw Creek Reservoir that was a technical violation of the plant’s Texas Pollutant Discharge Elimination System (TPDES) Permit. This discharge was reported to the Texas Council on Environmental Quality (TCEQ) and there was no subsequent enforcement action.

During a site visit, Comanche Peak personnel confirmed that the plant has no history of significant permit non-compliance and that there are no pending enforcement issues.

South Texas Project

TIACT requested information from the STP concerning status of permits, compliance and whether there have been any Notices of Violation (NOVs) or other enforcement actions from state or federal agencies. STP’s response[8] stated:

> “There are no outstanding or problematic ongoing regulatory issues involving the existing STP units. There is no history of regulatory concerns about discharges from the existing facility.”

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[7] Comanche Peak Steam Electric Station, Annual Environmental Operating Report for 2003, Docket Nos. 50-445 and 50-446, April 21, 2004.

[8] Letter STP to TIACT with attachment, October 4, 2004.

During a site visit, STP personnel confirmed that there are no pending enforcement issues.

2.6.2.4. Evaluation

In terms of permitting and licensing status, both sites receive high scores (5, the highest) and are equally acceptable.

2.6.3. Water Availability

2.6.3.1. Why is This Important?

Power plants that generate electricity via steam turbines, such as the proposed, Texas new nuclear plant, hereafter referred to for convenience as Texas Gulf Coast Nuclear Plant, require water for several different purposes. The primary requirement in terms of water quantity is for condensing steam in the condenser(s).[9] These cooling water requirements typically dwarf other power plant needs in terms of quantity. Therefore, this assessment of water availability assumes that if the cooling water requirement can be met at either of the candidate sites, then the other water requirements can also be met.

Assessment of water "availability" for a power plant involves several considerations. First, will sufficient water be physically present at the source on a consistent and reliable basis? In other words, will enough water be present to meet the power plant's needs even during periods of reasonably anticipated droughts? Secondly, can sufficient water rights be obtained to secure the legal use of the water against existing and potential future competing water users. Thirdly, what is required, from the engineering and operations perspectives, to deliver the water supply to the plant?

2.6.3.2. What is the Nature of This Criterion?

Table 2.4 summarizes the Siting Guide's estimated Cooling Water Requirements[10] for the Composite 1993 ALWR.[11] The numbers in Table 2.4 are in general agreement with an independent first order estimate of the proposed Texas Gulf Coast Nuclear plant's cooling water requirement. This estimate was made by scaling up by a factor of 20% the closed cycle system cooling water requirements of Ameren's 1,100 MW Callaway Plant located near Fulton, Missouri. The base load cooling water requirement for the Callaway Plant is 16,100 gpm. Scaling up, the Texas Gulf Coast

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9 This assessment assumes that air cooled condensers would not be acceptable for the proposed TIACT plant.

10 Siting Guide at § 3.1.1.2.1.

11 "In order to ensure that all available Advanced Light Water Reactor (ALWR) plant designs would be useable at the site under consideration, a fictional or "composite" design was created by using the most conservative design parameters of all plants. This bounding approach is similar to the Plant Parameter Envelope used in the Early Site Permit programs.

Nuclear closed cycle cooling water requirement[12] would be 19,320 gpm or about 31,165 acre-feet/year. This assessment addresses the availability of up to 35,000 acre-feet of water per year for use at the candidate sites and considers, to the extent that information is available, other potential constraints such as delivery of water to the sites.

Table 2.4. Estimated Cooling Water Requirements for Composite 1993 ALWR

Requirement	1993 ALWR Value (gallons per minute)	Acre-feet/year Equivalent*
Makeup Flow Rate (closed cycle system)	20,600	33,230
Maximum Consumption of Water (closed cycle system)	17,700	28,552
Monthly Average Raw Water Consumption (closed cycle system)	15,400	28,842
Cooling Water Flow Rate (once-through)	1,100,000	1,774,428

* acre-feet per year equivalent assumes gpm value, 24 hours per day, 365 days per year.

2.6.3.3. What the Data Says

Comanche Peak

The cooling water supply[13] for the existing Comanche Peak Plant originates at Lake Granbury on the Brazos River. Water is pumped from an intake structure on Lake Granbury to the Squaw Creek Reservoir (SCR) located on the Comanche Peak Plant site. SCR serves as a cooling lake for the Comanche Peak Plant. SCR has a limited contributing drainage area of about 65 square miles.

The Brazos River Authority (BRA) effectively controls surface water supplies in the region. Comanche Peak has a water supply contract with the BRA for up to 70,000 acre-feet per year to be supplied from either Lake Granbury or from the larger upstream Possum Kingdom Reservoir. The Comanche Peak Plant pumps water from Lake Granbury as needed to maintain the water level and water quality in SCR.

To maintain a proper balance of water quality in Lake Granbury and SCR, it is necessary that a

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[12] Current environmental permitting regulations strongly favor closed loop cooling water systems as opposed to once-through systems at steam electric generating plants. See, generally, Final Regulations Establishing Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, 69 FR 41575, and Regulations Establishing Requirements for Cooling Water Intake Structures at Phase I New Facilities, 69 FR 41575. Therefore, this assessment assumes that the proposed TIACT plant would use a closed loop cooling system with cooling towers rather than a once-through system.

[13] Unless otherwise noted, information on the existing Comanche Peak cooling water system is from Comanche Peak SES/Final Safety Analysis Report, February 2001.

portion of the water actually diverted to SCR be returned to Lake Granbury. During a critical drought it has been estimated that the net amount of water supplied from Lake Granbury (i.e., total amount diverted less amount returned) to the SCR to support the existing Comanche Peak Plant would range from 26,050 acre-feet per year to a maximum of 38,260 acre-feet per year.

The following information concerning water available for future contracts was obtained in interviews with BRA personnel.[14] BRA currently has in excess of 50,000 acre-feet per year available for future contracts. Additionally in 2004 BRA filed an application with the Texas Council on Environmental Quality (TCEQ) to approve and additional 420,000 acre-feet per year of future supply with the majority of this supply originating upstream of Lake Granbury.

BRA does not currently have a method for “reserving” future water supplies. The authority is currently conducting a pricing study that may allow such reserves in the future. The pricing study is expected to be completed by the summer of 2005. BRA currently charges $47.75 per acre-foot per year for water under contract.

BRA contracts with industries and municipalities are typically for 50-year terms. BRA ensures the availability of contracted water during periods of droughts through its operation of reservoirs throughout the basin.

The most straight-forward method for delivering water from Lake Granbury to the Texas Gulf Coast Nuclear unit at the Comanche Peak Plant would be to use the existing Comanche Peak intake structure and pipeline to SCR. The Texas Gulf Coast Nuclear plant could then pump its portion of the water from the SCR. The pipeline connecting Lake Granbury to SCR is 48-inches in diameter and has a firm design delivery capacity of 61.5 million gallons per day (95 cfs). The intake structure has 4 pumps each with a capacity of 21.7 million gallons per day (33.5 cfs). Note that the existing 61.5 million gallons per day firm capacity could only deliver about 69,000 acre-feet per year to SCR. Although the Comanche Peak Plant normally uses less than its contracted 70,000 acre-feet per year from Lake Granbury, it will be necessary to increase the capacity of the existing intake structure and pipeline to supply both Comanche Peak and the proposed Texas Gulf Coast Nuclear plant.

South Texas Project

The cooling water supply for STP is pumped from the Colorado River into the Main Cooling Reservoir (MCR) located on the plant site. The Colorado River intake structure is located near river mile 14. Tidal effects extend further upriver to about river mile 22 on the Colorado River.[15] Increased salinity associated with the tidal effects, as well as certain low flow conditions in the river limit the times and amounts that the STP can pump from the Colorado River to the MCR. The MCR is constructed above grade and thus does not have its own contributing drainage area.

Two permits principally control the STP’s existing diversion of water from the Colorado River and

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14 Telephone interview with Mike McClendon, BRA.

15 STPEGS FSAR at 2.4-45

the use of water in the MCR. Contractual Permit No. 327 from the TCEQ authorizes use of 102,000 acre-feet of water per year from the Colorado River for industrial purposes. This permit is based in part on the STP's underlying contract with the Lower Colorado River Authority (LCRA). The maximum permitted rate of diversion is 1,200 cfs (539,000 gpm). Certificate of Adjudication No. 14-5437 authorizes the impoundment of 202,000 acre-feet in the MCR and the consumptive use of 80,125 acre-feet per year. This certificate limits pumping from the MCR to 8,087 cfs (3,639,150 gpm). STP's diversion from the Colorado River is further limited to not more than 55% of any flow in the Colorado River above 300 cfs.

The STP has an Operating Procedure[16] for the Reservoir Makeup Pumping Facility to ensure compliance with the above permits and to limit the pumping of saline water associated with tidal effects. Pumping is never to occur when water conductivity exceeds 2,100 uS/cm unless the MCR level decreases to a point that pumping is administratively controlled by a guideline for water management during drought conditions. The pumping schedule, based on flow in the Colorado River is shown in Table 2.5. This schedule indicates a maximum pumping rate of 600 cfs (269,280 gpm) which is only half of the maximum permitted Colorado River diversion rate of 1,200 cfs (539,000 gpm).

Table 2.5. Pumping Schedule for Existing STP Colorado River Intake Structure

River Flow at Bay City Gauge Station (cfs)	Maximum Allowed Pumping Rate (efs)	Pump Combination	
		60 cfs Pump	240 cfs Pump
410	60	1	0
519	120	2	0
737	240	0	1
846	300	1	1
955	360	2	1
1173	480	0	2
1282	540	1	2
1391	600	2	2
Source: STPNGS, Reservoir Makeup Pumping Facility, 0POP02-LM-0001, Rev. 22, October 26, 2004.			

The Texas Commission on Environmental Quality (TCEQ) effectively controls the availability of future surface water rights in the STP region. LCRA has acquired rights to most of the available but unused water rights in the basin but several permit applications are pending. LCRA contracts with municipalities, industries, irrigators and residential users for water to be diverted from the Lower Colorado River Basin. The following information on water available for future contracts was

16 STPNGS, Reservoir Makeup Pumping Facility, 0POP02-LM-0001, Rev. 22, October 26, 2004.

obtained in interviews with LCRA personnel.[17] LCRA currently has 48,000 acre-feet per year available for contract to all future uses in the Bay City area. Additionally, the LCRA Board has reserved an extra 50,000 acre-feet per year exclusively for future municipal and industrial uses. Thus, a total of 98,000 acre-feet per year are available for future contracts.

The Texas Gulf Coast Nuclear project could “reserve” its requirement, currently roughly estimated at up to 35,000 acre-feet per year, by entering a contract and paying LCRA $57.50[18] per acre-foot per year ($2,012,500 per year for 35,000 acre-feet per year) up until the time that the project actually begins to use water. Thereafter, Texas Gulf Coast Nuclear would pay $115 per acre-foot actually used and could elect to pay $57.50 per acre-foot per year of water contracted for but not used.

LCRA contracts with industries and municipalities are typically for 40-year terms whereas contracts with residential users are for 3-year terms. LCRA ensures the availability of contracted water during periods of droughts through its operation of reservoirs throughout the basin. In times of water shortage (i.e. less water available than needed to satisfy all water rights), LCRA contract industrial supplies are secure against other users in two ways. First LCRA’s water rights, on which its contracts are based, are superior to others in the basin and date to 1901. Secondly, as among those with contracts with LCRA, municipal and industrial users are superior to other users such as irrigators and residential users.

The most straight forward method for delivering water from the Colorado River to the Texas Gulf Coast Nuclear site at the STP would be to use the existing STP Colorado River intake structure and pipeline to the STP MCR. The Texas Gulf Coast Nuclear plant could then pump its portion of the water from the STP MCR. As noted above, the maximum pumping rate listed in STP’s Intake Structure Operating Manual (600 cfs) is only half of the maximum permitted diversion rate (1,200 cfs). Thus one alternative for delivering the additional Texas Gulf Coast Nuclear water would be to increase the existing maximum pumping capacity. Another alternative would be to keep the capacity the same but to increase the pumping duration.

2.6.3.4. Evaluation

In terms of water availability, both sites receive high scores (5, the highest) because there is reasonable assurance that a firm water supply of 35,000 acre-feet per year can be obtained.

2.6.4. Demographic Changes

2.6.4.1. Why is This Important?

The purpose of this screen is to ascertain if the growth and distribution of the surrounding population has changed significantly since the site was originally permitted. If such changes have occurred to the point of non-compliance with NRC regulation, it would add a significant complication

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17 Telephone interviews with Anissa Menefee, LCRA.

18 These costs are based on rates effective January 1, 2005 and rates may be increased over time.

to (but would not preclude) plans for locating an additional unit at this site. Although regulatory compliance for existing facilities would not be affected, there is the possibility that such a finding might raise questions about the existing units with some members of the public.

2.6.4.2. What is the nature of This Criterion?

The NRC requirement[19] stipulates that:

- The population density of the 20-mile area surrounding the plant be no more than 500 people per square mile.
- There be no community whose population exceeds 25,000 within the area determined by a circle whose radius is 1 and 1/3 times that of the LPZ. As shown in Figure 2.3.

2.6.4.3. What the Data Says

Sandia National Laboratory, using the data from the 2000 U.S. Census, prepared tables that showed the distribution population in surrounding areas out to a radius of 50 miles. Information obtained from the Texas Data Center corroborated this data, as expected.

The results, which are found in Table 2.6, indicate that the NRC requirements for population are easily met at any time in the future through 2050 and likely beyond. In both cases, the nearest community with a population greater than 25,000 is 50 miles in distance from the site and the average population density in the LPZ is and will remain well below 100 people per square mile.

2.6.4.4. Evaluation

In terms of demographics, both sites receive high scores (5, the highest) and are equally acceptable.

[19] Regulatory Guide 4.7 Appendix A, Item A.4.

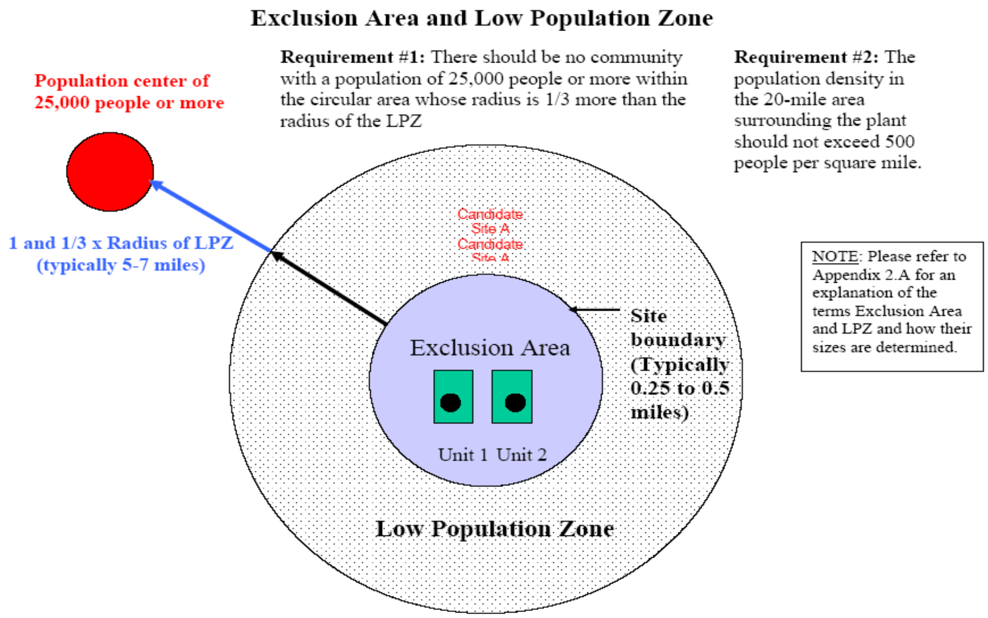

Figure 2.3. Exclusion Area and Low Population Zone

Table 2.6. Distribution of the Population in the Areas Surrounding Plant Sites

Information	Requirement	South Texas Project	Comanche Peak
General location		12 mi. SS W of Bay City	40 mi SW of Ft. Worth
Exclusion Area (radius in miles)		0.89 minimum	0.96 minimum
Low Population Zone (radius in miles)		3.00	4.03
Miles to the boundary of the nearest community with population exceeding 25,000 people	20	50 (Galveston)	50 (Ft. Worth)
Projected increase by 2050	20	50 No change except to Galveston population	50 No change except to Ft. Worth population
Average population in the 20-mile area surrounding the plant (per square mile)	500	28	44
Projected average by 2050	500	37	69

2.6.5. Exclusion Area

2.6.5.1. Why is This Important?

If there is not enough space to accommodate the new plant within the existing Exclusion Area (EA), then either more land must be purchased in order to expand the EA or this site must be ruled out.

2.6.5.2. What the Data Says

Figures 2.3 and Table 2.6 illustrate the existing plant property boundaries and the exclusion areas for the existing units. The new units can be sited such that the existing plant property will bound the exclusion area for the new units. The new exclusion areas are shown as semi-circle extensions to the existing exclusion circles. No additional land acquisition is required.

This conclusion is supported by the conceptual site layout of two representative Advanced Nuclear Plants done by John Manual of Black & Veatch (B&V). There are two plot plans per site and these are given in Appendix 2H. Please note that only one new unit is located on the site. In the case of Comanche Peak, it appears that there is not sufficient space for a second unit. For STP, there appears to be ample space for a second unit.

These plot plans are based upon publicly available information on the site layouts found in the Safety Analysis Reports of each plant and from publicly available information on the layout of the advanced nuclear designs.

2.6.5.3. Evaluation

Each site can accommodate an additional unit without acquiring land to expand the site boundary. That is also true of two units at STP and one unit at Comanche Peak.

2.6.6. Emergency Planning

2.6.6.1. Why is This Important?

To facilitate a preplanned strategy for protective actions during an emergency, there are two emergency planning zones (EPZs) around each nuclear power plant. The first is the Plume Exposure Pathway EPZ, a circular area around the reactor with a 10-mile radius. The other is the Ingestion Exposure Pathway EPZ, a wider circle around the reactor with a radius of 50-miles. The EPZs for South Texas Project are presented in Figure 2.3. More information on EPZs can be found in the section entitled “Basic Siting Terms” of Appendix 2A.

Nuclear power facilities are required to perform emergency response exercises at specific intervals: every year for the United States Nuclear Regulatory Commission and every two years for the Federal Emergency Management Agency (FEMA). The offsite response exercise requires the cooperation of local agencies (elected officials, police, fire, etc.) and the acceptance of local residents. It is possible that the addition of new units will strain the nature of this cooperation, particularly if significant changes in the Emergency Plans are needed, thereby creating a public relations issue for the existing units as well as the new ones. However, in many cases, nuclear plant emergency planning activities have provided significant aid in the development of local emergency response capabilities useful for non-nuclear emergencies (e.g., hurricanes, fires, floods).

2.6.6.2. What the Data Says

An integral part of the NRC's oversight process is to evaluate and grade each operating unit on a regular basis. This is done using performance indicators that measure reactor safety, radiation safety and safeguards.

There are three indicators for Emergency Preparedness: Drill/Exercise Performance, ERO (Emergency Response Operation) Drill Participation and Alert and Notification System. The designs of the new nuclear plants have additional safety features that reduce both the likelihood and the consequences of reactor accidents. Both contribute to a significant reduction in the potential for the offsite release of radiation. Moreover, the population density within the 10 mile EPZ for both plants is very low and is not expected, as discussed earlier, to change for the foreseeable future. Thus, the potential exposure represented by the new units to the surrounding population is the same or less than that posed by the existing two units. This information is easily accessible at the NRC's website.

We use these indicators as one measure of the effectiveness of the Emergency Planning. The other measure will be the extent of cooperation of local authorities in the offsite planning and drills. Taken together, these two measures will help us assess the reception that a new unit(s) will have within the community.

Comanche Peak

For both units 1 and 2, the three performance indicators for emergency preparedness are all "green" which is the color code for the highest grade available. In addition, local authorities have cooperated with state and federal agencies responsible for conducting emergency response exercises. The following is taken from the website of The Texas Department of State Health Services:

"In 2001, Radiation Control participated in an exercise evaluated by the Federal Emergency Management Agency. In addition to personnel from Radiation Control, the exercise included emergency response officials and personnel from the Texas Department of Public Safety, Hood and Somervell Counties, and the cities of Glen Rose and Granbury. Eighteen specific exercise objectives were demonstrated and no deficiencies or weaknesses were identified by the evaluation team. The exercise was conducted to evaluate our ability to respond to a simulated accident involving the nuclear power facility at Comanche Peak. Some of the key objectives demonstrated during the exercise were:

- Mobilization of Emergency Personnel
- Command and Control
- Emergency Worker Exposure Control

- Field Radiation Monitoring
- Protective Action Decision Making
- Alert and Notification to the Public
- Public Instructions and Emergency Information

In 1999, a comprehensive exercise was held to test response to a simulated reactor accident at Comanche Peak. The exercise involved several state agencies and the local governments for both Hood and Somervell Counties. The Federal Emergency Management Agency (FEMA) evaluated the exercise and found no deficiencies or areas requiring corrective action."[20]

South Texas Project

The indicators for these two units are also green. In addition, publicly available information indicates that an exercise in response to a simulated reactor emergency was conducted in 2004. This exercise was conducted by the Texas Department of State Health Service (DSHS) and involved various state agencies, Matagorda County, Bay City and Palacios. The FEMA report dated 11/15/04 found no deficiencies in the response and identified no areas that required corrective action.

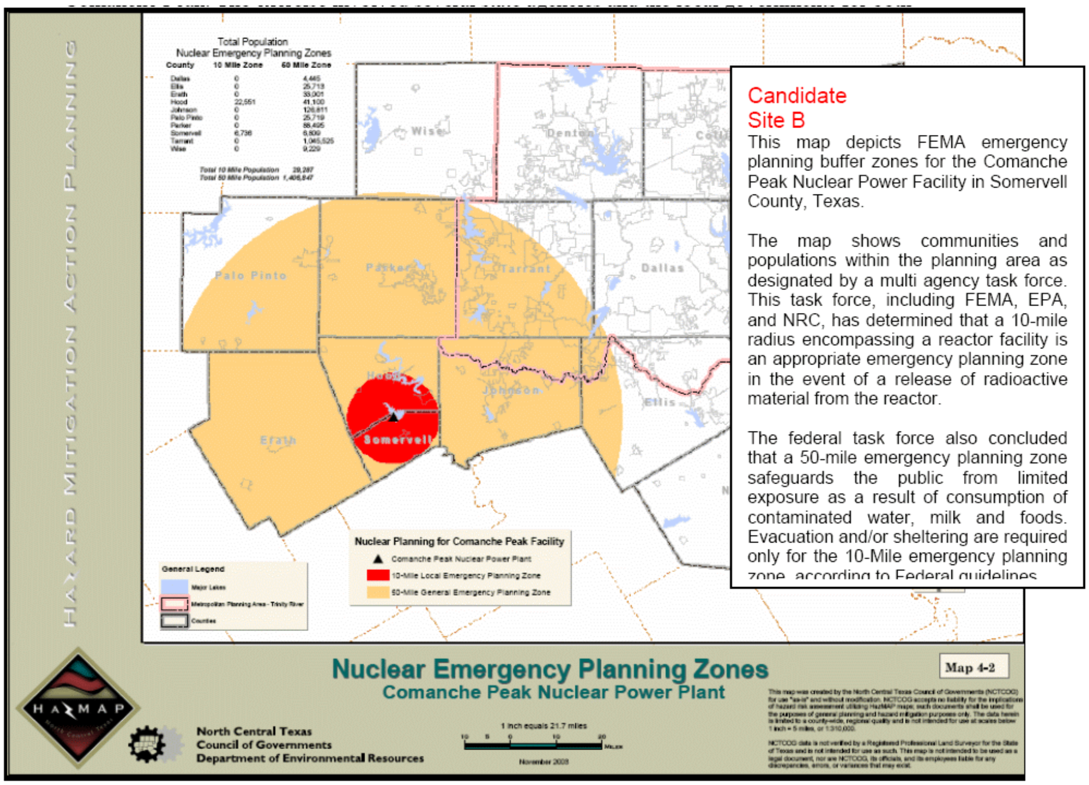

Figure 2.4. FEMA Emergency Planning Buffer Zones for the Comanche Peak Nuclear Power Facility

20 http://www.tdh.state.tx.us/radiation/comanche.htm .

2.6.6.3. Evaluation

Taking into account the safety features of the new designs and the low population density of the surrounding communities, we concluded that the potential for offsite radiation exposure to the public would not increase should new units be built at either site. There would therefore be no reason to change existing Emergency Plans. Nor do we expect that local authorities to resist such changes even if needed, given there past cooperation and the success of recent emergency response exercises. **Both sites score extremely well (5, the highest.)**

2.6.7. Transmission Access

2.6.7.1. Why is This Important?

The construction of a new nuclear plant must be accompanied by an increase in transmission capacity either by the construction of a high voltage transmission line that would connect the site to the nearest access point on the ERCOT grid or by upgrading the existing lines. There may be important differences between the sites regarding the additional amount of capacity that can reasonably be added and the cost of doing so. There may also be important differences in the impact on the overall project schedule: upgrades can be done relatively quickly; new lines in the existing right of ways may need only a limited amount of additional environmental studies; and expansion of the right of way corridor may take very long indeed since it likely involves a full blown permitting effort. A typical transmission line is shown in Figure 2.5.

Figure 2.5. Typical Electric Transmission Line.

2.6.7.2. Background

Before discussing the pros and cons of the different sites, let us review some necessary background.

- **ERCOT and Congestion Management**

  ERCOT is an open access grid, a map of which is provided in Appendix 2H (ERCOT Control Area.) This means a generator can connect to the grid at any point and ship the power to any other location.[21] There is, of course, a transmission fee paid for by the customer. This fee is based upon the amount of electricity in kWh that is transferred from the plant to the customer's load.

  In addition to the normal transmission tariff, customers may be subject to a Congestion Management fee.[22] ERCOT is divided into five Zones for purposes of managing congestion on the grid. If electricity is transferred from one zone to another there may be a congestion management fee, the amount of which will depend upon the imbalances between the loads and the sources of generation in effect at the time of the transfer.

  ERCOT information indicates that the Houston and North (includes Dallas-Fort Worth) Zones have no reserves during the summer months and must import electricity from other regions that have excess capacity. This situation is particularly acute for the Dallas area where imports already top 6000 MWs, a level that will persist for several years. Because of this need to import, these two zones account for over 80% of the congestion management fees incurred within ERCOT as whole. In particular, the STP to DOW (in south Houston) connection has been identified as a Commercially Significant Constraint at certain times.

- **Increasing Transmission Capacity**

  According to ERCOT[23], there is little unused transmission capacity in the ERCOT control area, including at the STP and Comanche Peak nuclear power stations. The construction of a new nuclear plant, therefore, must be accompanied by an increase in transmission capacity either by the construction of a high voltage transmission line that would connect the site to the nearest access point on the ERCOT grid or by upgrading the existing lines. Other improvements and modifications to the grid will also be necessary to account for the presence of a 1400 MW generator.

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21 This will be necessary for a new nuclear plant that has bi-lateral contracts for delivery to end-users at specific locations–as opposed to selling electricity into a pool.

22 "Congestion is a situation that exists when requests for power transfers across a Transmission Facility element or set of elements, when netted, exceed the transfer capability of such elements." –ERCOT definition.

23 Conversation with the Director of Transmission Services and the Manager, Transmission Planning, August 2004.

- **Constructing New Transmission Lines**

  A single circuit, 345-kv transmission line (on one pole) can carry between 500 and 700 MWs of electricity. A double circuit, 345-kv transmission line (also on one pole) can therefore carry between 1000 and 1400 MWs. Roughly, then, in order to transfer the output of the available nuclear plants to the grid would require several lines, as follows

Table 2.7. Number of Electrical Lines and Arrangements for Different Reactor Outputs.

Plant	Net Output	Number of Lines	Alternative Arrangement
AP1000	App. 1150 MW	2 - single circuit lines	1 - double circuit line
ABWR, ACR700	App. 1400 MW	2 or 3 - single circuit lines	1 - double circuit line 1 - single circuit line
ESBWR, EPR	App.1500 MW	3 - single circuit lines	1 - double circuit line 1 - single circuit line

There are obvious cost advantages to the double circuit line, especially if the existing right of way (ROW) corridor has physical limitations that would require buying or leasing land in order to expand the corridor.

The disadvantage of the double circuit line is that by itself it does not meet the NRC's requirement for redundancy in the supply of offsite power to the plant. This may not be an issue with existing sites that has several lines connecting the plant to the grid. Presumably the plant distribution system could be configured to provide power to the new unit in addition to the existing ones.

The approximate cost of a 345-kv line is $1.5 M per mile or $4-5M per mile if the line is put underground. The time needed to permit, construct, and energize the transmission line is between three and eight years, a wide range that is indicative of both the uncertainty involved in the permitting process (almost always a contentious undertaking) and the importance of having an existing right of way. If there is an existing right of way with enough physical space to accommodate another line, ERCOT believes the time needed will be closer to three years. Having a right of way is obviously a critical consideration.

- **Upgrading the Existing Capacity**

Another way to increase the transfer capability is to reconductor the existing transmission lines. This is a proven way to increase the capacity of existing lines but has provided only limited relief. However, there is a new conductor made by 3M that is just now entering commercial application.[24] This conductor, known as Aluminum Composite Conductor Reinforced (ACCR), is an overhead power conductor that doubles the electrical transmission capacity of conventional conductors of the

[24] "Xcel Energy to Install 3M's ACCR Breakthrough Bottleneck Solution", http//tdworld.com/mag/power_xcel_energy_install/ .

same diameter. As 3M's product brochure indicates:

> "The new technology could offer many benefits for utilities. Perhaps most significantly, installation of the smaller 3M ACCR could help relieve transmission bottlenecks that prevent lower-cost energy from being dispatched to where it is needed. This conductor could also be installed in locations where utilities could uprate lines without increasing the width of existing rights-of-way. The conductor's high strength-to-weight ratio also could offer a solution for long-span applications."[25]

More information on this new conductor is found in Appendix 2H.

After the connection point, the existing transmission grid may need to be upgraded to handle the new power flows. Detailed interconnection and load flow studies are performed by the Transmission Service Provider to determine the nature and extent of these upgrades.

2.6.7.3. What the Data Says

From our many conversations on the topic of transmissions with ERCOT, the utilities, and the Transmission Service Providers, we have concluded that <u>it is premature to form any conclusions at all on transmission issues until the detailed interconnection and load flow studies are done.</u> These studies determine such basic issues as the use of existing lines, the number and size of new lines, and the need for additional right of way, and so on.

It is also important to note that ERCOT is currently in the midst of significantly upgrading the grid, specifically to relieve the current congestion (which has a cost of $300M per year in fees and Reliability Must Run (RMR) contract payments.) By the time the proposed nuclear plant enters the development phase and certainly by the time it is operational, the physical and operational characteristics of the ERCOT grid will have changed substantially.

We can, however, make note of some key facts that may influence the outcome of those studies.

Comanche Peak

This is a compact site with, it appears, space for one additional unit. This compactness also puts a premium on space for an expansion of the switchyard. Finally, the existing transmission lines and therefore the right of way corridor were sized for two units. Access to sufficient transmission capacity is, therefore, likely to involve some challenges.

South Texas Project

There are four owners of STP. To accommodate the needs of each owner, the right of way corridor was sized for multiple lines. There are currently five 345-kv lines in this jointly owned corridor and one line with a smaller voltage rating. There is additional space within this corridor. Moreover, the

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[25] http//www.3m.com/market/industrial/mmc/accr/index.jhtml .

site itself was designed for additional nuclear units and there appears to be adequate room for the additional substations needed.

2.6.7.4. Evaluation

Although a comparison of the two sites based upon the facts cited above might lead one to conclude that STP is the better site in terms of transmission, it is important to keep in mind that such a conclusion is premature and could change significantly once the detailed studies are performed. Based upon the advice of the experts, we believe it prudent to withhold an evaluation at this time, especially since the transmission criteria has the highest weight factor of the ten evaluation criteria.

2.6.7.5. Next Steps

We highly recommend that in the next phase of this study, money be budgeted to perform both the ERCOT screening study and the more detailed load flow analyses. The ERCOT study will cost $5,000 per site and will be done on a confidential basis (for competitive reasons.) This analysis takes 90 days to complete. The detailed study, which will be done by a TSP such as Reliant or TXU costs about $100,000 per site and 3 months to complete.

2.6.8. Power Pricing

2.6.8.1. Why is This Important?

The cost of electricity includes both energy (or generation) and delivery costs. While the energy cost is independent of location, the delivery cost is not. If there are bottlenecks on the grid, the plant owner may incur congestion management fees[26] or pay to acquire firm transmission rights in order to transport the electricity from the plant to the customer's site. In a market characterized by competition, the plant owner may not be able to pass along all of these costs to customers.
These bottlenecks and congestion can become so severe that electricity can neither be imported nor exported and a "local reliability pocket" develops. If within this pocket there is more demand than there supply, a reliability problem develops which the grid operator attempts to solve by entering into costly Reliability Must Run (RMR) contracts in the short term and relieving the constraints with transmission reinforcement projects in the long run.

When the opposite occurs--the supply of electricity within the local pocket exceeds the demand–the grid operator will seek to export it to other regions. Often times, the surplus power to be exported exceeds the transfer capacity in which case some of the plants are ordered by the grid operator to ramp down, a practice known as "regulation down." If this occurs on a persistent basis, there will be downward pressure on electricity prices as generators compete to stay online.

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[26] ERCOT does have such bottlenecks and is divided into five zones for purposes of managing congestion on the grid. Inter zonal fees reflect the fact that there is limited capacity to transmit electricity from one zone to another.

2.6.8.2. What the Data Says

One must rely upon projections of electricity prices for ERCOT as a whole and then for the specific zone in which the plant might be located. (STP is located in the South Zone and Comanche Peak within the North Zone.) Naturally, such projections are difficult due to many factors that can't be known with any certainty. For example, how many power plants will be built and where? Where and when will the grid be upgraded?

As discussed above, we do know that there is significant congestion between the South and Houston Zones and between the North and Houston Zones. If this congestion persists, then no matter which site is chosen there would be significant Congestion Management Fees incurred in transferring generation to loads to the chemical end users located in the Houston ship channel. Transmission losses would also be about the same for either site.

2.6.8.3. Evaluation

It is difficult to make an evaluation based upon the information currently available. More information would be available in the future as ERCOT's plans to increase the capacity of the grid. Indeed a significant number of projects are either approved or are in the process of being approved. Also, there is a proposal to shift to nodal pricing which would have a significant impact on Congestion Management.

2.6.9. Plans for Existing Units

2.6.9.1. Why is This Important?

If a new plant is to be located at the site of operating units, the associated licensing and construction activities have the potential to interfere, in terms of engineering logistics and regulatory interactions, with any plans for license extension or major maintenance (e.g., steam generator replacement). Such plans might therefore affect the timing of the plant construction.

2.6.9.2. What the Data Says

Comanche Peak

The operating license for unit 1 expires in 2030 and that for unit 2 in 2033. Comanche Peak is currently in the 15th year of a 40 year license. NRC regulations do not allow renewal licenses to be filed until the unit has been in service 20 years. There is no reason to believe TXU Power will not extend the license for Comanche Peak at the appropriate time. The Unit 1 steam generators will be replaced in the refueling outage that is scheduled for the Spring, 2007. There are currently no plans to replace the steam generators in Unit 2.

South Texas Project

The operating licenses for Units 1 and 2 expire in August 2027 and December 2028, respectively. STP management advised us that there are no plans currently to extend these licenses. The steam generators for both units have been replaced and no major construction or plant modification activities are planned.[27]

2.6.9.3. Evaluation

Neither site is reasonably expected to have construction or major modifications that might interfere with the construction of new units. Both score high in this regard (5, the highest.)

2.6.10. Spent Fuel Storage

2.6.10.1. Why is This Important?

Although the President and the Congress have approved Yucca Mountain to be the site of the nation's spent fuel repository, it is still subject to NRC licensing. Because this is proving to be a contentious process and there are several open technical issues in need of resolution, it is difficult to predict when the repository will begin accepting the spent fuel currently stored at the 72 plant sites around the country (although officially the date is 2010.)

In the interim, many plant owners will need to build additional "on-site" spent fuel storage facilities, if they haven't done so already. The space required for this storage facility must be taken into account (and given priority) when considering the location and layout of the new plant and certainly later when the COL is prepared.

2.6.10.2. What the Data Says

Comanche Peak

Comanche Peak does not currently have any storage pads or bunkers and presently has no plans to construct any such storage facility. Comanche Peak's spent fuel is presently being stored in its storage pools located in the Fuel Building.

South Texas Project

Each STP unit has a 29' by 52' spent fuel pool (located within each unit's fuel handling building) that has sufficient storage for the life of the plant. There are currently no plans to construct additional on-site storage for spent fuel.[28]

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[27] Letter dated October 4, 2004 from Mr. Ed Halpin, Vice President and assistant to the President & CEO, STP to Dr. Charles Holland, President, Texas Institute for the Advancement of Chemical Technology.

[28] Ibid.

2.6.10.3. Evaluation

There are two considerations here. The first is that the layout and construction of one or two additional units on either site will not be made difficult by the presence of an on-site spent fuel storage facility. Also, the nuclear plants being offered today are designed to store 10 years worth of spent fuel in the storage pools located in the reactor building. This means that it will be about 25 years, measuring from today, before this capacity has been used. If and when additional spent fuel storage space is needed, it is available.

Neither site needs additional spent fuel storage capacity for its operating units. This means that room does not need to be reserved for future on on-site storage. Since the new units won't need additional storage capacity either, the placement and layout of the new unit or units is made simpler. Both sites receive high marks (5, the highest.)

2.7. EVALUATING THE CANDIDATE SITES FOR ENVIRONMENTAL SUITABILITY

Now that the 10 criteria evaluation for addressing if any fatal flaws exist in the technical elements or in the business case of locating a new plant at these two sites, the next step is to review each against the criteria found in Sections 3.1.2, 3.1.3, and 3.2 of the Siting Guide. These criteria provide an objective framework for evaluating and ranking the environmental suitability of existing Comanche Peak and STP sites.

If one or both of the two proposed sites can be shown to be highly suitable for all of the environmental criteria, or conversely if there is no criterion for which the sites are deemed highly unsuitable, it can be argued that no environmentally preferable site exists. If the analysis shows that the proposed sites rank low in suitability for one or more environmental criteria, then alternative sites would be evaluated in future work.

Appendix 2C lists the criteria from the Siting Guide to determine the environmental suitability of sites with existing nuclear power plants. The criteria described in Sections 3.1.2, 3.1.3, and 3.2 of the Site Guide are given in Appendix 2C provide the basis for evaluating and ranking the sites' environmental suitability for adding a new plant. Not all of the environmental criteria from Sections 3.1.2, 3.1.3, or 3.2 of the Siting Guide were evaluated for this study. Eleven criteria were picked as being "more important" or representative and it is believed will provide a good basis for the environmental acceptability of the sites for an additional new unit(s). Obviously, all the criteria will need to be addressed in the future as part of the ESP or COL application. The eleven criteria are given in Table 2.8.

Table 2.8. Selected Environmental Criteria

Siting Guide Section*	Topic
3.1.2.1	Population
3.1.2.2	Emergency Planning
3.1.2.3	Atmospheric Dispersion - Accident Effects
3.1.3.1.3	Proximity to Consumptive Users
3.1.3.2	Groundwater Radionuclide Pathway (Steps 1&2)
3.1.3.3.2	Atmospheric Dispersion - Operational Effects
3.1.3.5	Surface Water - Food Radionuclide Pathway
3.2.2.1	Disruption of Important Species/Habitats and Wetlands
3.2.2.1.3	Wetlands
3.2.3.1.1	Migratory Species Effects
3.2.3.1.2	Disruption of Important Species/Habitats

* Siting Guide: EPRI Technical Report 1006878, March 2002; used here by permission of the Electric Power Institute (EPRI).

2.7.1. Criterion 3.1.2.1 (Population)

The population distribution surrounding a site must meet conditions of 10 CFR 100.21 for exclusion area, LPZ, and population-center distance and Regulatory Guide 4.7 for population density. This evaluation was performed in Section 2.5.4, “Demographic Changes”, and 2.5.5, “Exclusion Area”. Both sites were found to score high (5 out of 5) and to be environmentally suitable in terms of this criterion.

2.7.2. Criterion 3.1.2.2 (Emergency Planning)

Emergency planning must meet 10 CFR 50, 52, and 100 requirements in that nuclear power facilities must have adequate plans to protect members of the public in emergencies. Additional guidance for emergency planning is provided in NRC Regulatory Guide 4.7.

The emergency planning evaluation is provided in Section 2.5.6, “Emergency Planning”of the Siting Guide. Both sites have existing Emergency Plans. Taking into account the safety features of the new designs and the low population density of the surrounding communities, the potential for offsite radiation exposure to the public would not increase should new units be added at either site. It is not anticipated that changes should occur to the existing Emergency Plans. Both sites were found to score high (5 out of 5) and be environmentally suitable in terms of this criterion..

2.7.3. Criterion 3.1.2.3 (Atmospheric Dispersion - Accident Effects Related)

2.7.3.1. Why is This Important?

Atmospheric dispersion at the candidate sites need to provide sufficient dispersion of radioactive materials released during a postulated accident to reduce the radiation exposures for individuals at the exclusion area boundary (EAB) and low population zone boundary (LPZ) to the values in 10 CFR 50.34 and 10 CFR 100.11.

2.7.3.2. What is the nature of This Criterion?

The parameter used to evaluate atmospheric dispersion is an estimated ambient concentration normalized by the emission rate (X/Q in units of sec/m^3). The X/Q values are independent of emission rate and represent a measure of the atmospheric dispersion at a representative location. Short-term X/Q meteorological estimates (5 or 10 percentile) are used to evaluate accident condition radiation exposures.

Plant Parameter Envelope(PPE) values for X/Qs have been developed for AP1000 passive design and the advanced design ABWR. Site X/Qs that compare favorably with the PPE X/Qs demonstrate sufficient atmospheric dispersion to meet the EAB and LPZ radiation exposure 10 CFR 100.11 requirements.

Engineered safety features that reduce the plant radiation emission rate can also compensate for unfavorable atmospheric characteristics.

2.7.3.3. What the Data Says

Table 2.9 shows a comparison of X/Qs for South Texas and Comanche Peak sites with Plant Parameter Envelope Values (PPEs) for the passive design AP1000 and advanced design ABWR. X/Q values for 0-2 hrs are representative for an exclusion area boundary (EAB) radiation exposure while the X/Q values for 0-8 hrs, 8-24 hrs, 24-96 hrs, and 96-720 hrs are representative for a low population zone (LPZ) radiation exposure.

2.7.3.4. Evaluation

South Texas and Comanche Peak have X/Q values less than the AP1000 and ABWR PPE values at their EAB and LPZ boundaries and therefore demonstrate favorable atmospheric dispersion that should not preclude either site from being acceptable for meeting 10 CFR 50.34 and 10 CFR 100.11 radiation exposure requirements. Both sites score high (5 out of 5) and are environmentally suitable in terms of this criterion.

Table 2.9. Comparison of Accident X/Qs (sec/m^3)

Accident Period	AP-1000[a]	ABWR[a]	South Texas Project[b]	Comanche Peak[c]
0-2 hrs	6.1E-04	1.4E-03	1.3E-04	1.3E-04
0-8 hrs	1.4E-04	1.6E-04	1.6E-05	2.4E-05
8-24 hrs	1.0E-04	1.2E-04	8.0E-06	1.6E-05
24-96 hrs	5.4E-05	4.2E-05	3.6E-06	6.2E-06
96-720 hrs	2.2E-05	9.2E-06	1.1E-06	1.7E-06

a. EAB - 800 m, LPZ - 3.2 km, Reference 1
b. EAB - 1430 m, LPZ - 4.8 km, Reference 2
c. EAB - 2106 m, LPZ - 6.4 km, Reference 3

2.7.4. Criterion 3.1.3.1.3 (Proximity to Consumptive Users)

2.7.4.1. Why is This Important?

This is one of three of the Guide’s considerations for the Operational Effects-Related criterion or the Surface Water –Radionuclide Pathway. In addition to proximity to downstream water users, this criterion considers the dilution capacity of the surface water discharge receiving stream(s) and current baseline loadings on the receiving stream(s). This consideration seeks to identify, for each candidate site, the locations of downstream public water supply withdrawals and recreational contact users. Those sites with fewer nearby downstream public water supply withdrawals and downstream recreational users are favored over those sites with greater downstream users.

2.7.4.2. What the Data Says

Comanche Peak

Operational surface water discharges from the candidate site at the Comanche Peak Plant would be to either the Squaw Creek Reservoir, Squaw Creek (below the reservoir dam) or to the Brazos River. All of these discharges would ultimately become part of the Brazos River mainstem flow downstream of the Squaw Creek-Paluxy River confluence with the Brazos River near Rainbow, Texas. Surface water uses for Texas are designated in 30 Texas Administrative Code § 307.10(1) Appendix A. The main stem of the Brazos River downstream of the Comanche Peak Plant is designated for secondary contact recreation uses (e.g., boating, wading, fishing but not swimming), but it is not designated for public water supply uses.

Whitney Lake is located on the main stem of the Brazos River approximately 30 miles downstream of the Comanche Peak Plant site. Whitney Lake is designated for public water supply uses. There are no public water supply intakes on Whitney Lake at the present time.[29] The principal condition limiting usefulness of Lake Whitney water as a public water supply is salinity. Because of the salinity conditions, public surface water supplies in this portion of the Brazos River basin are located on tributary streams (e.g., Aquilla Lake and Waco Lake) and thus would not be affected by surface water discharges from the candidate site at the Comanche Peak Plant.

South Texas Plant

Operational surface water discharges from the candidate site at the STP would be to either the MCR, downstream of the MCR dam or the Colorado River. All of these discharges would ultimately become part of the main stem of the Colorado River flow below the MCR discharge confluence with the Colorado River. The Colorado River mainstem downstream of the STP is designated for secondary contact recreation uses (e.g. boating, wading, fishing but not swimming) but it is not designated for public water supply uses. As noted in Section 3.5.3.3 (Water Availability) of the Siting Guide, this portion of the Colorado River is within the zone of tidal influence from the Gulf of Mexico. There are no public water supply intakes on this portion of the Colorado River.

2.7.4.3. Evaluation

The absence of downstream public water supply intakes for both sites ranks them near the top for this consideration. There are potential downstream secondary contact recreational uses for both sites and this negates a perfect score. In the absence of definitive information on the actual nature of the downstream recreational uses, both sites are rated at 4.5 out of 5 for this criterion.

2.7.5. Criterion 3.1.3.2 (Groundwater Radionuclide Pathway (Hydo & Rad))

2.7.5.1. Why is This Important?

Accidental releases of radiologically contaminated liquids to aquifers that are or may be used by large populations for domestic, municipal, industrial, or irrigation water supplies, will provide potential pathways for the transport of radioactive material to humans in the event of an accident. The characteristic of any aquifer within EPA defined two-mile radius of the plant must be evaluated to assess site suitability.

2.7.5.2. What the Data Says

Comanche Peak Site

An analysis of the site is documented in Section 2.4.13 of the CPSES FSAR that concludes that there is no hazard to the general public due to groundwater radionuclide pathways. The proposed unit addition would be built on the developed land at the existing site. The groundwater geology of the site has not changed since the time of the existing analysis.

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[29] Information on Whitney Lake and public water supplies from phone interview with Ronnie Bruggman, U.S. Army Corps of Engineers, Whitney Lake.

In 1984 the EPA issued Guidance for Groundwater Classification. There are no Class I (special groundwater) aquifers in the vicinity of the site.

South Texas Project Site

An analysis of the site is documented in Section 2.4.13 of the STP FSAR that concludes that there is no hazard to the general public due to groundwater radionuclide pathways. The proposed unit addition would be built on the developed land at the existing site. The groundwater geology of the site has not changed since the time of the existing analysis.

In 1984 the EPA issued Guidance for Groundwater Classification. There are no Class I (special groundwater) aquifers in the vicinity of the site.

2.7.5.3. Evaluation

Candidate site “A” rests above the Twin Mountains formation, which underlies the relatively impermeable Glen Rose formation. The Glen Rose formation supplies very limited amounts of groundwater through wells for livestock and rural domestic use (less than 100 acre-ft per year). The Twin Mountains formation is the primary source of groundwater in the region, although this use is not extensive (projected to increase to less than 200 acre-ft per year by 2020). Therefore this site is rated a 4 in this category.

The proximity to the Gulf of Mexico of Candidate Site "B" assures that all aquifer pathways run towards the Lower Colorado River or the Gulf. Few domestic, municipal, industrial, or irrigation water supplies are located between the plant and the Gulf. Therefore the Candidate Site "B" is rated a 5 in this category.

2.7.6. Criterion 3.1.3.2 (Atmospheric Dispersion - Operational Effects – Related)

2.7.6.1. Why is This Important?

Atmospheric dispersion at candidate sites should provide sufficient dispersion of radioactive materials released on an annual average basis from plant operation that radiation exposures for individuals at the site boundary not exceed 10 CFR 50 Appendix I requirements.

2.7.6.2. What is the Nature of This Criterion?

Annual average X/Qs are independent of emission rate and represent a measure of the atmospheric dispersion at the site boundary. PPE values for annual average X/Qs have been developed for the passive design AP1000 and the advanced design ABWR. Site X/Qs that compare favorably with PPEs X/Qs demonstrate sufficient atmospheric dispersion to meet 10 CFR 50 Appendix I requirements.

2.7.6.3. What the Data Says

Table 2.10 shows a comparison of annual average X/Q values for South Texas and Comanche Peak with the annual average PPE X/Q values for the passive design AP1000 and the annual average PPE X/Q value from the ABWR.

South Texas and Comanche Peak have X/Q values less than the AP1000 PPE X/Q value and should not preclude either site as being acceptable for meeting 10 CFR Appendix I radiation exposure limits.

Comparison of the South Texas annual average X/Q with the ABWR X/Q value shows acceptable atmospheric dispersion. Comparison of the Comanche Peak annual average X/Q with the ABWR X/Q value also shows acceptable atmospheric dispersion if one considers resultant airborne dose impacts. Airborne dose impacts were significantly below 10 CFR 50 Appendix I requirements for the ABWR SSAR analysis (Reference 4 below) and application of Comanche Peak X/Qs to the ABWR SSAR radiological release source terms would show dose impacts below 10 CFR 50 Appendix I requirements. A list of references used in the above analyses are listed below.

2.7.6.4. Evaluation

South Texas Project scores a 5 and Comanche Peak a 4.5, both quite high. Both sites are environmentally suitable in terms of this criterion..

References

1. “Plant Parameters Envelope (PPE) Worksheet”, Nuclear Energy Institute (NEI), Revision 0, February 2003.
2. “South Texas Project Updated Final Safety Analysis Report”, STP Nuclear Operating Company.
3. “Comanche Peak Updated Final Safety Analysis Report”, Comanche Peak Steam Electric Station, TXU, Electric.
4. “ABWR Standard Safety Analysis Report,” GE Nuclear Energy, June 1994.

Table 2.10. Annual Average X/Qs (s/m^3)

Location	X/Q (s/m^3)
AP1000[a]	2.0E-05
ABWR[a]	1.2E-06
South Texas Project[b]	1.1E-06
Comanche Peak[c]	3.3E-06

a. EAB - 800m, Reference1.
b. Site boundary - 1.5 km, Reference 2.
c. Site boundary - 1.3 km, Reference 3.

2.7.7. Criterion 3.1.3.5 (Surface Water-Food Radionuclide Pathway (Hydro, Rad & LU))

2.7.7.1. Why is This Important?

In addition to groundwater pathways identified in Section 2.7.5, irrigation water in downstream areas is another potential pathway for radionuclides. Potential sites need to be evaluated to assess site suitability.

2.7.7.2. What the Data Says

Comanche Peak Site

An analysis of the site is documented in Section 2.4.12 of the CPSES FSAR that concludes that there is no hazard to the general public due to surface water-food radionuclide pathways. The proposed unit addition would be built on the developed land at the existing site. The topography of the developed site will not change significantly with the new unit addition. The design of advanced light water reactors provides additional protection against operational and accidental release of radioactivity.

The existing analysis concluded that the environment could accept normal, inadvertent, or accidental releases of radioactive liquid effluents without undue risk to the general public based on dilution by the waters of Squaw Creek Reservoir.

South Texas Project Site

An analysis of the site is documented in Section 2.4.12 of the STP FSAR that concludes that there is no hazard to the general public due to surface water-food radionuclide pathways. The proposed unit addition would be built on the developed land at the existing site. The topography of the developed site will not change significantly with the new unit addition. The design of advanced light water reactors provides additional protection against operational and accidental release of radioactivity.

The existing analysis concluded that the environment could accept normal, inadvertent, or accidental releases of radioactive liquid effluents without undue risk to the general public. The Colorado River opposite the site was determined to be unsuitable as a potable water source and only suitable for irrigation during higher river flows. The Lower Colorado Regional Water Planning Group estimates usage for water in the overall region to decrease for irrigation uses and remain steady for livestock usage for the next 50 years.

2.7.7.3. Evaluation

Candidate site “A” is located on the Squaw Creek Reservoir. This reservoir has been used in the past for recreational fishing and is used as a source for irrigation of areas downstream. The reservoir waters provide a significant volume of water for dilution of any surface water releases. This site is rated a 3.5 in this category.

Candidate site "B" is located upstream of intermittent irrigation and livestock water usage as well as the Gulf of Mexico. Based on this and the above information this site is rated a 4 in this category.

2.7.8. Criterion 3.2.2.1 (Construction Related Disruption of Important Species/Habitats and Wetlands)

2.7.8.1. Why is This Important?

Candidate sites that have the potential for the presence of threatened, endangered or otherwise important species should be avoided. The Texas Parks and Wildlife Department currently counts 191 species as federal and state listed threatened or endangered in Texas. These include 33 mammals, 31 fishes, 25 reptiles, 12 amphibians, 39 birds, 22 invertebrates and 29 plants.

2.7.8.2. What the Data Says

Comanche Peak

The Comanche Peak Plant is located in the Western Cross Timbers subregion of the Oak Woods and Prairies ecoregion of Texas.[30] The information reviewed for this assessment indicates that Comanche Peak Plant site is not included in designated critical habitat for any of the Texas listed threatened or endangered species.[31] Certain wide ranging endangered species, such as Large Fruited Sand Verbena (Abrania macrocarpa) have some potential to occur in the area but are not specifically known to be present at the site.

South Texas Project

The STP site is located in the Uplands Prairies and Woods subregion of the Gulf Coastal Prairies and Marshes ecoregion of Texas.[32] The information reviewed for this assessment indicates that the STP site is not included in designated critical habitat for any of the Texas listed threatened or endangered species.[33] Certain wide-ranging endangered species, such as South Texas Ambrosia (Ambrosia cheiranthifolia) have some potential to occur in the area but are not specifically known to be present at the site.

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[30] Natural Subregions of Texas, compiled by Texas Parks and Wildlife Department, GIS Lab, 1995. http//www.tpwd.state.tx.us/gis/downloads/pdf/natsub24.pdf .

[31] Formal consultations with the US Fish and Wildlife Service and the Texas Parks and Wildlife Department concerning important species would be necessary to confirm this finding.

[32] Natural Subregions of Texas, compiled by Texas Parks and Wildlife Department, GIS Lab, 1995. http//www.tpwd.state.tx.us/gis/downloads/pdf/natsub24.pdf .

[33] Formal consultations with the US Fish and Wildlife Service and the Texas Parks and Wildlife Department concerning important species would be necessary to confirm this finding.

2.7.8.3. Evaluation

The Guide indicates a score of 4 for each site because they are in the known range of important species but no suitable habitat exists due to past land disturbance.

2.7.9. Criterion 3.2.2.1.3 (Wetlands)

2.7.9.1. Why is This Important?

Federal guidance and regulations require that the destruction or modification of wetlands be avoided unless there are no practical alternatives.

2.7.9.2. What the Data Says

Comanche Peak

National Wetland Inventory Maps are not available for the candidate site at the Comanche Peak Plant. The Hill City, Texas 7.5-minute USGS Topographic Quadrangle Sheet does not indicate the presence of extensive wetlands at the candidate site.

South Texas Project

The National Wetland Inventory Map covering the STP plant site and surrounding areas indicates that significant wetlands are present in the surrounding area but no significant wetlands are indicated at the candidate site.

2.7.9.3. Evaluation

The Guide indicates that both candidate sites should receive a score of 5 because no significant wetlands are present.

2.7.10. Criterion 3.2.3.1.1 Operational Related (Thermal Discharge) Migratory Species Effects

2.7.10.1. Why is This Important?

Candidate sites must be evaluated for their potential impacts on migratory birds, including gold and bald eagles.

2.7.10.2. What the Data Says

Thermal discharge to aquatic ecology will be limited to cooling tower blowdown because this assessment assumes that the Proposed TIACT plant will use closed cycle cooling rather than once through cooling. Discharge of cooling tower blowdown must be permitted through the TDEQ and will have no adverse effects on migratory birds.

2.7.10.3. Evaluation

Both candidate sites score 5 because of minimal thermal discharges to aquatic environments.

2.7.11. Criterion 3.2.3.1.2 (Operational Related (Thermal Discharge) Disruption of Important Species/Habitats)

2.7.11.1. Why is This Important?

Candidate sites should be screened to ensure that thermal discharges would not disrupt important aquatic species or their habitats.

2.7.11.2. What the Data Says

As noted in Section 2.7.8.2 above, neither of the candidate sites is located within designated critical habitat for Texas or federally listed threatened or endangered species. Furthermore, as noted in Section 2.7.10.2 above, this assessment assumes that the Texas Gulf Coast Nuclear plant will use closed cycle cooling rather than once-through cooling. Therefore, the potential for thermal effects on important species or their habitats is minimal.

2.7.11.3. Evaluation

Both candidate sites score 5 because of the minimal potential for thermal effects on important species or their habitats.

2.8. SUMMARY AND CONCLUSIONS

The sites of the two existing nuclear plants in Texas, Comanche Peak and South Texas Project would be make good hosts for additional nuclear units. This conclusion is based upon a high level screening analysis that used 10 evaluation criteria. This evaluation did not uncover any issues that would disqualify either site from further consideration. Indeed, the characteristics of each site were found to be highly favorable or favorable in all respects.

The numerical results of this evaluation are given in Table 2.11 below. Although the numbers indicate a slightly higher score for South Texas Project, this should not be taken as definitive or that a preference exists. Indeed, we believe that other considerations, such as the interest of the site owner for participation in a new plant project, will dictate which of these sites or yet another greenfield site will be selected. That selection process lies in the future.

Table 2.11. Summary of Evaluations of the Comanche Peak and South Texas Project Sites

Site Evaluation Criteria	Weight Factor	Comanche Peak	South Texas Project
Seismic Evaluation	0.70	5	5
Permitting/Licensing Status	0.72	5	5
Water Availability	0.35	5	5
Demographic Changes	0.61	5	5
Exclusion Area	0.65	5	5
Emergency Planning	0.75	3	5
Transmission Access	0.74	Not scored	Not scored
Power pricing	0.93	1	2
Plans for Existing Units	0.40	5	5
Spent Fuel Storage	0.76	5	5
TOTAL (29.35 possible)		24.33	26.56

In addition, these sites were found to be superior sites in terms of environmental suitability. This determination was reached by assessing the sites against a set of environmental criteria from the EPRI guide that were deemed to be the most significant. These criteria fairly depict (in more detail than the previous set of criteria) the environmentally suitability of each site. The results are given in Table 2.12.

Table 2.12. Selected Environmental Criteria

Environmental Suitability Criteria	Comanche Peak	South Texas Project
Population	5.0	5.0
Emergency Planning	5.0	5.0
Atmospheric Dispersion	5.0	5.0
Proximity to Consumptive Users	4.5	4.5
Groundwater Radionuclide Pathway	4.0	5.0
Atmospheric Dispersion - Operational Effects	4.5	5.0
Surface Water - Food Radionuclide Pathway	3.5	4.0
Disruption of Important Species/Habitats and Wetlands-Construction Related	4.0	4.0
Wetlands	5.0	5.0
Migratory Species Effects	5.0	5.0
Disruption of Important Species/Habitats--Operational	5.0	5.0
Total (55 possible)	50.5	52.5

TASK 3

ASSESS AVAILABLE TECHNOLOGIES

TASK 3. ASSESS AVAILABLE TECHNOLOGIES

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TASK 3. ASSESS AVAILABLE TECHNOLOGIES

3.1. INTRODUCTION

This task evaluates the nuclear, desalination, and hydrogen producing technologies that are currently available or reasonably expected to be available in time to support the ultimate objectives of this study: (1) to ascertain the feasibility of building a nuclear plant on the Texas Gulf Coast in support of TIACT's business objectives, and (2) if feasible, to have a nuclear plant in commercial operation within the guidelines envisioned by DOE Vision 2010.

Task 3 includes a survey of nuclear plant suppliers conducted to obtain the following information:

- U.S. licensing status, including the expected date of design certification or the readiness of the design to be part of a Construction and Operating License (COL) submittal;
- Operational experience, if any;
- Technical information that characterizes the key design features;
- Engineering, procurement, and construction (EPC) cost information for a single, stand-alone unit to be built in Texas;
- Construction and overall project schedule as measured from the execution of a contract;
- Design information for use in evaluating the applicability of the plant to the potential sites;
- Project management and contracting arrangements, and partners;
- Willingness to offer scope on a fixed price basis and to offer liquidated damages for schedule delays;
- Willingness to make an equity investment in the project.

Also included is the development of a set of criteria for ranking each plant design relative to its ability to meet the CTQs ("Critical to Quality") requirements of end users[1].

On the basis of these criteria a recommendation is made about which supplier designs should be included in the future plans for the procurement of generating capacity. This report also provides the end users and potential plant owners with selection criteria.

1 CTQs represent requirements which must be met to satisfy the needs of end-users or other stakeholders (i.e., investors).

3.2. PRINCIPAL FINDINGS

3.2.1. Nuclear Technology Summary

The global commercial nuclear industry offers multiple technology options for medium to large generation capacity additions. A summary including key features and status of the nine technologies evaluated during this study is provided in Table 3.1. This list includes designs representing four broadly defined reactor types:

1) Boiling Water Reactors or BWR,
2) Pressurized Water Reactors or PWR,
3) Pressurized Heavy Water Reactors or PHWR and
4) Gas Cooled Reactors or GCR.

A more detailed discussion of these designs follows in section 3.4 'Task Results' below.

Table 3.1. Summary of Evaluated Nuclear Generation Technologies

Design	Capacity (MWe net)	Supplier	Technology	Key Features & Status
ABWR	1320 to 1400	GE	BWR	• Evolutionary design • Design certified at 1320 MWe in 1997 • Plans to uprate to ~ 1400 MWe • $4M detailed study led by TVA for 2 units at Bellefonte site to be completed by early 2005 • 3 units operating in Japan and 3 more under construction (2 in Taiwan and 1 in Japan)
ACR-700	703	AECL	PHWR	• Reoptimized fuel and moderator for better overall economics • Heavy water (D_2O) moderation • Added enriched fuel and light (H_2O) cooling • On line refueling • Design certification underway
AP1000	1177	Westinghouse (BNFL)	PWR	• Scale up from AP600 design which was design certified by the U.S. NRC in 1999 • Design certification expected in 2005 • One of two technologies being considered by the NUSTART consortium
EPR	1600	Framatome ANP (Areva)	PWR	• 1st unit ordered in Finland for 2009 startup • Evolutionary design • U.S. design certification plan not formalized

Table 3.1. Summary of Evaluated Nuclear Generation Technologies

Design	Capacity (MWe net)	Supplier	Technology	Key Features & Status
ESBWR	1400	GE	BWR	• Passive safety design basis • Scale up of 600 MWe SBWR design • Pre-certification review pending • One of two technologies being considered by the NUSTART consortium • Selected by Dominion for COL project
GT-MHR	288	General Atomics	GCR	• Helium cooled direct cycle modular design • Coated particle fuel in prismatic core • Potential Generation IV demonstration plant at the Idaho National Lab (INEEL)
IRIS	335	Westinghouse (BNFL)	PWR	• Integrated Primary System • Potential for improved safety: no typical loss of coolant accident (LOCA) scenarios • Final design and licensing schedule unclear
PBMR	170	PBMR (Eskom, IDC and BNFL)	GCR	• Helium cooled direct cycle modular design • Coated particle fuel in graphite spheres • Awaiting government approval and funding for demonstration project in South Africa
SWR 1000	1250	Framatome ANP (Areva)	BWR	• Passive safety features combined with proven BWR active systems • Designed for Euro market but U.S. adaptation possible

3.2.2. Criteria Used to Evaluate Nuclear Technologies

Each of the evaluated designs possess unique characteristics that could make any one of them an appropriate choice if a corresponding set of project specific requirements (i.e., CTQs) is used as the basis for the evaluation. As a reminder, CTQ, or “Critical To Quality”, is nomenclature commonly used in the Six Sigma quality evaluation process.[2]

The CTQs of the Texas Gulf Coast end users were established as part of Task 1, and they (along with the investor CTQs discussed below) form the basis for this Task 3 evaluation. A total of 22 CTQs were used to evaluate ten different nuclear generation technologies offered by seven different suppliers. A discussion of the CTQs and corresponding correlation criteria is included in section 3.3 “Methodology” and in section 3.4 “Task Results” as shown below.

2 See Task 1 report for further discussion of the Six Sigma evaluation process.

The Task 3 results indicate that one nuclear technology design, the ABWR (both GE and Toshiba), offers a slightly better fit to the unique CTQs for the TIACT study. However, four other designs, the AP1000, ESBWR, ACR700, and the EPR are closely ranked alternatives each of which, with appropriate final contractual terms, could fulfill the project unique CTQs. Indeed, the ESBWR is clearly of interest to Dominion Generation while the AP1000 and ESBWR are attractive to the NUSTART consortium members. Additionally, TVA is currently conducting a detailed study of the potential for construction of a two-unit ABWR at its Bellefonte site. Thus, current industry activity supports the findings of this study indicating that there are multiple acceptable alternatives. Detailed discussion of the application of these CTQs to the evaluation of all design options is included below in the Methodology section of this Task 3 report. A graphic summary of the Task 3 evaluation results follow in Figure 3.1 below.

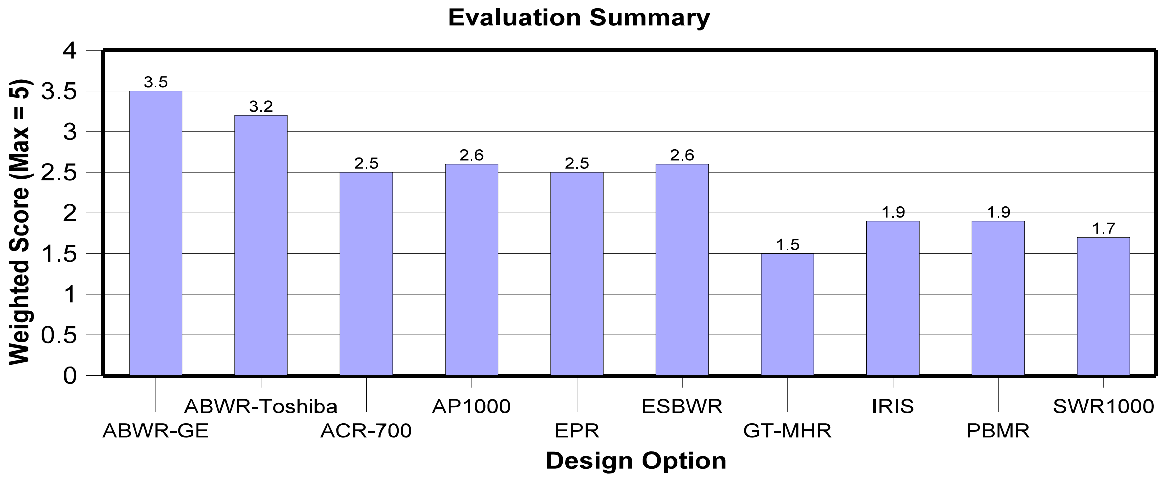

Figure 3.1. Summary of Six Sigma Evaluation Results (Relative Ability to Fullfill CTQs)

3.2.3. Key Evaluation Criteria

Results of the nuclear technology evaluation reflect the weight placed on the more "mature" design alternatives which are either in operation or based heavily upon designs of currently operating plants. This advantage results from the weight given to several of the 'top ten' evaluation criteria[3] which include 'operational experience' and 'U.S. Licensing Status'. A design having positive operational experience as well as a strong licensing status aligned strongly with several CTQs. Conversely, technologies that still require significant final design work and that are without applicable (e.g. full production size) operational experience were not as strongly correlated with the CTQs. Thus, even though a given new technology offers compelling potential for efficient lower cost power generation, the CTQs did not provide overriding credit for such design alternatives. Investor CTQs were key to this comprehensive evaluation process. Return on invested capital (ROIC) and the project debt to equity ratio are two examples of the investor CTQs that carried significant weighting within this task. From an end user and an investor perspective, the more mature designs did well in these evaluations.

3 See Appendix 3A "Task 3 CTQ Analysis Methodology" for additional discussion concerning the 'top ten' evaluation criteria and their linkage to the CTQs.

Executive summaries of the key features and evaluation team comments concerning each technology offering can be found in the Task Results section below.

3.2.4. Hydrogen Production and Desalination-Introduction

The Task 3 evaluation also included a review of current and future hydrogen generation and desalination technologies.[4] This part of Task 3 concluded that the hydrogen generation and desalination technology options do not have a strong impact on the selection of a nuclear generation technology. They may, however, offer economic opportunities. The principal findings of the hydrogen and desalination technology evaluations follow below. The complete text of these evaluations can be found in Appendices 3B and 3C.

3.2.5. Hydrogen Production

The use of nuclear energy to produce hydrogen as a transportation fuel has the potential to play a major role in achieving the goals of a secure, environmentally sound, and economically viable future energy supply. However, there is already a considerable market for hydrogen and the current production of hydrogen in the U.S. alone amounts to about 9 million tons per year. The bulk of this is for use in refining lower-grade crude oil to produce gasoline, and in the agricultural industry for use in fertilizer production. Current hydrogen production is based on fossil fuel sources – 95% comes from steam-methane reforming (SMR). The energy equivalent of the present hydrogen production rate is 100 GWt (about thirty 3000-MWt reactors) at 50 % efficiency. In general the demand for hydrogen is expected to increase at a faster rate than overall energy use, since the grade of crude oil being refined in the US is expected to decrease with time. The production of hydrogen represents a new mission for nuclear energy that is potentially larger than the current mission of emission-free electricity production.

The options for producing hydrogen from a nuclear reactor include both electric (conventional or high temperature electrolysis) and thermal methods (thermochemical cycles). Although there is significant current research interest in developing the more advanced production methods for use with high temperature reactors, only electrolysis was found to be a mature technology ready for supporting a large near-term demand for hydrogen generation. Some observations on the cost of hydrogen from nuclear electricity are summarized below:

- The present market for hydrogen generation is already large ($9 billion per year) and growing faster than overall energy use.
- Figure 3.2 provides the relationship between unique sets of values for the cost of electricity and the cost of natural gas for which the hydrogen produced by electrolysis is equal to the cost of hydrogen produced by natural gas.
- For example when the cost of electricity is $0.04/kWh and the cost of natural gas is $8.0/MBtu,

4 Sandia National Laboratory conducted the hydrogen and desalination technology analysis.

* To denote thermal watts and electrical watts, the subscripts “t” and “e”, respectively, are sometimes used.

then according to Figure 3.2, the cost of hydrogen of $2.50/kg by electrolysis is equal to its cost by SMR.

- For the case where the cost of electricity is as low as $0.02/kWh and the cost of natural gas is $4.50/MBtu, then by Figure 3.2, the cost of hydrogen at $1.50 by electrolysis is equal to its cost by SMR.

- The cost of hydrogen production via high-temperature processes has the potential to be less expensive than electrolysis, but the technology for these options is very immature and unproven.

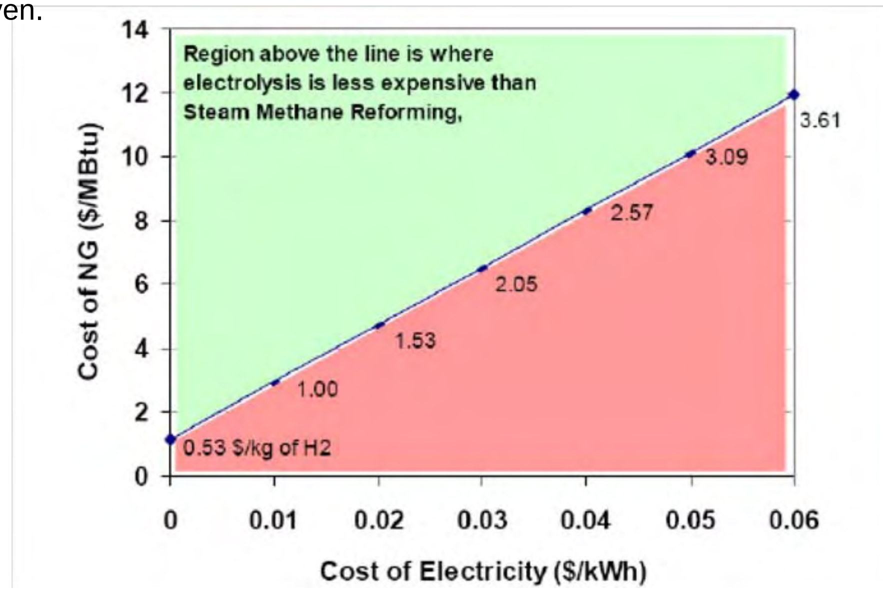

Figure 3.2. Cost of Natural Gas vs. Cost of Electricity Where Electrolysis Becomes Competitive with Steam-Methane Reforming

Thus, if nuclear generation can provide power at competitive costs, there is potential to tap into the existing market for SMR production of hydrogen, which is presently >$5B/yr. See Appendix 3B for an expanded review of the hydrogen generation technology options and their potential linkages with nuclear power.

3.2.6. Desalination from Nuclear

Water desalination will increasingly be used in the future to satisfy growing water demands in areas with limited fresh water sources. Texas may be one area where nuclear power could be used to satisfy increasing energy demands and support water desalination plants. One key objective of this report was to evaluate the potential for desalination linked (directly or indirectly) with nuclear power. Three desalination plants were analyzed in this study to determine the cost of water and various energy use scenarios.

The three plants analyzed were Brackish Water Reverse Osmosis (BWRO), Sea Water Reverse Osmosis (SWRO), and Sea Water Multiple Effect Distillation (SWMED). All plants were analyzed at a production rate of 100,000 m^3/day, plant life of 25 years, 7% interest rate, and electricity cost of \$0.06/kWh. BWRO was found to be the cheapest with a cost of water at \$0.29/m^3. This price assumes low salinity brackish ground water is used. The other two plants purify sea water and are more expensive due to the higher salt content. The cost of water for SWRO is \$0.73/m^3. The thermal distillation process, SWMED, is significantly more expensive at \$1.39/m^3. Typical costs of water in Texas currently can be as little as \$0.08/m^3 for fresh ground water or as much as \$0.67/m^3 for fresh surface water.

100,000 m^3/day BWRO plant needs about 3.8 MW of electricity while the same size SWRO plant needs about 17.1 MW. The use of only off-peak electricity to run the desalination plants was analyzed with the intention of leveling out energy demands. However, running a plant only during off-peak hours leads to higher costs of water (see Figure 3.3). A majority of the cost of water is due to the initial capital costs of the plant, so running a plant only during off-peak hours, leads to less production and higher overall costs. Even if electricity at night is completely free, the cost of water will still be higher for a plant running at half capacity.

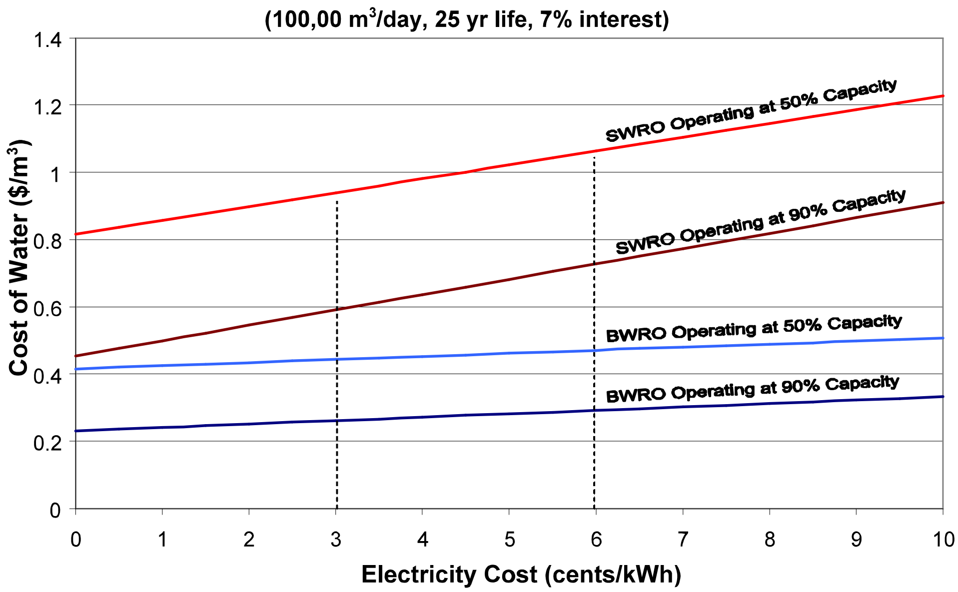

Figure 3.3. BWRO & SWRO Plant Cost of Water

Cogeneration of both fresh water and electricity from nuclear power is a viable option for producing water at reduced costs, and again the reverse osmosis process is the cheapest. A SWRO plant co-located with a power plant can produce water with a 7% cost savings. In areas with large water demand and large electricity demand, building both the power plant and desalination plant at the same location saves capital construction costs and results in 10% lower energy costs for water production.

Finally, in select geographical areas, pumped hydro may prove to be a useful way to use desalination plants to run at full capacity while only drawing off-peak power. Pumped hydro is an energy storage concept that pumps water to a high reservoir during times of excess power. During peak demand times, the desalination plant can use the potential energy of the reservoir to continue to filter water. A BWRO plant will need to get off-peak electricity for about half of the average daily rate in order for the cost of water to be the same. This technology can only be used for brackish water in an area with a 400-500 ft. elevation rise.

3.3. METHODOLOGY SUMMARY

The key process steps followed during the completion of this project task are listed below.

1. Establish technology assessment team;
2. Identify candidate nuclear, hydrogen and desalination technologies;
3. Develop nuclear plant evaluation criteria from the CTQs;.
4. Obtain technical, cost and schedule information on each design;
5. Evaluate each design against the evaluation criteria;
6. Integrate Sandia Hydrogen/Desalination Review;
7. Integrate and present results.

Some of these activities included information exchange with other task activities. Examples of these are:

- The supply of specific financial data by the suppliers for the evaluation of downstream economic tasks (Tasks 6 and 7);

- The input of end user CTQs from Task 1 to Task 3; and

- The iterative input and validation of financial (investor) CTQs from Task 6 to this Task 3.

A brief description of each major process step for Task 3 follows:

3.3.1. Establish Technology Assessment Team

The technology assessment team included highly qualified members from TIACT, EnergyPath Corporation, and Sandia National Laboratories with support provided by others who were part of the larger study project team. These qualifications encompass careers related to chemical technology and applications, advanced nuclear technology, nuclear safety design, and nuclear fuel, as well as nuclear and power market commercial and economic analysis. This ten member team included seven PhDs with an aggregate total of more than 220 years of nuclear or chemical industry experience.

3.3.2. Identify Candidate Nuclear, Hydrogen and Desalination Technologies

The candidate technologies were selected with the goal of including all currently offered designs which could reasonably be expected to be capable of commercial operation within 10 years. Table 3.1 comprises the list for the nuclear technologies. The hydrogen and desalination technology options are discussed in Appendices 3B & 3C.

3.3.3. Develop Nuclear Plant Evaluation Criteria from the CTQs

The development of a comprehensive set of evaluation criteria was recognized early on as a key component of the technology assessment activity. A draft set of criteria was developed by the study team. In parallel with this activity, each of the suppliers was asked to support this effort by providing their recommendations for such a list. All supplier suggestions were consolidated with the initial study team draft to create a data input template for the technology assessment. This template contained more than 150 specific evaluation criteria for use during supplier interview sessions. A sample section of this input data template can be found in Appendix 3A "Task 3 CTQ Analysis Methodology".

3.3.4. Obtain Technical, Cost and Schedule Information on Each Design

Presentation and interview sessions with each supplier were held in one half day increments. The study team met after each interview to consolidate the knowledge gained. Subsequent discussions with most suppliers were needed to clarify or amend inputs.

3.3.5. Evaluate Each Design Against the Evaluation Criteria

The next step was to consolidate the evaluation criteria list such that a correlation (with the CTQs) ranking activity could be conducted. This process is a typical procedure in the world of Six Sigma analysis.[5] Additional validation steps included multiple follow-up discussions with suppliers to verify inputs and to fill gaps. The results of this activity provided the list of the 'top ten' evaluation criteria. These are the criteria judged most strongly linked to the set of 22 CTQs.[6] The 'top ten' evaluation criteria were then applied to each technology option with the resulting evaluation 'scores' tabulated and plotted. The result is shown in Figure 3.1 above.

3.3.6. Integrate Sandia Hydrogen/Desalination Review

In parallel with the activities described above, study team members at Sandia were conducting a detailed review of hydrogen generation and desalination technologies. Related data provided by nuclear technology suppliers was shared with the Sandia team. Their participation in the criteria correlation process helped set the level of evaluation significance assigned to the hydrogen production and desalination options. The results of this effort are found in Appendices 3B and 3C for hydrogen and desalination, respectively.

3.3.7. Integrate and Present Results

Finally, all results are integrated into a single task summary report which is this document.

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5 It will be further discussed in the Appendix 3A "Task 3 CTQ Analysis Methodology".

6 Descriptions and definitions of each CTQ are located in Task 1 (End User CTQs) and in Appendix 6E (Investor CTQs).

3.4. TASK 3 RESULTS

3.4.1. Nuclear Plant Cost Evaluation

The cost to generate nuclear electricity can be categorized as capital, fuel, and operation and maintenance (O&M) costs. In addition, funds must be collected during the operation of the plant sufficient to decommission the plant at the end of life[7]. All of these are discussed here but plant capital cost was the key area of interest during the supplier interview and data collection process. As expected, the suppliers were reluctant to share this information in any detail due to its confidential nature. However, they did provide enough non-confidential information for the team to form some conclusions, using our collective judgment. The cost evaluation presented here is intended to respect confidentiality concerns while providing meaningful results.

Of particular interest was the EPC (Engineering, Procurement, and Construction) cost for a single unit (or multiple units totaling at least 1000 MWe net capacity). In most cases such unit(s) would be, First-Of-A-Kind (FOAK). However, as of the report date, one design (the ABWR) has been built and operated. An additional design, the EPR has been sold and is currently in the early phases of construction. We specifically asked for this information so that we could ensure that the costs of the various technology options were on a comparable basis. To arrive at the total plant capital cost (on an "overnight" basis) from the EPC we used other sources of information for the Owner's Cost, contingency, and, when considering a dual unit project, the savings that can be realized by building two adjoining units approximately one year apart. The process used to determine these cost adjustments is discussed below.[8]

Industry practice is to estimate the owner's cost, which includes those costs associated with project development, licensing, engineering and site infrastructure, at 10% of the EPC costs for a greenfield site. Since the sites under consideration in Texas are existing (or brownfield) sites, we used a lower value, specifically 7%. A value of 5% was considered, recognizing that there is the potential for sharing much of the existing infrastructure. For example, it is possible that one design or another may have an effect on the owner's cost, for example, if the radwaste from the new unit can be processed by the existing facility. (This potential cost saving was not addressed and is not considered to be consequential in the context of the overall evaluation.) We eventually judged that 7% is appropriate given that new environmental regulations will require the use of cooling towers as the ultimate heat sink and that new transmission lines will be needed (see Task 2 report.)

There is substantial cost savings associated with the sequential construction of two units on the same site. One reason for this is that the construction crew and equipment are mobilized only once and that productivity on the second unit is higher. Based upon the different supplier inputs, the cost savings for the second unit are estimated to be 10% of the total overnight cost of the first unit.

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7 Owing to the nature of a nuclear plant, owners do not have the option, available to non-nuclear industrial concerns, to abandon the plant without further significant costs. These costs must be accumulated during the life of the plant - a requirement by the Nuclear Regulatory Commission.

8 To simplify the process and to improve clarity, only the top six evaluated technology options were included in the remainder of this Task Results Summary.

Suppliers were generally unwilling to share the level of contingencies used in preparing their costs estimates, citing the need for confidentiality. We turned, therefore, to other sources of information.

Dr. Geoffrey Rothwell[9], a member of the GEN IV Working Group on Economics and a member of this study team, referred us to work done by the American Association of Cost Engineers International (AACEI) and by the Electric Power Institute (EPRI) in which contingencies are correlated to the project stage. This information was adapted for this study and is given in Appendix 3D.

The adaptation done for this study is to use the level of engineering detail as the key variable that determines the amount of the cost contingency. In the nuclear industry, engineering detail increases with each project stage and it is this detail, if accompanied by vendor quotes, that increases the accuracy and confidence level of the cost estimate.

Moreover, the level of engineering detail can be pegged to its licensing status. For example, roughly 30% of the engineering needed is done in support of design certification (safety system design and analysis.) The purpose of First Of A Kind Engineering programs (FOAKE) are to advance the level of engineering detail further by doing the work needed to prepare manufacturing and construction documents. At one time, it was hoped that the engineering done for the Design Certification and FOAKE programs would together constitute 90% of the total with the remaining 10% being site specific. Completion of the first Construction & Operation License (COL) will help determine the accuracy of this estimate (see Task 4 for the discussion of the COL process).

Based upon these basic understandings and information on the licensing status of each plant design, the following table was created.

Table 3.2. Estimates of Contingencies Applied at Various Development Stages

Development Stage	Contingency	Applicable to Designs
Conceptual	30%	PBMR, GT-MHR, IRIS, SWR1000
Preliminary design (Pre-certification)	18%	ESBWR, ACR700
Safety design (Certification stage)	13%	AP1000
Detailed engineering (FOAKE program underway)	10%	EPR
Finalized design (Constructed or completed FOAKE)	7%	ABWR
As bid for a Texas project	2%	None

9 Dr. Rothwell is a Senior Lecturer in the Department of Economics and in the Public Policy Program, Director of Honors in the Economics Department, and Associate Director of the Public Policy Program at Stanford University. His paper is entitled “Cost Contingency as the Standard Deviation of the Cost Estimate” for submission to *Cost Engineering* June 9, 2004.

There are two other categories, relevant to this study: conceptual design stage (30-50%) and costs as bid (1-2% for a project with a firm price bid and schedule guarantees).[10] This is discussed further in the report for Task 8, "Risk Management Strategy". The purpose of this discussion is to note that, using this approach, the designs can be categorized according to their level of development and design detail, as we have done in Table 3.2. This is in contrast to the historical treatment of contingencies.

Traditionally, adding owner's cost (project specific costs: project development, licensing, site engineering, site infrastructure: roads, warehouses, cooling towers, water intake structures, etc., as well as startup costs and land costs) and contingency to the EPC costs yields an estimate of the total overnight capital costs for a project. The single unit, dual unit, and the Nth of a Kind (NOAK) cost estimates are shown in Figure 3.4. These results are utilized in the Task 6 and 7 economic evaluation activities as well. The overnight cost concept excludes the effects of cost escalation during construction and financing.

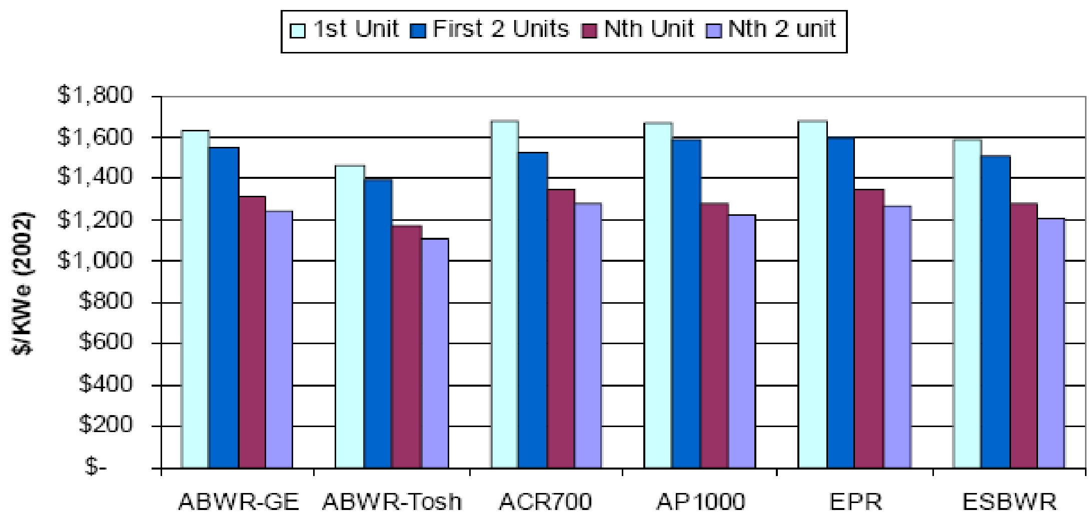

Figure 3.4. Estimated Total 'Overnight' Capital Cost [11]

The cost of unit number five, the much sought after Nth of a Kind plant that suppliers enjoy discussing, is also shown. A learning curve of 4.5% per unit was assumed for all designs. This applies only if it is assumed five single unit projects are built. If dual units are built, much of the "learning" is captured in the cost reduction credited for building two units instead of one.

An additional consideration for cost uncertainty is due to the fact that detailed contractual terms were not provided to suppliers to use as the basis for their cost inputs. No explicit treatment for such costs is provided here other than the overall contingency estimates.

10 For the moment, cost uncertainty due to licensing risk is not treated.

11 To simplify the process and to improve clarity, only the top six evaluated technology options were included in the remainder of this Task Results section.

Historically, final bidding and subsequent contract negotiations have generally resulted in prices greatly exceeding those provided as pre-bid estimates. Examples of such additional costs include site specific scope requirements for a non-standard site..

We, like most observers, are somewhat skeptical about the capital cost estimates provided by suppliers. Energy Information Administration (EIA) of the Department of Energy (DOE) has consistently discounted supplier claims, in our opinion overly so, and currently predicts that total overnight capital costs will be $2000/kW or higher. The MIT study[12] also states that these costs will be at the $2000/kW level but they are willing to concede that such capital costs can be 25% lower and in the game competitively, if suppliers can effect cost savings in several areas including Operation and Maintenance (O&M). The MIT study appropriately asks: what is the likelihood that these savings can be realized?

Our own experience in the industry leads us to believe that cost savings have been realized and that total overnight capital costs are much below $2000/kW. How much below $2000/kW is the pertinent question and this leads us to the discussion of capital cost uncertainty. Those who have the most interest in this subject are those who plan to own or to invest in the plant.

3.4.1.1. Capital Cost Uncertainty

Dr. Geoff Rothwell (see footnote number 8) has researched cost contingency and has found a basis in economic theory for reconciling contingency and the risk premium investors' use when returns are uncertain. Since risk premiums have been extensively researched, conclusions can be drawn about the contingencies placed on projects by cost estimators. Dr. Rothwell has proposed and confirmed that contingencies closely approximate one standard deviation of the lognormal probability distribution of actual costs.[13] In order to get a better estimation of the probability of what the actual costs may turn out to be, we used this approach in our analysis. The following table is extracted from Dr. Rothwell's paper and converts industry stage of development into a standard deviation of the distribution of all actual costs:

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12 "The Future of Nuclear Poer" MIT Dr. John Deutch et al., July 29,l 2003, website: www.mit.edu/nuclearpower .

13 Dr Geoffrey Rothwell, "Cost Contingency as the Standard Deviation of the Cost Estimate" for submission to *Cost Engineering* June 9, 2004.

**Table 3.3. Industry Stage of Development vs.
Standard Deviation of the Distribution of All Actual Costs**

Stage of Development	Standard Deviation
Conceptual Design	30% (from EPRI)
Preliminary Design	18.3%
Safety Design	13.1%
Detailed Engineering	7.0%
As Bid	2% (EnergyPath number)

Further, we are only concerned with the upper bound of actual costs, as all the uncertainty for the supplier is in the direction of bidding sufficiently high enough to avoid accounting losses. By using the contingency costs derived above, we can develop an upper bound of the actual costs once we have specified the level of certainty with which we are comfortable.[14]

The results of this cost uncertainty analysis are shown in Figure 3.5. The capital cost estimates in Figure 3.5 represent a confidence interval of 95%. That is, there is a 95% probability that the supplier's actual quoted costs will fall within the confidence interval shown in Figure 3.5. This also means that we have a 5% probability of receiving quotes that are higher than this confidence interval.

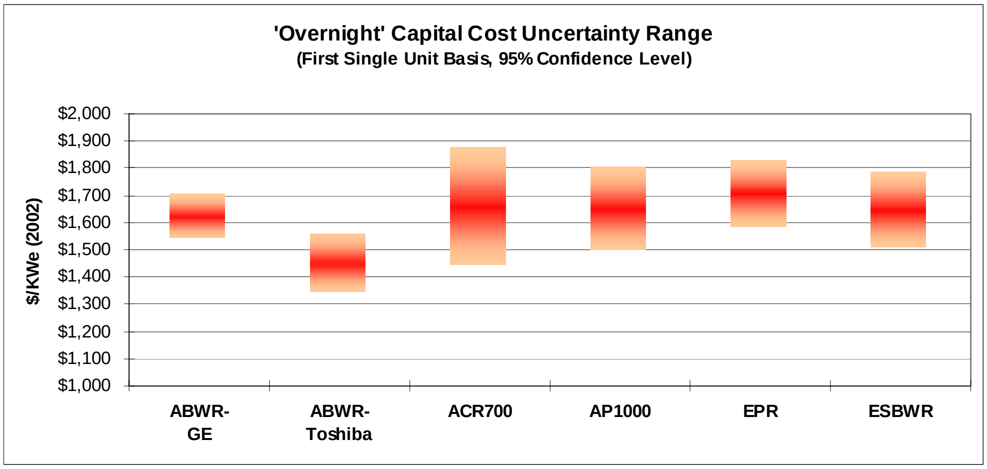

Figure 3.5. Capital Cost Uncertainty

14 This represents a tradeoff: the higher the level of certainty that we aspire to, the higher the upper bound of capital costs. This penalizes the nuclear plant and makes it less competitive with other generating options. On the other hand, if we choose too low a level of certainty then we could find out later that the actual quoted costs are far higher than we expected.

Designs in less developed design stages have a wider range of uncertainty. More noticeable is the fact that the upper range of such inchoate designs is much higher than the corresponding upper bound for more mature designs. These upper bound estimates are taken into account in the financial assessment of the project (Task 6) and seriously penalize those designs in the less-developed stages.

As the newest designs are improved, and more certainty is developed by the supplier, then the contingencies will drop, and the range of capital costs will decline as well.

3.4.2 Project and Construction Schedules

End users and potential investors, the two primary stakeholders, are interested in how long it takes to get a new plant into commercial operation once the decision to proceed has been made. The construction schedule, estimates of which were provided by reactor suppliers, is clearly an important element but not the only one. Consistent with the cost evaluation above, this detailed schedule review focused on the same designs which have greater potential for near term application. The definition of total project schedule is not standard. For this study we have started with the competitive bid specification preparation activity. The next major process steps are: issuance of the Request for Proposal (RFP), supplier bid preparation and submittal, bid review and contracting, submittal and review of the Construction and Operation License[15] (COL), plant construction and finally, startup testing. Our estimate of the total project schedule is shown in Figure 3.6.

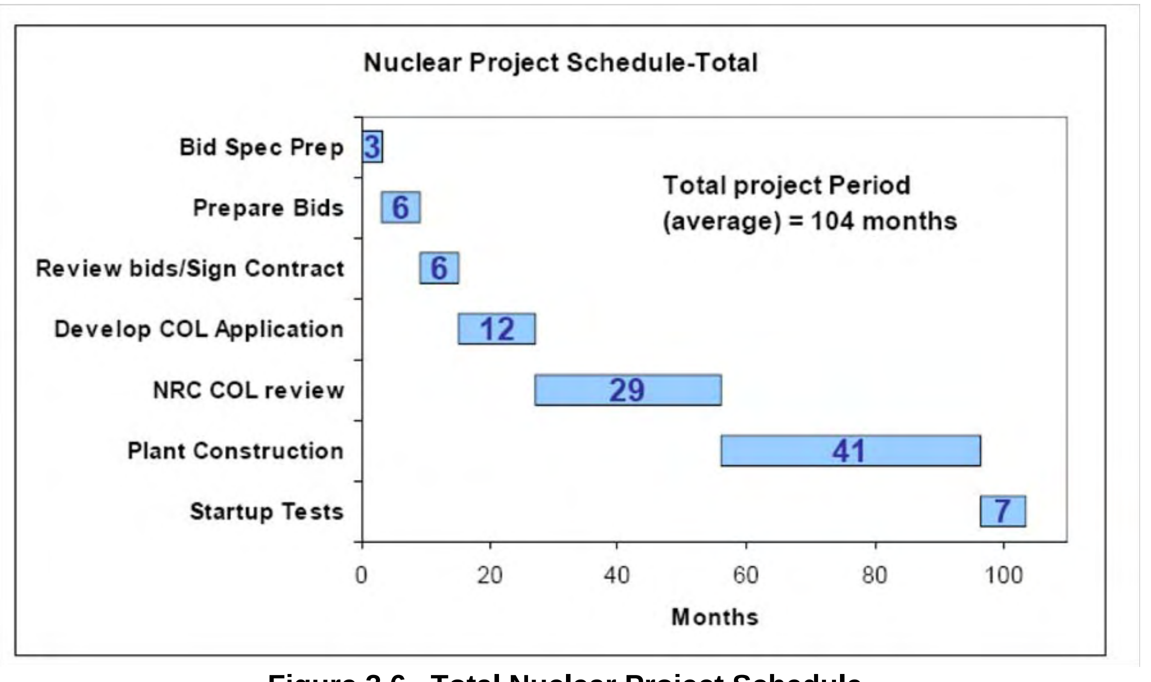

Figure 3.6. Total Nuclear Project Schedule

15 See Task 4 “Licensing and Permitting” for discussion of the COL process.

As can be seen, there are several steps that occur after the decision is made to proceed and well before construction begins.[16] The first of these is to prepare a set of bid specifications. Bid tenders of recent years[17] were based upon the EPRI Utilities Requirements document, which stipulates both the technical and performance requirements for advanced designs. We assume continued use of this process. Therefore, some time must be allocated for the potential buyer or buyer consortium, working with an architectural engineer (AE) that has relevant nuclear experience, to update the requirements, to customize them as appropriate, and otherwise prepare them for use.

The second step is to issue a Request for Proposals (RFP), after which the suppliers normally have six months to respond. It is our recommendation that the RFP require that the COL application be included in the bid package. Recognizing the cost and time involved can be significant, this need not be the complete application but a document that can be used to significantly shorten the time needed to receive a COL from the NRC and start construction.

Another six months is reserved for evaluation of the bids, selection by the review team, and presentation of these recommendations to the potential buyer consortium for approval, and contract negotiations. The time needed for these latter activities, especially contract negotiations, is obviously unique to each case.

Once the design and its supplier have been chosen, the licensing can begin. The COL review is initiated by submitting the application that will be generated using significant input from the bid package. Details as needed to support the review can also be prepared and submitted in parallel with the review. It is hoped that this approach will reduce a significant amount of time from the overall project schedule.

Because there has never been a COL review, the content of the COL application (COLA) is not yet clearly defined. The Nuclear Energy Institute (NEI) has created a COL Task Force whose purpose and goal is to seek guidance from the NRC regarding the content, and expects to submit for NRC review their proposal in the near future.

Even with the content of the COLA clearly specified, it is not clear how long the entire COL process will take. This is especially true for a potential project in Texas where the scope of the COLA may involve both design and site licensing. For our purposes here we assume that the NRC review will take between two and three years. If the COLA is for a “real” project, that is, one for which the decision to proceed to construction has been made, we believe the schedule will likely be closer to two years. Licensing strategies and schedules are discussed in the Task 4 report.[18]

It seems likely that the length of the COL review will be influenced by the design selected and the degree to which it needs further NRC review. The ABWR has a design certification, but a power

16 Start of construction is officially the activities that occur after the construction permit (in the form of the COL) is issued. The actual event is the first pour of structural concrete. Some or all of the excavation needed to get to that point can be done at minimal cost prior to receipt of the COL.

17 International bids conducted by utilities in Taiwan and Finland.

18 See the Task 4 report for discussion of the Inspections, Tests, and Acceptance Criteria (ITAAC).

uprate, upon which the capital cost estimates are based, will need some NRC action. The AP1000 will have its design certification in 2005, so no further licensing of the design will be needed. The ESBWR and the ACR700 are just beginning their certification reviews and it is not known at this time what impact their licensing status will have on the COL schedule for a Texas project. The potential schedule for EPR licensing activity is very uncertain since no schedule is currently in place. Therefore, we have assumed that if selected, the COL schedule for this design would require about 3 years.

The values shown in Figure 3.6 above are the averages of the supplier inputs (if provided) or the consensus of values provided by the task team. The differences in the current licensing status of the various designs will likely yield evaluated differences in the COL time period. And, the construction schedules for First of a Kind newer designs will likely be longer. See the Task 4 "Licensing and Permitting" report for additional discussion on the importance and uncertainties associated with this key process step.

The supplier schedule inputs primarily focused on the construction and startup steps. The variation in construction and startup periods provided by the suppliers is relatively small. This is shown in Figure 3.7.

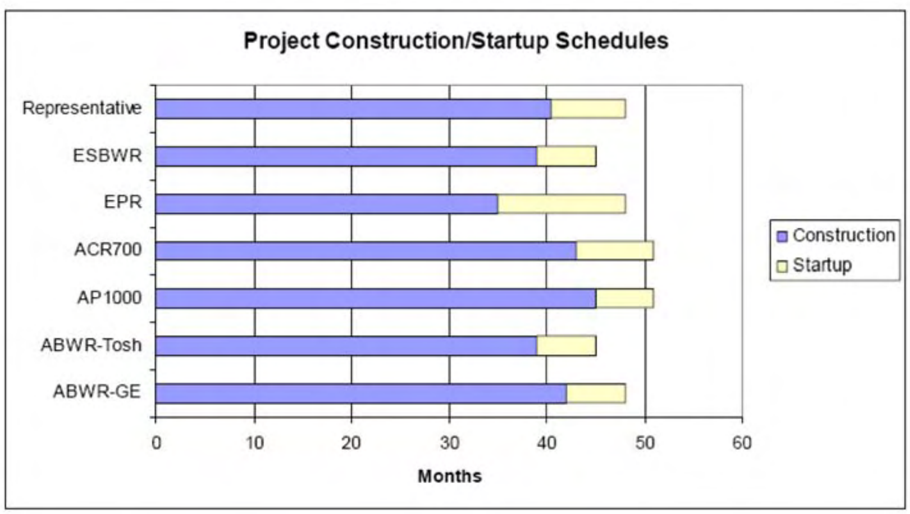

Figure 3.7. Project Construction/Startup Schedules

The contractual aspects of schedule are not modeled here. Depending on specific contract provisions such as liquidated damages for delays, there may be significant differences in final contract schedules.

Nearly all of the suppliers indicated a willingness, under reasonable terms and conditions, to commit to a firm construction schedule with liquidated damages for non-performance. Such a contractual commitment will provide the owners and investors assurances that the plant will be built and completed on schedule, which is a significant change from the contractual practices of the past when large schedule delays were the norm (for a variety of reasons.)

It is well known that the construction schedule is vulnerable to delays that might result from a court injunction imposed as the result of an intervener petition. There are also potential delays that result from the first time use of the Inspections, Tests, and Acceptance Criteria (ITAAC).[19] The schedule above does not reflect that uncertainty. These risks and possible mitigation strategies are discussed in Task 8, Risk Management. For purposes of this Task 3, it is reasonable to expect that these risks are the same for each design (once the design gets to the point of being licensed and otherwise ready for construction.)

3.4.3. Supplier Scope

The willingness of suppliers to offer a total plant scope was also evaluated during this activity. As the supplier interview progressed, it quickly became clear to the study team that a range of enthusiasm existed among the suppliers for such project scope responsibilities. The AECL team stood out among the others in this regard. Early during our meeting, they established an aggressive 'we will take charge and deliver' posture which was noted by all evaluators. This 'face to the customer' was quickly recognized as a key strength for this supplier. A few other suppliers made it known that they had the capability and interest in providing total scope supply. These indications can not be fully validated until corresponding contract terms are approved and world class delivery occurs. However, these examples illustrate what will likely be perceived by prospective plant buyers as a standard basis for future serious consideration. This will be especially critical during the early phases of any renewed commitment to nuclear generation.

3.4.4. Nuclear Technology Evaluation Summaries

This section offers a top-level summary of each nuclear generation technology evaluated by the technology assessment team. Key design features, as well as design specific strengths and future development needs are presented. Perspectives on each supplier's capabilities are also included.

3.4.4.1. The Advanced Boiling Water Reactor (GE and Toshiba)

The ABWR is an evolutionary step in the Boiling Water Reactor (BWR) design series originally developed by GE in the 1960s. It is characterized by a nominal net capacity of greater than 1300 Megawatts Electric (MWe), recirculation pumps that are located within the reactor pressure vessel, a redesigned and improved safety system and significant operational experience for the total system. Currently more than 90 BWRs are operating world wide, including several ABWR units.

GE licensed its BWR technology to Hitachi and Toshiba in the 1960s. Since then,GE, Hitachi and Toshiba built numerous BWR plants in Japan. Beginning in 1979, GE, Hitachi and Toshiba began development of the ABWR which culminated in the two units being built for the Tokyo Electric Company.

The ABWR is the only design evaluated in this study that has operating experience. There are three such units in Japan that have been operating since 1996, 1997 and 2004 respectively, and an additional 3 under construction, 2 in Taiwan and 1 in Japan. The ABWR is also the only evaluated

19 See the Task 4 report for discussion of the Inspections, Tests, and Acceptance Criteria (ITAAC).

design that currently has a Design Certification (DC) certification from the US Nuclear Regulatory Commission (NRC), although the AP1000 will have a DC shortly. This certification is a key measure of design application readiness. A moderating factor for GE's relatively high level of design/operational experience is the recognition that this design is older than the others in the evaluation group. The ABWR's combination of design features may not offer the same level of future capital and operational cost reduction potential as many of the other more recent but much less experienced designs.

Historically, GE, Hitachi and Toshiba have not competed directly with each other for nuclear system orders. All played key roles as part of the supply team with the currently operating units in Japan and all are involved in the ongoing 2-unit Taiwan project. The experience base of GE Energy as a prime supply contractor is strong and consistent with the strength and diversity of its global parent. Further, parent company strength would likely be a risk mitigation asset for investors if GE is selected to supply the next U.S. nuclear system. The study team was given clear indication during our interviews that the GE corporate management team would support such an opportunity. Validating this level of support and the ultimate competitiveness of a future commercial ABWR are two key steps of any future formal proposal activity.

ABWR Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier)

- Over fifteen reactor years of operating experience
- Several units currently under construction in Taiwan and Japan
- Design certified, currently available
- GE's global and diverse business base
- GE indicated potential for turnkey supply and equity participation

Potential Weaknesses-ABWR:

- If power uprate needed this could add to the project's overall schedule
- Future potential for cost reductions may be limited
- GE commitment to future ABWR design availability uncertain (focused on ESBWR?)

3.4.4.2. ACR-700 (Atomic Energy of Canada Limited- AECL)

The ACR-700 or Advanced CANDU Reactor is another design choice that has its origins linked to a significant design, construction, and operational experience base. In this case, 31 reactors of the predecessor CANDU design have operated primarily in Canada, as well as in 4 other countries. It is offered as a single (700MWe) or as a 2 unit (1400 MWe net) plant. The level of technological transition incorporated into the ACR-700 (versus previous CANDUs) is deemed more significant than for the designs discussed above. However, the design basis appears solid with confirmation expected via the U.S. NRC design certification process, which has been initiated. A pre-application process is underway and an NRC Safety Analysis Report (SAR) issuance is expected in October, 2004, and design certification submission is scheduled for March, 2005. Further full scale performance confirmation is desired but not yet committed.

The ACR-700 has many design features which set it apart from virtually all other types of design. It utilizes "heavy water" (D_2O) as the neutron moderator. It allows for on-line refueling of the reactor core, which in this case is called a "calandria". The calandria is a horizontal cylindrical tank containing the uranium fuel bundles that are approximately 20 inches in length and 4 inches in diameter. Pressurized "light water" (H_2O) is used to absorb the heat of the nuclear fission reactions transmitting it to the steam generators which in turn provide steam to the turbine-generators. With the introduction of the ACR700, AECL has changed some of the key features of the CANDU reactor that lead to significant cost savings. These changes are the use of slightly enriched uranium and replacing some of the heavy water with light water as the coolant. This design and its operational requirements are not familiar to most U.S. based nuclear management, operations and regulatory personnel. The unique fuel design will also dictate the need for unique planning, analysis, and infrastructure investment e.g., geologic storage requirements. Despite the cost and other uncertainties noted above, AECL and its U.S. based subsidiary, AECL Technologies believe that capital costs can be significantly reduced to create a compelling economic case for this design.

ACR-700 Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier)

- Aggressive, open and customer-focused supplier
- On-line refueling for higher capacity factor performance
- Re-optimized design appears to have made a significant improvement in costs
- Low total cost potential with reasonable data backup
- Willingness to offer fixed price and more attractive contractual terms

Potential Weaknesses:

- No ACR-700 units sold, under construction or operating
- The ACR (and CANDU) technologies are new to the US nuclear market
- ACR-700 design upgrades a larger perturbation from previous CANDU design upgrades
- No U.S. design license
- No U.S. based project experience of any kind

3.4.4.3. AP1000 (Westinghouse/BNFL)

The Westinghouse nuclear power development legacy is a long one. As a wholly-owned subsidiary of British Nuclear Fuel Limited (BNFL) they continue to build on the Pressurized Water Reactor (PWR) technology they have been refining since the 1960s. There are over 230 PWRs operating world wide with most of them originating from the Westinghouse design lineage. The AP1000 is the current design evolution based upon a scale up from the AP600 design which has received a U.S. NRC Design Certification. The AP1000 has a nominal net capacity of 1117 MWe and is further characterized by significant passive safety features that provide automatic response to accident conditions without electrical motor or other AC powered (i.e., active) systems. Additional features include a nuclear island footprint (the area required for the reactor building) that is the same as that of the AP600. This indicates application of greater space use efficiencies. Although the AP600 was design certified, no plants of this design have been built. The AP1000 received Final Design Approval from the NRC in September 2004 with full design certification expected by the latter half of 2005. This design has been selected as one of the two designs to be supported by the NUSTART Energy (Utility/Vendor) consortium. That activity is currently scheduled to yield NRC review and approval of additional design details in the form of a Combined Operating License (COL) which further validates the design for application at any specific site. In addition, Westinghouse has recently stated publicly that it will be proposing the AP1000 design in China in early 2005, in response to an invitation-to-bid for four units that was just issued there.

The AP1000 passive design features, and corresponding design changes made to increase capacity from 600 to 1117 MWe, are a significant departure from previous design operational experience. Although the design is highly detailed as a result of work on AP600 during the ALWR program, no full scale prototype of this design is operational and final engineering design work has yet to be completed. Thus, near term application of this design would prudently dictate greater focus on contractual performance assurances. This should include schedule margins to accommodate potential First Of A Kind (FOAK) construction challenges. Westinghouse expects six months to one year would be added to the construction of the first plant. As a global player with the largest operational fleet of its technology, Westinghouse has the largest experience base in the nuclear industry-- which now includes reactors that were supplied by ABB and Combustion Engineering.. Thus, their performance history is supportive of a successful design launch. BNFL's acquisition of Westinghouse coupled with BNFL's recent financial performance challenges, have raised questions concerning the potential for additional ownership changes. Fortunately, all AP1000 technology resides solely within Westinghouse. Such issues should be revisited at any time detailed proposal activity is pursued.

AP1000 Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier)

- Extensive global nuclear experience
- First passive plant with NRC Final Design Approval and likely to get US design certification in 2005
- Selected by NUSTART coalition as one of their two designs of choice
- Somewhat smaller nominal plant capacity makes it a potentially better fit in terms of available transmission capacity and expected load growth.
- Indicated willingness to consider equity position in a U.S. AP1000 project
- A potential sale in China in 2005 would accelerate the completion of the design and resolve issues with building and operating the first units.

Potential Weaknesses:

- No operational history with the offered design
- No new units (of this design) currently under construction
- Capital cost claims not supported by recent detailed data
- Uncertain near term corporate ownership structure

3.4.4.4. European Pressurized water Reactor EPR (Framatome ANP- Areva)

The EPR is clearly an evolutionary design emphasizing the application of active safety systems. It is the largest capacity design evaluated under this study with a net rating of approximately 1600 MWe. This design was developed jointly by French and German nuclear utilities and system suppliers working together during the mid 1990s. The two suppliers involved, Framatome and Siemens, have since combined much of their respective nuclear businesses to form Framatome ANP. The combined organization is structured with a strong focus on nuclear generation with what is widely regarded as the most vertically integrated operations of all the suppliers in this market.

The EPR is a robust design featuring four separate trains of active safety equipment, advanced technology digital control systems, as well as state-of-the-art control room design. This reactor system is based on the experience of more than 90 earlier vintage nuclear generating units built by the FramatomeANP parent companies.

The original EPR design focus on European market requirements may have been a factor in the 2003 decision by Finnish electric utility TVO to select the EPR for their next plant. With a planned net output of 1600 MWe this TVO project will be the world's largest nuclear generating unit when completed. Commercial operation for this first-of-a-kind advanced pressurized water reactor is planned for 2009. In addition to the TVO order, the French utility EdF has announced plans for the construction of an EPR. As part of the French licensing process, the French nuclear safety authorities issued their equivalent to design certification in September 2004.

With the final design engineering and country specific licensing underway, this design is seemingly well positioned for expanded application. Although FANP did indicate their intention to submit the EPR to the U.S. NRC for design certification review, no schedule has been established. FANP continues to explore US market opportunities with a strategy that appears to require significant potential customer interest before a commitment is made to invest in the U.S. design certification process. A key criterion in this decision is likely the estimated current and projected future capital cost basis for final design and construction of an EPR in the U.S. The forecasted EPR cost reductions associated with future U.S. market penetration may be deemed insufficient; especially when compared to other nuclear and non nuclear generation investment alternatives.

EPR Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier):

- The next advanced design to be built (for TVO-Finland, startup 2009)
- Global nuclear technology player and commitment
- Strong vertical integration in the nuclear generation market
- Robust plant design with relatively small technology leap
- Extensive global nuclear experience

Potential Weaknesses:

- Although U.S. licensing plan exists, schedule uncertain
- Uncertain capital cost basis (limited data made available to study team)
- US market strategy ill-defined (and perceived as such)
- Not currently linked to one of the lead COL team programs

3.4.4.5. ESBWR Economic Simplified Boiling Water Reactor (GE)

The ESBWR is a 1500 MWe boiling water reactor (BWR) design developed by GE with the support of several international organizations. Its key features include passive safety systems and a core coolant recirculation that uses no pumps. Recirculation of the core coolant is accomplished by natural circulation, a feature of some of the earliest and smallest BWRs. However, natural circulation has never been used at the power levels envisioned for the ESBWR. With this design, a significant amount of active (power consuming) equipment has been replaced with “passive” non-powered equipment and/or safety features.

This design incorporates features of GE's ABWR design as well as features of the passively safe SBWR designed in the late 1980's. The ESBWR offers significant potential for plant design and operational simplification as well as low capital and operational costs. Like the AP1000, the ESBWR has been included in the plans by the NUSTART consortium to complete the FOAK engineering for one of these plants and to pursue a COL application, based upon the design chosen. In addition, GE and Dominion have teamed to obtain a COL for the ESBWR under a DOE cost share program.

ESBWR Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier):

- Indicated design simplicity with safety margins maintained
- Based on scale up of previous SBWR design
- Potential for lower cost evaluation
- Selected by NUSTART coalition as one of their two designs of choice
- Selected by Dominion for COL proposal

Potential Weaknesses:

- Detailed design not completed
- Lack of prototype/design specific operating experience
- Projected cost improvements need confirmation
- Lack of stated plan for future marketing (uncertain available order timing)

3.4.4.6. GT-MHR, Gas Turbine-Modular Helium Reactor (General Atomics)

The GT-MHR consists of 288 MWe modules with 4 units comprising a typical plant configuration. Each module includes a reactor system and a power conversion system. The power conversion system consists of a generator, turbine, compressors, gas recuperator, pre-cooler, and inter-cooler. This design uses helium as the coolant and graphite as the moderator. The fuel is located in graphite blocks in a hexagonal or prismatic form. Hence, this reactor design concept is often called a "prismatic" design. The heat absorbed by the helium is converted to electrical energy via a gas turbine/generator based upon the Brayton direct cycle. The fuel used in this reactor design is also quite different than that for previously described designs. The GT-MHR fuel consists of spherical fuel particles each encapsulated in multiple coating layers, formed into cylindrical fuel "compacts," and then loaded into fuel channels in the graphic blocks.

This integrated design offers the potential for high thermal energy conversion efficiency (~48%). The use of helium gas in this configuration allows the opportunity to provide high temperature to a thermochemical hydrogen generation process. This hydrogen generation process is discussed in greater detail in Appendix 3B of this Task 3 report. The inherent operational characteristics of this design (including the fuel) result in a lower capital cost potential and a reactor system with claimed high nuclear safety performance. General Atomics has a long and successful history of high technology development. However, they do not possess a significant history of reactor project completion as a prime contractor and they did not indicate during our technology review meeting that any such capability development plan was contemplated. Therefore, any future application of the GT-MHR design would involve a supplier consortium concept.

GT-MHR Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier):

- High temperature flexible power conversion capability
- Modular design scale up options
- Potential for TIACT member focus….modular process heat, hydrogen, power
- High thermal efficiency design

Potential Weaknesses:

- Power conversion system development
- Fuel licensing and supply infrastructure
- Lack of commercial nuclear marketing experience
- Corporate strategy not clear
- Component integration
- Availability of this design appears to be well beyond 2010

3.4.4.7. IRIS – International Reactor Innovative and Secure (Westinghouse)

IRIS is a modular pressurized water reactor (PWR) having a relatively small nominal capacity of ~300MWe. The key unique characteristic of this design is its integrated primary system. This means that all of the major hardware components of the primary loop (the flow circuit which passes through the reactor) are contained within one pressure vessel. These contained components include the uranium fuel, steam generators, coolant circulation pumps, and the pressurizer. This differs from the placement of traditional PWR (including AP1000) primary hardware where all the listed components except for the fuel are located outside the primary containment vessel. The benefits associated with this unique IRIS feature include a projected higher level of safety and a smaller total plant size.

The IRIS development consortium is led by Westinghouse and includes a long list of international members. The U.S. Department of Energy (DOE) sponsored this development effort. This design may yield simplified and reduced cost construction if projections hold through the final design, testing, and licensing phases. The smaller size footprint and capacity, as well as the possibility of not requiring emergency response, may make this design appealing in markets and locations not previously thought compatible with nuclear generation. A significant amount of final design, testing and licensing activities remain. The project is currently in the pre-application NRC licensing phase. Design certification is expected to start in 2006 and be completed about 2010. Deployment of the first-of-a-kind IRIS module is scheduled for the 2012-2015 time frame, which may be too remote for this application.

IRIS fits in the marketing strategy of Westinghouse by addressing the market niche of developing countries with limited grid, where a large reactor is not feasible. For larger power applications, the IRIS multi module configuration is an alternative offering limited power increments and avoidance of large money outlays. However, AP1000 is the product being offered now by Westinghouse for these markets and IRIS will be an alternative customer choice later.

IRIS Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier):

- Smaller effective module size and capacity
- Modular design scale up & distributed generation options
- Potential for increased safety and lower cost evaluation
- Strong supplier experience base

Potential Weaknesses:

- Significant design and test activities remain
- Lack of prototype/design specific operating experience
- Confirmation of integrated primary system concept for commercial application
- Longer cycle licensing completion and design application schedule

3.4.4.8. PBMR Pebble Bed Modular Reactor (PBMR)

Like the GT-HMR, the PBMR is a helium cooled, graphite moderated reactor that is capable of providing high temperature, high efficiency power production using a direct Brayton cycle gas turbine – generator. The design is predicated on the AVR (30 MWt) and THTR (700 MWt) prototype pebble bed reactors built and operated in Germany over a 25 year period from 1962-1987. This high temperature gas can also provide the heat source for driving the production of hydrogen via a high temperature electrolysis or a thermo chemical conversion cycle. The PBMR is a modular design having a net capacity of ~170 MWe per module. This study analysis was conducted assuming an “8 pack” site plan totaling ~1360 MWe. This reactor is designed to be inherently safe and passively cooled for all design based accident scenarios. This is possible to a large extent because of the use of a unique spherical fuel element design that reduces the possibility of a core melt accident to the point where the designers argue that a conventional leak tight containment structure is unnecessary. Each fuel sphere contains particles of uranium oxide coated with four layers of carbon and glass compounds. The coated particles are encased in graphite forming spheres about the size of tennis balls.

The PBMR company was formed in 2002 between ESKOM of South Africa, the Industrial Development Corporation, British Nuclear Fuel Limited of U.K. and Exelon of the U.S. to build and market PBMR power plants worldwide.[20] The current plan calls for a demonstration project that consists of the construction of a single modular unit and a pilot fuel manufacturing facility in South Africa. Operation of this first unit is targeted for 2010, but this remains a target until final licensing and project funding requirements have been achieved.

20 Exelon has since withdrawn from the project

PBMR Summary/Key Strengths and Potential Weaknesses:

Strengths(design and supplier):

- High temperature application options
- Modular design scale up and distributed generation options
- Licensing and demonstration project in process
- Simplified system
- On-line fueling for higher potential capacity factor
- Proliferation resistant

Potential Weaknesses:

- Power conversion system development
- Fuel licensing methods, codes and supply infrastructure
- Material life in high temperature environment
- Supplier balance sheet
- Limited operational experience

SWR1000[21]

3.5. DISCUSSION

Any assessment of nuclear generation technologies is a daunting task at best without the use of focused evaluation criteria. The combination of end user and investor requirements (CTQs) and the top ten correlation criteria provided a qualitative means to gauge the ability of each candidate design to fulfill those requirements. The addition of hydrogen production and desalination technology assessments offered another evaluation challenge as well as an opportunity to link and evaluate these technologies.

That designs with the most operational and licensing experience are preferred choices is not surprising given the set of CTQs for this project. We would not necessarily expect the same outcomes for other potential new plant projects in which, for example, end users and private equity investors were not significantly involved. Further, there remain several significant tasks to be completed for this study. Any of these down stream activities could yield results that suggest a review of the Task 3 conclusions is warranted.

Finally, we recognize the limitations associated with data quality. This task and the results achieved did depend, to a large extent, on data provided by suppliers who were aware of the study objectives. The sharing of business strategy, financial data and other potentially competitive information with a third party is not a typical activity for these companies, especially if the expectation is that this information will be used in a side-by-side comparison.. Therefore, we accept that some data provided to this study was adjusted for broad release. The logical validating activity is a formal bid process, the “acid test” for what the cost and schedule truly are. The additional focus will sharpen pencils and expose many vital contractual terms during a well planned and executed bid/negotiation activity.

21 The SWR1000 design is not detailed in this report. The supplier Areva elected not to provide detailed input to the study team concerning this design.

3.6. NEXT STEPS

As noted above, several study tasks follow this Task 3. Downstream inputs from this task include; licensing status information, project schedule information and financial data. The tasks which follow this one include; developing a licensing/permitting plan, identifying potential ownership structures, generating draft pro forma financials, analyzing financing strategies and developing risk reduction strategies.

TASK 4

DEVELOPING LICENSING AND PERMITTING PLAN AND SCHEDULE

TASK 4. DEVELOPING LICENSING AND PERMITTING PLAN AND SCHEDULE

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TASK 4. DEVELOPING LICENSING AND PERMITTING PLAN AND SCHEDULE

4.1. INTRODUCTION

A crucial step in the development of a new nuclear plant, and certainly the most anxiety ridden one, is that of obtaining a license from the Nuclear Regulatory Commission to construct and operate the facility. Potential owners and investors cite the cost and schedule uncertainty associated with the licensing process most often as the major impediment to the deployment of new nuclear plants in the U.S. They do so not because licensing or permitting risk is unique to nuclear plants, which it isn't by any means, but for the reason that its consequences are potentially more severe due to the size of the investment in plant construction (capital costs.) These consequences are more often than not characterized as to be so large as to place a company's very existence in jeopardy.

We are of the opinion that the licensing risk is not as significant as commonly believed and that there are ways to carefully manage these risks. We will propose a few such risk management strategies including one that is a departure from past practice.

The starting point for such a discussion is the description of the licensing options available to the owners of a new project to be built in Texas. Estimates of cost and schedule are provided.

Because of its length and importance, NRC licensing easily sets the critical path for any overall project schedule associated with building a new nuclear plant.

The process embodied in Code of Federal Regulations (CFR) Part 52 permits more than one approach to the licensing of a new nuclear power plant.

Here is the approach that is currently being pursued by the U.S. nuclear industry:

- First, certify a standard plant design.
  Three designs have been now certified and a number of others are in the various stages of certification.
- Secondly, obtain an NRC permit for the specific plant site.
  This is being done in the absence of a decision to proceed to construction and in a way that would allow the eventual construction of any of the designs that are currently certified or are expected to be certified. At present, three utilities are pursuing this via the early site permit program.
- Finally, when a decision to proceed with a project has been made, submit an application for a combined operating license that references both a pre-approved design and a pre-approved site. Note that this step has never yet been taken and there are some major uncertainties associated with it.

This is obviously a conservative approach and one that is appropriate for utilities that are not - for the foreseeable future - in any position to make a commitment to a project. It is expected, however, that this stepwise approach will not be suitable for the Texas Gulf Coast project.

NRC Part 52 does offer other possibilities, as indicated by this excerpt for the regulations:

52.73 Relationship to subparts A and B.

"An application for a combined license under this subpart may, but need not, reference a standard design certification issued under subpart B of this part or an early site permit issued under subpart A of this part, or both".

It is possible, therefore, to submit an application for a COL that includes for approval 1) a site or 2) a plant design not certified (or modification to an existing certified design) or 3) both a site and a non-certified design.

4.2. PRINCIPAL FINDINGS

Permitting a power plant of any kind is subject to schedule delays that increase the financial exposure of the plant owner. This is especially true when it comes to licensing a new nuclear plant with the Nuclear Regulatory Commission. The results of Task 4 describe a risk management strategy that would significantly reduce the uncertainty associated with the NRC licensing process by introducing some new approaches that represent departures from industry practices that have not worked well in the past. Managing this risk is a key concern of potential owners and investors.

4.3. METHODOLOGY

For an understanding of the licensing options available to the applicant (that is, the consortium that will own the new plant) we turned to the law firm of Morgan Lewis, the recognized experts on such matters. Their work appears largely unedited in Sections 4.4 (Licensing Options), 4.5 (Licensing Milestone Schedules) and 4.6 (Costs for Obtaining a COL). A combined construction permit and operating license is called a COL.[1] This information was then used to evaluate three licensing options in terms of their ability to meet both end user and investor CTQs. This evaluation is quickly summarized in Section 4.7 (Evaluation of the Options) and discussed more fully in Appendix 4A. Finally, a process map of the option that scored the highest was developed and subjected to a normal six sigma analysis. This allowed us to systematically identify where the licensing process might break down (the risk points) and to develop action plans that an applicant might take to avoid this pitfalls (risk management.)

4.4. LICENSING OPTIONS

4.4.1. Background

In order to obtain the necessary NRC approvals with minimum regulatory delay and expense, an application to construct and operate a new nuclear power plant should utilize the NRC's procedures for new reactor licensing set forth in 10 CFR Part 52. Part 52 describes the licensing process for obtaining a design certification, an early site permit (ESP), and a combined license (COL).

1 Paul Bessette and Steve Frantz of Morgan Lewis are the authors.

For purposes of this study we have made two simplifying assumptions. The first is that the applicant does not plan to apply for or sponsor a new design certification, but will reference an existing design certification or application for design certification. This is a reasonable assumption to make in light of the technology evaluation done in Task 3 that showed a marked preference for plant designs that are already certified or are in the process of obtaining one. The other assumption is that the applicant does not intend to apply for or rely on an ESP for the proposed site. This is also reasonable because there are no plans that we know of to pursue an ESP for any site in Texas.

Therefore, the two principle licensing options considered here are as follows:

- Applicant submits an application for a COL that references an approved design certification.
- Applicant submits an application for a COL that references a design certification application.

Additionally, for comparison's sake, the following option is also considered.

- Applicant submits an application for a COL that does not reference a design certification or design certification application.

4.4.2. Summary of Applicable Regulations

The applicable regulations for obtaining a design certification and applying for a COL for a new reactor facility are set forth in 10 CFR Part 52. A consolidated summary of the requirements for design certification, as set forth in Subpart B of 10 CFR Part 52, is discussed next. After that, an overview of the requirements for obtaining a COL, which is located in Subpart C of 10 CFR Part 52, is provided.

4.4.3. Requirements for Design Certifications

A design certification constitutes NRC's approval of a standard design for a nuclear power reactor facility. A standard design is certified in a rulemaking proceeding under the provisions in Subpart B of Part 52. In order for a standard design to be certified, the design must be sufficiently detailed and complete to permit NRC to reach a final conclusion on all safety questions associated with the design, except for site-specific features such as the ultimate heat sink. See 10 CFR § 52.47(a)(2).

A certified design can be used at multiple facility sites, or for multiple units of the same standard design at one site, without having to repeat or reopen the NRC's review of the reactor design itself. In particular, under 10 CFR § 52.63 and § 52.79, a COL application may reference a certified standard design, and the certified design is not subject to any additional review or hearings in the COL license proceeding.

The application for a design certification must include the information required by 10 CFR § 52.47. This will primarily consist of a Design Control Document (DCD). In turn, a DCD consists of the following:

- **Tier 1** – Tier 1 of the DCD identifies the top-level design criteria and functional requirements for the standard design. It also includes bounding site parameters (i.e., the bounding values for various parameters for a site for which the standard design is designed to accommodate); interface criteria (i.e., the requirements governing the interface between the standard design and site-specific design features); and inspections, tests, analyses, and acceptance criteria (ITAAC) that must be satisfied to ensure that construction of the as-built plant has been completed in accordance with the certified design.

- **Tier 2** – Tier 2 of the DCD is essentially equivalent to a final safety analysis report (FSAR) for a plant licensed under Part 50, except that Tier 2 does not contain information related to site-specific design features, operational programs, and the licensee's organization. Instead, such information is designated as "COL License Information Items" that must be addressed by the COL applicant in its application. Tier 2 also includes a summary of the probabilistic risk assessment (PRA) for the standard design.

- **Generic Technical Specifications** – These technical specifications essentially have the same form and content as technical specifications that are required to be included within a license.

In practice, the NRC has also required design certification applications to include environmental information related to the standard design, specifically an analysis of severe accident mitigation alternatives (SAMAs) as part of a Technical Support Document (TSD).

Also, as provided in 10 CFR § 52.47(b)(2)(ii), an application for certification of an advanced reactor must identify prototype testing required to be performed prior to granting of the final design certification. We have already assumed that plants under consideration either have a design certification or are in the process of obtaining one. Obviously, prototype testing would not be required for a certified design and any testing required of those designs undergoing parallel licensing would be done as part of that activity.

Following submission of the design certification application, the NRC staff conducts a safety and environmental review. The results of the safety review are documented in a Safety Evaluation Report (SER) and the results of the environmental review are documented in an environmental assessment (EA). Upon completion of these reviews, the NRC staff issues a final design approval (FDA) for the standard design,[2] and the Commission publishes a proposed rule to certify the standard design. The proposed rule provides an opportunity for public comment on the proposed design certification and affords the public an opportunity to comment on the standard design. Following consideration of any public comments and information introduced in the informal hearings, the Commission will issue a final rule certifying the standard design.

Once the NRC has approved a design certification, the information in the DCD, TSD, and SAMA analysis is final and is not subject to further review and approval in individual licensing proceedings that reference the design certification. However, as described in Section VIII of the design certification rules, a COL applicant that references a design certification is allowed to make changes in the DCD, and the degree of NRC review of the changes in the DCD depends upon the nature

2 An FDA represents the approval of the NRC staff, but is not binding upon the Commission itself or upon Atomic Safety and Licensing Boards who conduct certification hearings. As stated in 10 CFR § 52.43(c) and § 52.45(c)(1), an FDA is a prerequisite for a design certification under Subpart B of 10 CFR Part 52.

of the changes.

4.4.4. Requirements for COLs

A COL is a combined construction permit and operating license that contains the conditions for building and operating a reactor facility issued pursuant to the regulations in Subpart C of Part 52. The COL licensing process established in Part 52 allows for a more efficient review process by the NRC than the two-step construction permit and operating licensing process found in 10 CFR Part 50. A COL resolves all of the safety issues associated with design and operation of the plant prior to construction of the plant.

This aspect of the new "one step" licensing process is of significant interest to potential owners and to the investment community. Once the COL is issued and construction starts there is increased assurance that there will be few if any regulatory-driven design changes that would significantly disrupt the construction of the plant.[34] This aspect of the licensing process is a key difference between the way plants were licensed and built 25 years ago.

The application for the COL must include information required by 10 CFR §§ 52.75, 52.77, 52.78, and 52.79. Accordingly, a COL application must contain an FSAR, an Environmental Report ("ER") and Emergency Plans. If the COL application references a design certification, the COL applicant must provide a plant-specific DCD in lieu of an FSAR. The plant-specific DCD is based upon the generic DCD in the design certification and information that addresses the COL License Information Items. Additionally, because issues related to the adequacy of construction cannot be resolved in a COL proceeding, the COL is required to contain ITAAC that must be satisfied prior to commencement of fuel load and operation. See 10 CFR § 52.79. If the COL application references a design certification, the ITAAC must be based upon the ITAAC in the design certification, as supplemented to address site-specific design features. See 10 CFR § 52.79(c).

We note that one concrete reason why certified designs receive higher evaluations is that each comes with an existing DCD and ITAAC. Since these can actually take several years to prepare and have approved, use of existing ones allows a project developer to move ahead with greater speed and less cost.

Upon receipt of a COL application, the NRC staff will conduct a safety and environmental review. The results of the safety review will be documented in an SER and the results of the environmental review will be documented in an Environmental Impact Statement ("EIS"). Following issuance of these reports, hearings on the application will be conducted by an Atomic Safety and Licensing Board ("ASLB"). The ASLB's decision will be subject to review by the Commissioners prior to issuance of the COL.

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3 The NRC can still require changes if it determines that such changes are required for health and safety. One such area of potential changes may include security-related modifications required by revised security regulations.

4 Nor should there be supplier-driven changes since most of the engineering will have been completed prior to the start of construction. The level of engineering detail depends upon the design.

4.4.5. Description of Licensing Options

Option 1: Obtaining a COL That References a Design Certification

As provided by 10 CFR § 52.79(b), an application for a COL may reference a design certification. In accordance with 10 CFR § 52.63, a certified standard design is accorded with "finality," meaning it is not subject to further NRC review or hearings in a proceeding on a COL application that references the design certification. This includes all issues resolved in the design certification, specifically Tier1/ITAAC and Tier 2 information approved in the generic DCD. Accordingly, the NRC staff review of the COL application will focus on plant-specific design issues, siting information, environmental issues, and antitrust information. NRC will not conduct a duplicative review of standard design issues.

This licensing strategy minimizes licensing risk, at least with regard to standard reactor design issues. Nevertheless, there remain numerous matters that must be addressed in the COL that will be considered unresolved and subject to NRC review and public hearing. This includes all plant-specific reactor design issues not addressed in the referenced design certification (e.g. the ultimate heat sink and service water intake structure) and plant specific departures and proposed exemptions from the generic DCD. Further, all COL application information beyond the scope of the referenced design certification, including all site environmental issues, site safety issues (compliance with 10 CFR Part 100 dose criteria), emergency planning, antitrust information, etc. will be subject to NRC review and/or public hearings. The Table of Contents for a COL application is included in Appendix 4B.

Option 2: Obtaining a COL That References a Design Certification Application

As provided by 10 CFR § 52.55(c), a COL application may reference a design certification application. As set forth in Subpart C of 10 CFR Part 52, the NRC staff's review of the COL application will begin after it is filed. By referring to the design certification application for the proposed reactor, the NRC can and should rely on its parallel review of the design certification application. Therefore, the NRC staff review of the COL application should focus primarily on plant-specific design and siting information, rather than conducting a duplicative review of standard design issues. Figure 4.1 is a simplified diagram of this potential licensing process.

Exelon previously proposed to use an analogous process with respect to licensing of the Pebble Bed Modular Reactor (PBMR). Specifically, in a letter to NRC dated May 10, 2001, Exelon proposed to submit an application for an ESP followed shortly thereafter by an application for a COL. Exelon proposed that the NRC review those applications in parallel and that NRC conduct one review of siting issues that would be applicable to both the ESP and COL. NRC would then issue the ESP, which would have finality and foreclose further NRC review in the COL proceeding. In a letter dated August 23, 2001 to Exelon, NRC stated that this process for licensing of the PBMR was conceptually acceptable. Although the process for the PBMR involved parallel ESP and COL applications, there is no fundamental reason why the same type of process could not be used for parallel or overlapping design certification and COL applications.

Assuming the design certification is issued, it will have finality in subsequent license application proceedings, meaning it would no longer be subject to review or hearings in the COL application proceeding. In this case, the certified design would be incorporated into the COL application review and not be subject to additional review or hearings in that proceeding. After issuance of the design certification, the NRC staff's review and ASLB hearings in the COL proceeding would be limited in scope to plant-specific issues.

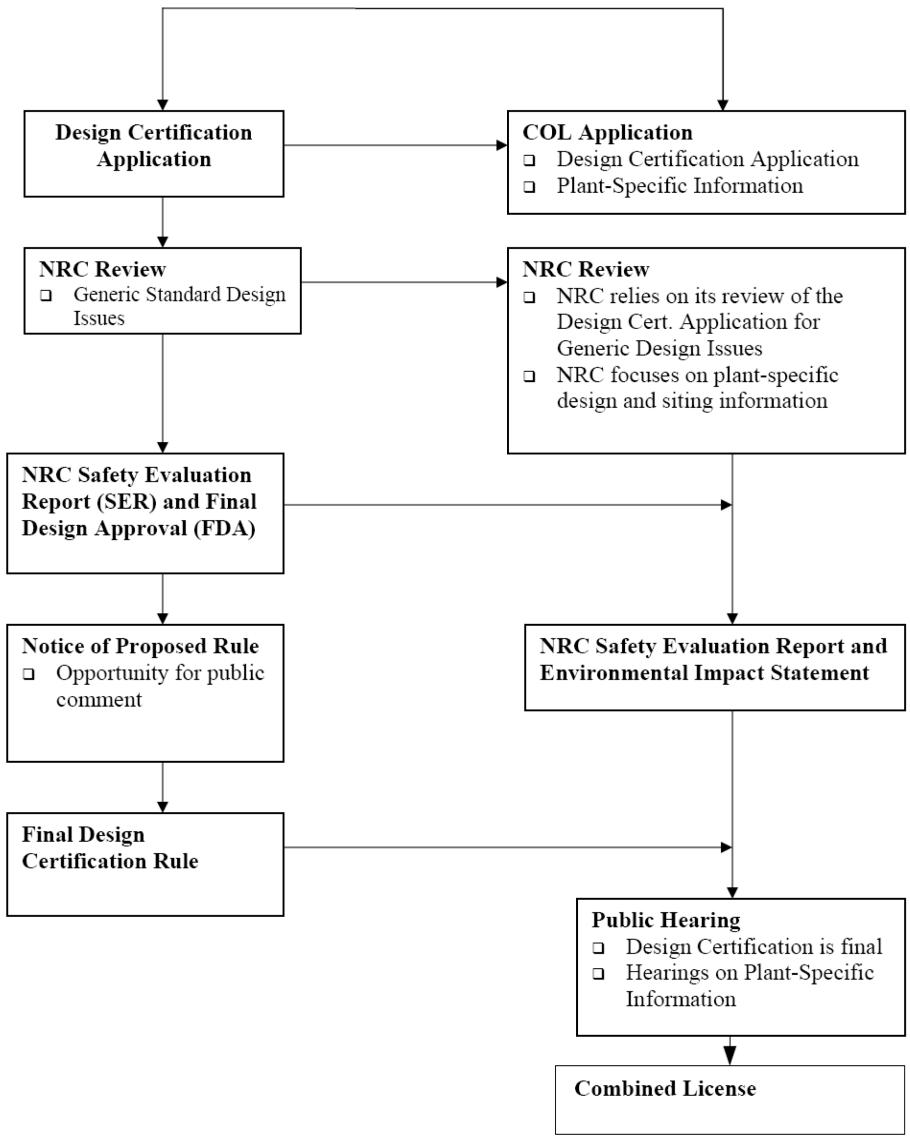

Figure 4.1. Process For Obtaining A Design Certification and COL in Parallel

However, referencing a design certification application is at the "risk" of the COL applicant. For example, if the NRC does not approve the referenced design certification application, the COL applicant would not have any finality for that portion of the design covered by the design certification application, and would need to seek individual approval of that portion of the design in conjunction with the rest of the COL application. In contrast, if the design certification application is approved prior to issuance of the COL, it would then have finality in the related COL proceeding and foreclose any further NRC review and hearings on that portion of the design. Further, if the NRC does not approve the referenced design certification application prior to approval of the COL, approval of the COL would be delayed, perhaps significantly, until issuance of the design certification.

Option 3: Obtaining a COL That Does Not Reference a Design Certification or Design Certification Application

If the COL does not reference a design certification or design certification application, the COL applicant would need to seek approval for all aspects of the reactor plant design in conjunction with the rest of the COL application. Accordingly, all issues in the COL would be subject to NRC review and hearings. This would require a significant expansion in the scope of applicant and NRC resources necessary to prepare and review the COL.[5]

Final Note: Obtain an Early Site Permit (ESP) before Submitting the COL Application

This is a fourth potential option and it is the licensing strategy being pursued by NuStart and Dominion. It was ruled out here for several reasons. First, it was judged that an ESP program would add significantly to the overall schedule. This would put it squarely at odds with the end user CTQs, which indicate a strong desire to have a new plant into operation at the earliest possible date. Another reason is that the tollgate strategy described in Task 8 focuses the time and resources of the management team upon resolving the project's key financial risks (EPC cost and delays during construction) during the initial phase of the project, when the ESP program would be expected to take place.

4.5. LICENSING MILESTONES SCHEDULE

4.5.1. Introduction

An estimated schedule of milestone events associated with preparation, submission, and NRC review and approval of a COL is attached. The milestone schedule assumes that the COL references an approved design certification and is generally based on NRC estimates and experience to-date with ESP applications.

4.5.2. Pre-Application Review

In order to establish an acceptable scope and schedule for the COL application, the applicant should meet with the appropriate NRC Staff to discuss their commitment to obtaining a COL and a framework for establishing the reviews of the applications.

5 If this licensing strategy were selected, the applicant would most certainly team with a reactor vendor, who would be largely responsible for supplying the additional reactor design data.

In particular, it will be important for the applicant to inform the NRC of the schedules for submission of the application to enable NRC to arrange to have sufficient resources to review the applications. In a document addressing future licensing activities attached to SECY-01-0188, *Future Licensing and Inspection Readiness Assessment* (October 12, 2001), the NRC recognized the potential for significant new licensing activity. The NRC noted that Staff decisions regarding the prioritization of new reactor licensing activity will depend, in large measure, on the number and timing of industry decisions to pursue new licensing activities, and that review schedules are dependent on resource availability. Thus, the NRC has urged the nuclear industry to be as specific as possible about its plan and schedules, so that it can plan and budget its limited resources.

Currently, the NRC is reviewing three applications for early site permits and one application for design certification. Additionally, the NRC is involved in several pre-application reviews of design certifications, and two consortiums are seeking funding from the Department of Energy to apply for a COL. None of the design certification or ESP applications would directly authorize construction and operation for a nuclear plant. Since NRC will likely give priority to applications that involve actual construction and operation of a new plant, it should be possible for a COL applicant to obtain sufficient NRC resources to support review and approval of its application provided that the applicant supplies NRC with timely notice of the application.

Additionally, if the licensing strategy involves referencing a design certification application, it will be essential for the COL applicant to provide the NRC with timely notice of their intended actions. During the pre-application review, it will be important for the applicant to provide the NRC Staff with sufficient preliminary information that aids the NRC in understanding the dual-track or overlapping review process set forth in this paper. As the design certification and COL applications will be reviewed in parallel, it will be important for the NRC Staff to agree to avoid any duplication of effort in order to assure timely consideration and approval of the design certification application in time to benefit the COL review.

4.5.3. Design Certification Application

The NRC has estimated that the review of a certification application for a new reactor design would take 3½ - 5 years from the time of submittal until the granting of design certification.[6]

The licensing process associated with referencing a design certification application depends on issuance of the design certification before approval of the COL. Thus, the critical path would be issuance of the design certification. Therefore, to avoid an extended COL licensing process, the applicant should ensure that the design certification application is submitted at least one to two years prior to submission of the COL application. Alternatively, it should be possible to complete NRC review of and hearings on the site-specific issues in the COL proceeding while NRC's review of the design certification application is still ongoing. The ASLB, however, would need to be persuaded to defer litigation of standard design issues in the COL proceeding pending issuance

6 SECY-01-0188 (October 12, 2001), attaching *Future Licensing and Inspection Readiness Assessment* (September 2001), at p. V-4. The longer estimate assumed hearings on the design certification, which is no longer allowed.

of the design certification in order to avoid duplicative reviews of the standard design issues.[7] After issuance of the design certification, the standard design would have finality and would not be subject to hearings by the ASLB in the COL proceeding, and the NRC should be able to issue the COL promptly thereafter.

4.5.4. COL Application

The NRC has estimated that the time to issue a COL that references a design certification and an ESP would be 27 months. A COL that references an ESP only is expected to take 33 – 60 months, depending on the uniqueness of the reactor design. See SECY-01-0188. NRC has not provided an estimate for a COL that references neither a design certification or ESP. These estimates could be longer, depending primarily upon the number of interveners in the hearing on the COL, their sophistication, and the number and complexity of their contentions. And while the NRC has recently revised its rules of practice on hearings in 10 CFR Part 2 to allow the use of informal, legislative-type hearings rather than formal, trial-type hearings that NRC has used in past licensing proceedings, the risk of significant delay in the hearing process is reduced but not eliminated. There is also still some uncertainty regarding the COL review process that cannot be anticipated. Specifically, the NRC has yet to receive and review any COL application submitted under 10 CFR Part 52. To date, the NRC has only reviewed operating license applications under 10 CFR Part 50 and ESPs under Part 52. Furthermore, in the wake of the September 11, 2001 attacks, the NRC is still reviewing the entire scope of security and safety requirements applicable to nuclear reactor sites, and it is possible that NRC may impose new design requirements to enhance security. Such regulatory changes would need to be taken into account by any COL applicant.

4.5.5. COL Milestone Schedule

The attached milestone schedule reflects key steps in the COL licensing process, assuming the COL references a design certification. The milestone schedule was prepared based on recent industry experience with ESP applications and NRC licensing process estimates. As noted previously, NRC has estimated that a COL application will take from 27 – 60 months, depending on whether it references a design certification and/or ESP, and the uniqueness of the design.

Assuming the COL references an approved design certification for a light water reactor (LWR) but not an ESP, we estimate that the COL could be approved within 36 months. This schedule assumes that the NRC will review environmental and safety issues in parallel. The critical path, however, is the issuance of a final environmental impact statement (FEIS) for the proposed facility and site. NRC issuance of the three pending ESPs is scheduled to take a minimum of 33 months. While there should be some improvement in this process for subsequent environmental reviews, we would not expect significant reductions in this schedule given the broader scope of issues included in the COL than the ESP.

We would not expect any significant increase in this schedule for a COL that references a design certification application, assuming such application is submitted sufficiently prior to the COL

7 While deferral of such action is well within the discretion of the Chairman of the ASLB, interveners in the COL proceeding (if any) are likely to argue strongly against such a deferral.

application and assuming that NRC is willing to rely on its review of the design certification for resolution of standard design issues referenced in the COL.

If the COL does not reference a design certification, we would expect NRC approval to take substantially longer, due to the expanded scope of plant-specific design issues that must be considered as part of the COL.

4.6. COSTS FOR OBTAINING A COL

The costs of obtaining a COL will include the costs of performing site investigations, preparation of the COL application, and review by the NRC (NRC's review costs are assessed as fees to the applicant). For the purpose of this analysis, we have not included other costs that are typically incurred by a COL applicant but are not directly associated with a COL application (such as costs of development of detailed design documents, procurement of the site, procurement of components, and site preparation).

The costs for obtaining a COL that references a design certification or a design certification application should be similar but somewhat higher than the costs for obtaining an ESP. It is our understanding that the existing ESP applicants have estimated the costs of obtaining an ESP at approximately $10 million. Therefore, it is reasonable to estimate that the costs of obtaining a COL would be equal to or less than $15 million.

If the COL application does not reference a design certification or a design certification application, the costs for obtaining the COL would be higher due to the need to develop a full safety analysis report (FSAR) and to pay for the cost of NRC review of the FSAR. As a result, it could be expected that the cost of obtaining such a COL would be substantially larger. A reasonable estimate might be $15 to $20 million (exclusive of the cost of development of the detailed design).

4.7. EVALUATION OF THE LICENSING OPTIONS

The three licensing options were evaluated using criteria based upon end user and the set of investor CTQs introduced in Tasks 1 and 3, respectively. Since it will be the investors[8] who must provide the development capital to the prepare COL and pay the NRC fees for its review, we gave significantly more weight to their needs as expressed by the CTQs.

The results of the evaluation are given in Table 4.1. The licensing option that ranks highest is the one that includes the use of plant for which there is an existing Design Certification.

8 As noted many times in this study, the proposed plant would be located in ERCOT, a fully deregulated market. The owners of the plant therefore would need to provide or secure development capital to fund the development phase of the project that includes the preparation and review of the COL application. Thus the owners are properly viewed as investors, especially since the development capital is at risk.

Table 4.1. Evaluation of Licensing Options

Options*	Ranking
Option 1: Reference existing DC	100
Option 2: Reference DC application	76
Option 3: COL includes design licensing	40

* Note: All options include site licensing as part of the COL application, that is, does not reference an ESP.

The reasons for this not surprising outcome can be traced back to the two largest concerns of investors: loss of capital and a return on invested capital (ROIC) that is less than expected. Loss of capital would occur if the COL were never obtained, as might be the case if the COL application (COLA) included licensing of a new design or if the COLA referenced an ongoing certification effort (less likely but still possible.) A diminished ROIC would result if the entire COL process, from preparation to final NRC approval, were to take longer than expected. Use of an existing design certification builds more predictability into the schedule.

More details on the evaluation are given in Appendix 4A.

4.8. SPECIAL CASE: ABWR POWER UPRATE

The capital costs of the ABWR are based upon a design that has a power level of about 1440 MW net. This compares to the 1326 MW rating of the certified design. So the question is how best to obtain NRC approval of the uprate?

If the decision is to amend the ABWR design certification, it may take as long as 5 years to do so. This is obviously a long time but before the proposed changes were submitted, the NRC would need to establish the amendment process itself via rulemaking. This rulemaking is currently not in the works. (At one time, the NRC had issued a Notice of Proposed Rulemaking on how to amend certified designs. This, however, has been withdrawn.)

There are, fortunately, two other ways. The first is to submit a COL application that includes a proposal to uprate the ABWR. As mentioned earlier, a COL applicant that references a design certification is allowed to make changes in the Design Control Document. If approved, the uprated ABWR would be licensed only for the Texas project, not generically. Regardless, any changes to the DCD would be subject to an NRC proceeding.

Yet another way would be for GE to separately submit an application to uprate to the ABWR using pre-approved methods in much the same manner as it would for an operating BWR. This option needs to be explored further.

4.9. UNIQUE ISSUE: ANTI-TRUST INFORMATION IN THE COL APPLICATION

The NRC requires that the applicant submit anti-trust information 9 months prior to the submittal of the COL application. The list of information required is imposing and includes information that one would normally find in an Integrated Resource Plan done by regulated Investor Owned Utilities (IOUs). Here are a few examples:

- "Most recent peak load and dependable capacity at time of system peak for each of the next 10 years for which information is available. Identify each new unit or resource."
- "Estimated annual load growth for each of the next 20 years or for the period applicant utilizes in system planning." (What system?)
- "Applicant's six (or fewer if there are not six) lowest industrial or large commercial rates for firm electric power supply and indicate the portion of the charge attributed to bulk power supply."

As can be seen this is the type of information that a regulated IOU would normally generate in the normal course of its business but does not apply at all for independent or merchant generators such as the proposed nuclear plant. Moreover, asking an independent generator operating in a competitive wholesale and retail market to supply this information strikes us as inappropriate.

The Nuclear Energy Institute has asked the NRC to provide an exception for merchant generators from the requirement to submit this antitrust information. In response, the NRC has asked the Department of Justice (DOJ) to advise them on this issue. Because there are no near-term proposals for new nuclear merchant plants this issue has been relegated to the back burner by both the NRC and DOJ.

This is an important issue for a project developer since it adds significant time to the development phase of the project while simultaneously increasing the amount of development capital that must be raised and postponing the day when revenues can be generated to repay it.

4.10. SIX SIGMA ANALYSIS OF THE LICENSING PROCESS

4.10.1. Introduction

Like other processes, the one for COL licensing can be analyzed and improved using six sigma techniques. If this sounds presumptuous, let us hasten to add that we are not talking about the process by which the NRC reviews and approves the COLA. The NRC "owns" that process and must take into account not just the needs of the applicant[9] but also the needs of many stakeholders, including state and local governments and members of the public. Indeed the needs or CTQs of owners are rightly weighted less than those of the public and their need for continued health and safety.

For our purposes here, we define the COL process as that which starts when the owners make the decision to proceed and begin preparation of the COLA; and ends with the formal approval of the NRC of the COL. The NRC review and approval is considered to be a subset of this overall process.

9 The consortium that will own the plant or the project development team that represents them.

We will look at those steps over which the applicant has control or influence.

4.10.2. Six Sigma Methodology

There are many six sigma techniques that are available to analyze and improve processes. By far the most frequently used are:

- "DMEDI"[10] or "Design for Six Sigma" which, as the names imply, are used to create a process where none exists and for which there is no data; and
- "DMAIC"[11] which is used for existing processes and for which there is statistically significant data on how it performs in terms of meeting the customers' CTQs.

The COL process is a mixture of these two, actually. On the one hand, the COL process is new and untested. Indeed, a COLA has never been prepared and even the contents of the COLA are unknown at this time.[12] There is, therefore, no hard data on how such a process will work and what results it will produce. Applicants are legitimately concerned about the amount of financial risk to which this uncertainty subjects them.

On other hand, the NRC part of the COL process is specified by law and only its implementation is open to change. Since this is such a major part of the overall COL process, we will use DMAIC and substitute soft data (estimates, judgment of experts, extrapolation from relevant data) for hard data, since the latter obviously doesn't exist.

4.10.3. Results

The detailed results of the DMAIC analysis are presented in Appendix 4C. In the next few sections, we will highlight a few of the important elements of this analysis and summarize the key findings.

4.10.4. Defining the problem

The problem is defined in terms of how the process fails to meet the needs of the customers. The process is defined here as that by which a project development team:

- Raises development capital
- Selects an engineering firm to assist it
- Selects a plant design and site
- Identifies the licensee and operator of the plant
- Prepares the COL application
- Supports the NRC's review of this

10 DMEDI stands for Define, Measure, Explore, Develop, and Implement.

11 DMAIC stands for Define, Measure, Analyze, Improve, and Control. Please refer to Appendix 4C for a summary explanation of this methodology.

12 NEI has assembled a task force that is currently preparing a guidance letter to the NRC in which it will propose the outline, content, and required information. It is expected that this will be submitted to the NRC by the end of 2004.

- Participates in public hearings
- Receives and holds the COL in its name when approved by the Commission

The customers for this process are the investors who have provided development capital that funds the COL activities. What they want from this process was captured in the investor set of CTQsthe least risk of the overall project being delay; the least risk of the COL itself being delayed; and the shortest amount of time to get COL. Less important is the actual cost of getting the COL. This clearly suggests that investors want the project development team to get the COL "done right the first time" and need to know that the project team has budgeted sufficient resources to do so.

The simple fact that a process has inputs and outputs is illustrated in Figure 4.2. There are at least two sources of inputs to this processthat by the project developer and that by the nuclear industry as a whole. The desired output is a COL that is issued on a timely and predictable schedule and for the amount budgeted (around $20M exclusive of engineering costs.)

To use six sigma terms, the "opportunity" is to submit a COLA to the NRC. The process produces a "defect" when the desired output is not realized which in this case means the budget and schedule for the COL is exceeded.

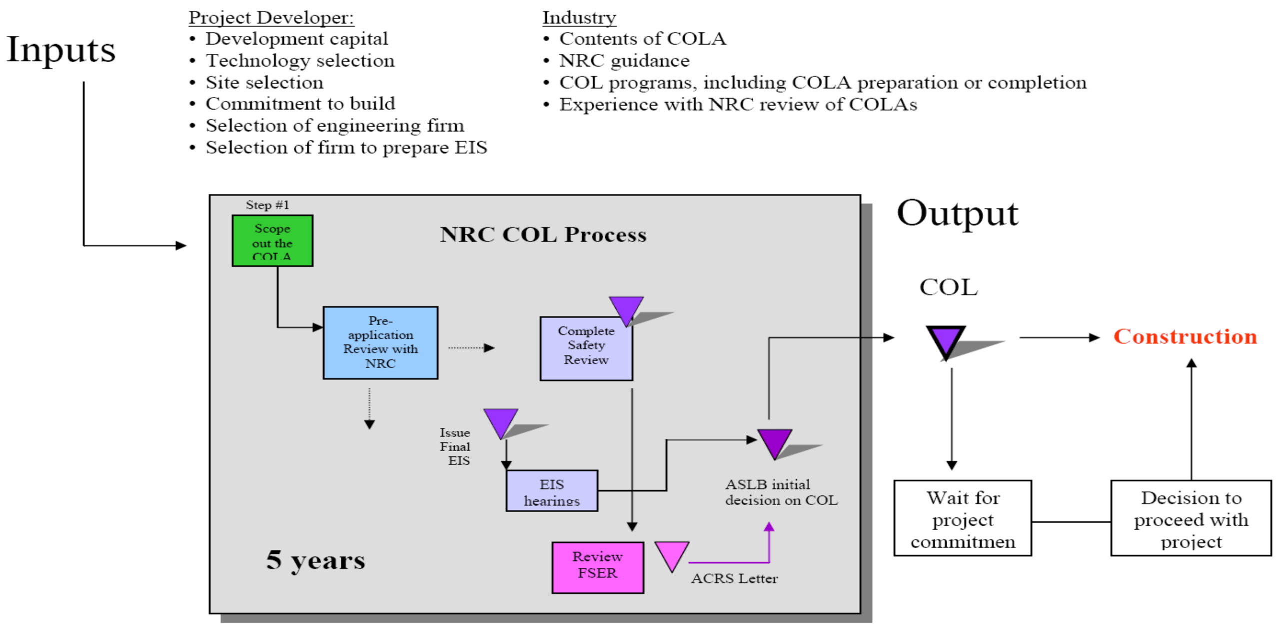

Figure 4.2. The Project Developer's COL Process

4.10.5. Measure Potential Failures and Analyze

Since a COLA has never been submitted to the NRC, there are no statistics that measure how many defects occur per opportunity. Unless there is a massive build out of new nuclear plants, it is unlikely that there ever will be statistically significant data. For this kind of process, we estimate how the process might fail to produce the desired outcome. The first step is to look at the process map in detail and identify the “critical Xs”[13] by which we mean that part of the process that may potentially fail and have a significantly negative impact on the desired outcome. The process map with Critical Xs identified is given in Figure 4C-3.

The next step is the analyze these to establish those that have the most impact on the CTQs of investors (the customer as represented by the project developer.) The appropriate tool here is the FMEA (or Failure Modes and Effects Analyses). Some of the FMEA is given in the Appendix 4B.

4.10.6. Improve the Process

The results of the FMEA suggest that there are actions that the project developer can take to increase the likelihood that the COL will be issued on schedule and budget. In retrospect, some of these are obvious. A few suggestions, however, would not have been forthcoming with out the six-sigma analysis and one in particular is a significant departure from the historic way the nuclear industry has approached public issues.

Here is the list of action items that a project developer can take to successfully manage the portion of the COL process that it controls:

- Form a consortium that intends to build a plant, as opposed to one that seeks to "position for the future."
- Involve the owners of the available sites at the outset and bring them into the consortium. (Since the sites are not pre-licensed, their cooperation is essential.)
- Eliminate the anti-trust requirement in the COLA.
- Use only a Certified Design, if at all possible.
    - Therefore, ascertain before the process begins that plants with Certified Designs have costs that meet the financial needs of investors. This is a very serious endeavor that may include conducting a bid competition.
    - If these plants are not competitive now, see if the suppliers are willing and able to take action to reduce costs.
- Support NEI's COL Task Force
- Hire a strong project manager and utilize proven project management tools
- Hire the best environmental firm to prepare and defend the EIS.
- Develop a strong community outreach program. Implement as soon as decision is made to proceed with COLA. Budget properly for it.
- Hire firms with licensing (legal and engineering) expertise that have a strong Washington presence to closely follow the proceedings.

We will discuss the highlighted items in the next section.

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13 Critical Xs refer to the equation F(X1, X2, X3…Xn) = Y where Y is the desired outcome of process F(x) and X1, X2, X3…Xn are inputs or steps in the process. The critical Xs are those that have the most influence on the outcome.

4.11. DISCUSSION OF RISK MANAGEMENT STRATEGIES

The perception of many, especially those in the investment community, is that the licensing process is fraught with risk and that the main culprit for this is the NRC. We would be foolish to argue that the risk is overblown but we are encouraged, as the result of doing this Task 4, that the risk is more manageable than otherwise thought. This is particularly the case if the project developer concentrates on the elements of the process that it, not the NRC, controls.

There are four distinct risks that collectively constitute the "licensing risk," as given below. Steve Frantz and Paul Bessette of the law firm Morgan Lewis provided the study team with a perspective on each of these risks.

1. The risk that the NRC staff won't keep to its COL schedule despite the best efforts of the project developer.

   Perspective: This risk is deemed to be small on the basis of experience that shows the NRC has been good at monitoring and keeping schedules. This has been especially true of the license renewal applications. To minimize this risk, it should be the goal of the project development team to prepare a complete and thorough application.

   An exception would be if the COLA references a plant design undergoing Certification that is a significant departure from Light Water Reactor designs. In that case this particular risk will be understandably higher since there is the potential for schedule delays arising from the need for new tests or from recommendations by the NRC staff to include new or modified design features.

2. The risk that an intervener(s) with standing will raise numerous admissible contentions during the COL review process.

   Perspective: Given the nature and scope of this project, it is likely that such contentions will be brought forward. However, the new regulations in Part 52 set the bar high with respect to what new issues can be introduced. Also, the COL process will not be a regulatory hearing in which testimony, briefs and cross-examinations can bog the review down for months. This risk is therefore judged to be small.

A delay in receiving the COL would certainly result in financial pain for the consortium but would not be catastrophic for the companies involved.

3. The risk that the ITAAC process will unravel.

   Perspective: Although we are encouraged that the NRC is conducting its business in a disciplined manner, the ITAAC process has never been used and there is simply no way make a judgment about the size of this risk. If there were a dispute about whether or not the as-built plant conforms to the ITAACs, a meeting between the NRC staff and the constructor would need to be held to resolve the differences. The timing of this meeting determines the financial consequences. If the hearing is held after the NRC has approved fuel load, chances are that the project would not be held up (there would be 6-9 months to resolve the issues before the next NRC action, issuance of the COL.) On the other hand, if the need for the hearing delays approval of fuel loading, then the impact will be day-for-day and have significant financial consequences. This is certainly one area where the management team can control the risk by careful planning and execution

4. The risk that interveners with standing will ask a judge to halt the project who then issues a temporary restraining order while the issues get sorted out. This is the consortium and the investment community's worst nightmare.

   Perspective: As already noted above, the new Part 52 regulations have a high bar for determining what new issues can be introduced. If a judge is sympathetic enough to consider the interveners claim, it is likely (though not certain) that these will be resolved quickly and without the need for a temporary restraining order, out of the recognition that huge amounts of money are at stake. Indeed, history tells us that once a project goes to construction, it is highly unlikely that a judge would stop it. This risk is deemed to be small.

   Although it is likely to evoke strong opinions to the contrary, our finding here is that the overall licensing risk is small. It is, moreover, much smaller than the investment community perceives it to be, although we recognize that perceptions do count.

Strategy #1: "We're for real"

Form a consortium that commits to construction prior to submitting the COLA.

A consortium that is intent on building a plant will be full engaged in the COL process. A privately financed consortium using development capital and without recourse to ratepayers will be doubly engaged. This engagement and motivation is the single most important determinant in achieving a successful outcome to the COL review.
Moreover, the NRC is likely to allocate its scarce resources to a COLA that represents a construction project and possibly to commit to a shorter review schedule. A two-year schedule may be possible after the NRC has some experience under its belt but it is more realistic to assume that the schedule for the first application will be three years.

A commitment to construction obviously needs to be proceeded by a compelling prospectus backed by an unassailable business case. That leads us to…

Strategy #2: "Plants with fuzzy costs need not apply"

Before submitting the COLA, select a plant design for which the supplier has made a contractual commitment to the price and schedule.

As discussed in several places in this study, end user and investor CTQs strongly favor the use of a plant that has a Design Certification. However, the economics of these plants, especially the capital costs, may not meet the financial requirements of the consortium.[14] If this proves to be the case, then there are two actions that can be taken to address this concern. The first is to encourage the suppliers to reduce their costs within the framework of the Design Certification or other easily accomplished licensing action (see the earlier discussion on the ABWR Power Uprate for example.) If the suppliers are unwilling or unable to do so in a timely way, then it may be necessary to fund and conduct a bid competition in which all interested suppliers would respond to a bid specification that included the project terms and conditions. The supplier selected and the consortium would agree to be bound by the terms of the proposal at a later date–the consortium would execute a contract with the supplier once the COL is issued (or before if appropriate) and the supplier would agree to build the plant for the price indicated in its proposal.

Estimates of development capital needed would include sufficient funds for this activity.

Strategy #3: Plagarism is a Best Practice"

Make full use of industry programs. For example, NuStart and Dominion have both received grants from DOE to prepare and submit COLAs. This preparation and perhaps some NRC review will be completed as the Texas project moves to the starting line.

Strategy #4: "Who will join hands with me?"

Commit to an early and extensive public outreach program.

We think this is the most important of the risk management strategies, especially in terms of addressing the needs of the investment community.

It is our opinion that lack of commitment to an actual construction project creates a potentially fatal flaw in the efforts to get a COL because it does not focus on building consensus with stakeholders in the project, including the local community and its leaders.

We have observed how difficult it is for merchant generators to permit combined cycle units because of the active involvement and concerns of stakeholders. The successful of these merchant generators have engaged stakeholders very early in the process, even before the first press release that announces the project. They work relentlessly to inform the public and to build consensus among the stakeholders, including diverse organizations–trade unions, business associations, environmental groups, health groups (the Heart and Lung Foundation for example) the NAACP, and so on.

We strongly believe this is an essential element in a successful COL effort because it will bring to bear the support of many groups especially at the public hearings and neutralize the efforts of the dedicated opponents of nuclear power.

14 This is discussed fully and in detail in Tasks 6 and 7 of this study in which the uncertainty surrounding these costs is factored into the overall economics of the project.

4.12. EXTERNAL RISKS

Before concluding this discussion on risk management, we need to make note of some external risks that are small in probability but large in consequence. These are:

- The introduction of new and significant technical information, an example of which would be the discovery of a new earthquake fault during the site inspections.
- An accident or other event that occurs at another nuclear plant, the consequence of which is negative publicity or a call for new regulations.
- The intervention of national or even international organizations that are ideologically opposed to nuclear power.

4.13. SUMMARY AND CONCLUSIONS

Permitting a power plant of any kind is subject to schedule delays that increase the financial exposure of the plant owner. This is especially true when it comes to licensing a new nuclear plant with the Nuclear Regulatory Commission. However, it is the judgment of Morgan Lewis and a key finding of this report that the licensing risk is small. Moreover, it is much smaller than the level of risk perceived by investment community, although we recognize that these perceptions do count.

Managing the licensing risk is a key concern of potential owners and investors. A finding of this report is that the overall risk can be managed by first dividing it into four distinct elements each of which is then amenable to proactive measures. Industry practices in this area have not always worked well and so we recommend some new approaches that represent departures from these practices. Of particular note is a community outreach effort modeled on the best practices of independent generators. This outreach to both local and national stakeholders would begin almost immediately (during Tollgate #1 as described in Chapter 8) and would provide the consortium with crucial feedback regarding the extent and nature of both support and opposition to the project. This information could potentially head off or defuse opposition to the project during the licensing process.

Finally, the recommended licensing strategy is to submit a COL application that references a certified design or a design undergoing Design Certification. **An Early Site Permit program is not recommended**. These findings are consistent with both the end user CTQs, which favor an expeditious project schedule; and the tollgate approach which demands that resources of the project management team be focused upon resolving the project's key risks during the time when an ESP would otherwise take place.

TASK 5

ESTABLISH THE OWNERSHIP STRUCTURE OPTIONS

TASK 5. ESTABLISH THE OWNERSHIP STRUCTURE OPTIONS

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TASK 5. ESTABLISH THE OWNERSHIP STRUCTURE OPTIONS

5.1. INTRODUCTION

A nuclear plant project represents several significant investment challenges. First, there is the sheer financial size of the project, on the order of $2B per unit. Secondly, financial markets in the aftermath of the Enron collapse take a much more conservative approach to power plant projects and will require a higher percentage of equity investment. If 50% is required, then the owner or owners will need to provide about $1B of equity. During the period of construction, this $1B of negative cash flow dilutes the company's earnings with all attendant affect on stock valuation. Finally, in the absence of good risk management, this $1B will be considered at risk. Loss of such an investment would jeopardize the financial health of all but the very largest companies.

This obstacle can be overcome by crafting ownership arrangements that spread the equity investment and risk among several parties. The Contractor will develop several options for evaluation.

This evaluation includes the effects of different ownership arrangements on the project pro forma (please refer to Task 6), expected to be slight and owner's evaluation (please refer to Task 7), expected to be significant. The intent here is to find an ownership arrangement that balances the needs (CTQs) of end users and those of potential owners.

The Contractor has the responsibility of contacting potential owners and equity investors, including power companies, suppliers, and end users, to ascertain what it would take for them to invest in the potential Texas project. This information is used in formulating the recommended ownership arrangement that will help move the project forward.

There are two characteristics of the business case to build a new nuclear plant in Texas that are unique in the industry. One is the involvement of large industrial electricity users and the other is that the plant would be located in ERCOT where both the wholesale and retail markets have been deregulated for several years. These two characteristics shape the nature of the ownership arrangements.

Large industrial users in the petrochemical industry are responsible for initiating and co-funding this study. Many have expressed their view in both private and public that additional nuclear capacity to offset the state's dependence on natural gas will be essential to Texas's economic vitality. As described in Task 1 of this study, chemical companies are subject to global competition and have limited opportunities to pass along rising energy costs to the customers.

It is not surprising therefore that some of these large industrial companies have expressed an interest in taking an equity position in a new nuclear plant in order to secure a long term supply of electricity characterized by cheaper and relatively certain costs.

Because the plant would be located in a deregulated market, it would be owned by an independent generator without recourse, as regulated utilities have, to a steady supply of customers and guaranteed revenues. It would be privately financed in the sense that shareholders of the venture, as opposed to ratepayers, would be at risk for the costs. Private financing of a $2B project, even one backed by long term power purchase agreements (PPAs), represents a sizeable investment, cash flow drain, and risk for one company alone to undertake.

So we begin consideration of ownership arrangements with the obvious–a consortium of end users.

5.2. PRINCIPAL FINDINGS

There is widespread support for building more nuclear power plants in Texas, but a basic question is "Who will own it?" The answer to that question must take into account the two characteristics of this endeavor that are unique in the industry. One is the involvement of large industrial electricity users and the other is that the plant would be located in ERCOT where both the wholesale and retail markets have been deregulated for several years. These two characteristics shape the nature of the ownership arrangements.

The results of Task 5 recommend that such arrangements be based upon a version of the ownership model used with great success by the Finnish utility TVO for its new nuclear plant (construction to start in 2005.) It further recommends the creation next year of a development corporation (This corporation will for convenience be called “Texas Gulf Coast Nuclear, Inc.”) to begin the work of marshalling the widespread interest in a new plant and transforming it into an ownership consortium.

5.3. THE “TVO” MODEL

A nuclear plant that is owned almost entirely by end users is what we call the “TVO” model. The thought here is to replicate in the U.S. what the Finnish utility Teollisuuden Voima Oy[1], or TVO for short, has achieved.

The company’s public information states“Teollisuuden Voima Oy was founded on January 23rd, 1969, by 16 Finnish companies from the industry and power sectors…TVO is a privately owned electricity generation company, owned by Finnish industry and power companies. The company supplies electricity to its shareholders at cost.”[2] For this reason TVO’s annual income statement shows zero profit and that makes TVO, as we enjoy saying, a non-profit corporation. Shares of ownership have changed hands over time and now include even foreign investors (EdF of France for example) but the basic ownership structure remains the same.

TVO’s existing nuclear capacity currently consists of two 835 MW units located at its Olkiluoto site on the Baltic Sea. TVO has a dedicated staff that operates these two units (as opposed to “out sourcing” plant management.) The Managing Director of TVO is directly responsible to the Board of Directors, which includes proportional representation from the various owners, for the safe and economic operation of the plant. Olkiluoto units 1 and 2 are the very model of operating success; they have the global industry’s highest capacity factors, shortest outages and most productive staff.

1 Voima Oy translates in English as “Power Company”.

2 Source: TVO website at http://www.tvo.fi/104.htm .

This successful arrangement is being continued and extended to more participants with the addition of TVO's newest power plant (Olkiluoto 3).[3] More than 60 Finnish companies will participate in the investment and have a share of the electricity to be produced by the new unit. Many of the new investors are municipal utilities. A map of Finland showing the locations and names of the owners of Olkiluoto 2 are shown in Figure 5A-1 of the Appendix 5A.

A member of EnergyPath was in the TVO offices a few days immediately after the company publicly announced its intentions to seek government approval of Olkiluoto 3. In the aftermath of that announcement, the phone figuratively rang off the hook with inquiries from manufacturers and local utilities wanting to get in on the action, so to speak--"invest for electricity" as it is phrased in the ownership agreements. The significance, aside from it being a ringing endorsement for nuclear power, is that these organizations were willing to make a hard commitment even before the government approved the project.

In order to assess the implications of various ownership structures, we will employ five key criteria(1) organizational issues; (2) NRC's financial requirements for licensees; (3) size of the investment for each potential owner; (4) financial issues; and (5) the required rate of return on investment for each ownership structure.

With all this in mind, let us consider the first possible ownership arrangement for a new plant in Texas.

5.4. OPTION 1: END USERS ARE THE OWNERS

5.4.1. Description

In this option, the new plant and the business venture it represents would be 100% owned by end users, primarily from those industries that are energy intensive and sensitive to energy costs as this case for much of the petrochemical industry in Texas. The output from an advanced nuclear plant ranging from 700 to 1500 MWs would be captured at cost.

A new business entity, which we will dub "Texas Gulf Coast Nuclear, Inc." or (TGCN) would be incorporated in the state of Texas and governed by a Board of Directors that represent the owners. After completing the initial startup activities common to all new companies, the TGCN Board would hire an experienced management team that would be responsible to the Board basically for obtaining a Construction and Operation License (COL) and financing. We will discuss the development effort in more detail in Section 5.6. The development activities are the same for each option.

5.4.2. Organization

As its role changes over time from that of project developer to construction manager and ultimately

3 Finland's nuclear regulatory body STUK is currently reviewing the plant design for Olkiluoto 3, which is Framatome's EPR or European Pressurized Water Reactor rated at 1600 MR. Commercial operation of the plant is scheduled for 2009.

plant manager, the management team would itself evolve, changing personnel and skill sets in the course of doing so, and add construction, engineering, licensing and operational people to its staff as approved by the Board. An alternative to operating the plant is to hire the services of companies with experienced operating staff. For example, if the unit were to be located at an existing site, the company that manages the operating units could provide staffing to operate and maintain the new plant under a services agreement with TGCN. Or, another experienced nuclear operator such as Nuclear Management Corporation or Entergy Nuclear could operate the plant under contract with TGCN.

Other necessary functions such as legal counsel, financial management and accounting, and public relations would reside in another part of the organization, reporting to the Board through separate management.

A simple organization chart might then look like this:

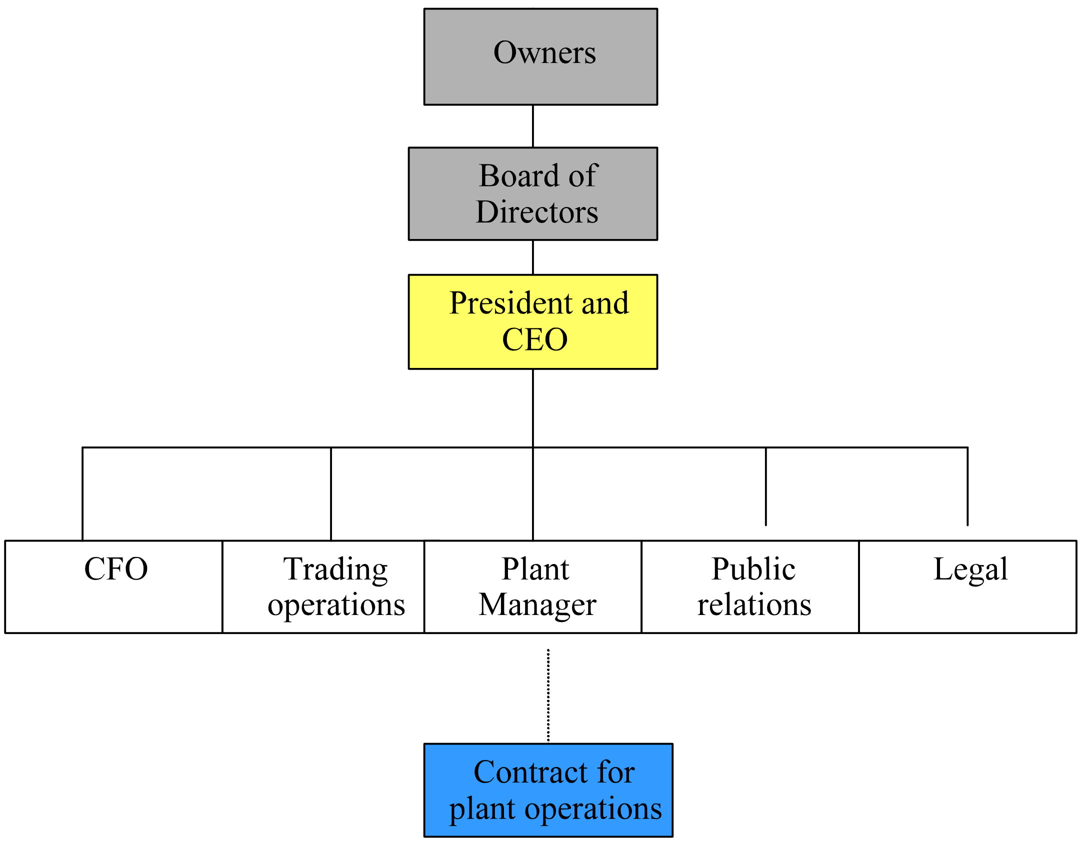

Figure 5.1. Organization Chart of a Nuclear Plant with End Users as Owners

One function not normally associated with nuclear plant operations is that of buying and selling electricity or “trading.” As a stand alone business it will be necessary for TGCN to have a trading organization that sells the unused output of the plant, buys electricity for delivery to customers when the plant is down for scheduled refueling and maintenance, hedges deliveries for the unplanned plant outages, and interacts with other market participants such as a Qualified Scheduling Entity, other Load Serving Entities, the transmission provider, and ERCOT.

5.4.3. Satisfying the NRC's Financial Requirements

As the holder of the plant's operating license, TGCN must meet the NRC's financial requirements. TGCN must provide reasonable assurances that it has the resources (budget) to properly budget for the safe operation of the plant and to decommission it at the end of its life (60 years for an advanced nuclear plant.) An NRC discussion of the applicability of these requirements to an independent generator such as TGCN is provided in Appendix 5B. The key points are:

- Non-electric utility applicants (TGCN) must submit estimates for the total construction costs and annual operating costs for each of the first 5 years of operation of the facility and identify the source of funds to cover such operating costs.

- The use of an external sinking fund to cover the future cost of decommissioning is not available to independent generators unless there is some form of government or owner guarantee. Other options are available but it seems the one most favored is an up front payment into a trust fund. It is important to know that this payment could be about $150M, an amount that potentially erodes the economic attractiveness of the project.

For an ownership consortium that consists of only large industrial end users, the first requirement is easy to satisfy. An ownership agreement modeled after that used by TVO would require a contractual annual contribution by each owner toward the projected costs for the upcoming year (fuel, operations, maintenance) as well as its portion of the debt coverage. If an owner fails to meet this requirement, its share of the electricity would be sold on the market to make up for the missed contribution.

The second requirement is more challenging. In order to avoid making the decommissioning prepayment, TGCN could resort to options that require guarantees. A corporate parent guarantee for the entire amount is acceptable. The NRC does allow use of an external sinking fund in combination with the corporate guarantee. Finally, the NRC does make an exception to the decommissioning requirement if TGCN has a government guarantee and can assure the NRC at what point the needed funds will be available.

For follow on work, we recommend that a survey be taken of end users who expressed interest in partial ownership on the feasibility of their corporate entity providing the financial backstop for its share of decommissioning funds. Another follow on task would be to assess the feasibility of the U.S. government providing such a guarantee, especially in the context of overcoming a potentially significant obstacle faced by the so-called "first movers."

5.4.4. Size of the Investment in Plant Construction

We learned from our end user survey that large electrical loads at major chemical facilities cluster between 125 and 250 MW. This represents in round numbers between 10% to 20% of the plant's output. We would expect, therefore, to need between 5 to 10 (or more) end users making investments of this order. Thus, if the construction costs prove to be $2.0B, and loans account for 50% of that, a typical investment by an end user would be between $100M and $200 M, paid out over a period of 4 years.

This is not an unreasonable investment for chemical companies who typically sink much more into their own facilities and in many instances have invested in cogeneration plants costing that much or more.

Whether or not it is financially attractive to make an investment in a nuclear plant is another question and one that will be taken up in Tasks 6 and 7.

5.4.5. Financing Plant Construction

The financial terms and conditions available to this group of owners is an interesting question. To be specific, how much debt will lenders be willing to put into this project and what is the cost of that debt.

As usual, it all depends.

Given the unpleasant experience many lenders have had with merchant power plants, it is likely that anything more than 50% debt can be ruled out.[4] But will lenders provide even that much debt and at what rate? On the positive side is the fact that all of the output is in effect sold and the owner's agreement provides a steady inflow of cash. On the negative side is the potential for the chemical industry (for example) to take a down turn thereby reducing the need for electricity by many owners. In a worst-case scenario, some of the owners may default on their obligations to Texas Gulf Coast. Lenders will want to know how these risks can be managed and hedged. (We discuss these issues more fully in Task 8, Risk Management.)

5.4.6. Return on Invested Capital Needed for this Ownership Group

One of the more intriguing aspects of end user involvement is that they are not as risk adverse as Investor Owned Utilities. Thus we would expect that an ROIC that is acceptable to this group of owner/investors would be a point or two less. This in turn makes the project's economics look better, all else being equal.

4 Our discussions with the investment community confirm this.

5.5. OPTION 2: END USERS, MUNICIPAL UTILITIES, AND POWER COMPANIES

5.5.1. Description

Based upon our conversations with large end users in Texas, we believe that it is unlikely at this point in time that a new nuclear plant will be 100% owned by industrial end users. One very good reason is that the output of nuclear plants currently available are between 1150 and 1500 MW[5], much too large to be used up by only manufacturers. So let us consider the ownership arrangement that comes closest to the "TVO Model."

In this arrangement, ownership includes municipal and investor owned utilities as well as some prominent end users. This ownership arrangement is very similar to that for South Texas Project (STP) except for the fact that the ownership does not include large industrial end users. The owners are:

- Austin Energy, The City of Austin 16%
- AEP Texas Central Company 25%
- City Public Service of San Antonio 28%
- Texas Genco LP 30.8%

As can be seen, two of the four owners are municipal utilities and the other two have parents that are Investor Owned Utilities IOUs (Industrial Owned Utilities) such as American Electric Power and Texas GENCO, formerly the generation component of Reliant Energy, Inc.

There are currently ownership changes in progress. In March 2004, AEP announced that it had sold its shares in STP to the Cameco Corporation. Cameco is a Canadian firm with businesses associated with the nuclear fuel cycle and owns, more importantly for this discussion, 32% of Bruce Power a partnership that currently operates six nuclear power plants with a total capacity of 4,700 megawatts. However, Texas Genco and City Public Service of San Antonio exercised their rights of first refusal by purchasing AEP's 25% share.

Additionally, Texas Genco is in the process of being sold to a private equity investment group that includes The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P. and Texas Pacific Group. The resulting ownership interests in STP are anticipated to be:

- Austin Energy, The City of Austin 16%
- City Public Service of San Antonio 40%
- Texas Genco LP 44%

STP Nuclear Operating Company operates the plant for the owners, who share its energy in proportion to their ownership interest.

It is easy to conceive of an ownership consortium that includes the current owners of STP and a

5 We are not discounting the ACR700 whose capacity is 700 MW but believe to be economic it will require a two unit project or 1400 MW of capacity.

few prominent end users from the petrochemical industry. For discussion purposes, let’s say the shares are as follows

Table 5.1. Possible Ownership Shares

Owner	Share	MW
Industrial end users	15%	210
Municipal utilities	50%	700
Generation Companies	10%	350
Private Investor Groups	25%	250
Total	**100%**	**1400**

This is a reasonable scenario. For end users, 210 MWs represents the load for one or two typical end users. Also, 700 MW is less than the current shares of STP owned by Austin Energy and City Public Service of San Antonio. It would represent only a modest increase in the generation capacity they already own and probably represents two or three years of normal load growth.

It is also quite possible to increase the share of the Generating Companies if the circumstances warrant, as it would if it were to host the plant at one of its sites.

5.5.2. Organization

The organization of TGCN in this option would be the same as before with one very important difference. One of the owners would likely be the owner of the host site, including STP and Comanche Peak. Since this owner already holds an NRC operating license and experience managing nuclear units, it would not be necessary to create and train a staff from scratch or to hire an outside operating company to run the plant. It also simplifies contractual arrangements in that it will be easier to execute an agreement between the new owners and the site owner for use of the site (a lease, for example.)

5.5.3. Satisfying NRC Financial Requirements

To meet the NRC financial requirements for decommissioning when there are multiple owners is complicated by the fact that the parties would never be jointly and severally liable for decommissioning costs. Therefore, each owner will need to meet the NRC requirement in the way most appropriate for its situation. For example, a municipal utility may be able to meet the requirement through use of an external sinking fund since they are exempted from deregulation and retain the authority to enter their costs into a rate base. A private equity investment group, on the other hand, would need to resort to another means including the creation of a decommissioning fund for its share of the costs.

5.5.4. Size of the Investment in Plant Construction

The number of potential owners in this option is more than in Option 1. This consortium would not only be broad but diverse as well, a positive in terms of meeting NRC financial requirements and protecting Texas Gulf Coast from periodic changes in ownership. The size of the investment per investor would not exceed $250M, an amount that appears manageable for this list of prospective owners.

5.5.5. Financing Plant Construction

This ownership consortium should be able to attract favorable financing terms and conditions. On the positive side, municipal utilities have rate making authority, a predictable and captive customer base, and can issue tax-free bonds for purposes of financing plant construction.

5.5.6. Return on Invested Capital Needed for this Ownership Group

This ownership group is diverse in many respects and that includes their desired ROIC.[6] It is estimated that an aggregated ROIC of about 10% would be required to attract this group of owners.

5.6. OPTION 3: ADD NUCLEAR INDUSTRY INVESTORS

This option builds upon the previous one by adding companies who have significant business interests within the nuclear industry. These are:

- **Reactor Suppliers**
  GE, Westinghouse, and AECL have all expressed a willingness to make a limited investment (<10%) in the plant probably in the form of postponed payments for project scope, cashing out when the plant begins operation. This would help reduce the negative cash flow especially during the last 2 years of the construction period when it is most pronounced.

- **Suppliers of Uranium and Enrichment Services**
  CAMECO, whose interest in owning nuclear plants has been discussed, is a strong possibility. Also, the US Enrichment Corporation (USEC) seems to have similar interests.

- **Foreign Investors**
  We have in mind offshore nuclear utilities in Europe and Japan and international trading companies.

- **Organization**
  The same organization issues as were discussed in Option 2 apply here.

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6 ROIC is the Return of Invested Capital and can be interpreted as the operating cash flow available to debt and equity holders divided by the net plant investment. It must be higher than the Weighted Average Cost of Capital to ensure that the company’s shareholder value is not destroyed.

- **Satisfying NRC Financial Requirements**
  The increasing diversification of owners may actually be a negative if corporate parent guarantees become necessary.

- **Size of the Investment in Plant Construction**
  The addition of new parties spreads the cost and risk to even more manageable levels.

- **Financing Plant Construction**
  The presence of the reactor supplier in the ownership consortium will be a positive for investors particularly if it results in or adds assurances to a firm price contract. The participation of offshore investors is a positive if they are also able to bring financing to the project.

- **Return on Invested Capital Needed for this Ownership Group**
  This ownership group is diverse in many respects and that includes their desired ROIC. These particular investors would need a higher return for their investment to account for the fact that power plant ownership is not a core business, However, the degree of ownership of these nuclear industry investors is not likely to exceed 10% so that the aggregated ROIC would increase by only an estimated 0.5%.

5.7. THE ROADMAP STARTS HERE

One of main purposes of this Study is to prepare a roadmap for TIACT member companies on how they or anyone else would go about getting a new nuclear plant built in Texas.[7] This roadmap begins with the creation of a project development company (TGCN.) The initial purpose of TGCN, as discussed earlier, is to marshal the interest that does exist among various parties and to focus that interest on the steps needed to initiate the project.

These steps are:

(1) Determine the real cost to construct a new plant by

- Hiring an experienced engineering firm.
- Writing a bid specification for a new plant by updating and customizing the EPRI utilities requirement document.
- Reviewing and evaluating the bids; and then
- Selecting a plant design/prime contractor .

(2) Select a plant site

- Sign an agreement in principle with the site owner.
- Hire the leading environmental firm in Texas or the U.S.

7 The other is to prepare a prospectus, loosely defined, for discussion with potential investors.

(3) Secure financing for the plant.

- Make frequent presentations to potential investors about the TGCN business case.
- Determine the likely financing terms, including debt-to-equity requirements.
- Put in place the arrangements for a line of credit to finance construction, to be exercised upon receipt of the COL.
- Arrange for sufficient owner's capital to meet the needs of the financing terms (amount of equity) and the construction schedule (cash flow).

(4) Hire a leading public outreach firm to immediately begin the process of informing the public and building support.

(5) Start the COL process as described in the Task 4 report

- Hire the leading environmental firm in Texas or the U.S. to prepare the Environment Impact Statement.
- Establish a presence in Washington DC to closely follow the COL proceedings at the NRC.

5.8. CAPITALIZING TGCN FOR THE DEVELOPMENT STAGE

5.8.1. The Issue of Risk

Putting development capital at risk is common to any business venture. Sometimes this risk can be substantial as has been demonstrated by recent experience with combined cycle merchant power plants, many of which are now distressed assets. Drilling for oil and natural gas is a high-risk endeavor. In both these cases, the fear of failure has not been a deterrent but a cause for careful risk management. The risks associated with the project development phase of a new nuclear project are in reality no more or less than those in the two examples but we think there is one difference–the perception that such a risk is unusually high.

We think that there are few reasons for this. One is that a new nuclear plant has not been licensed and built in the U.S. in over a generation so there is much misunderstanding of the advances that have been made in both technology and regulatory affairs. It is interesting to see the scales fall from the eyes of individuals when provided with information on how the nuclear industry has progressed since the late 1970s. We ourselves have become more optimistic about the workability of the COL process, for example, as the result of the research done in Task 4.

This perception is also fueled by the conservative approach to risk taking by IOUs and especially the regulated IOUs. This conservatism and the risks associated with a new nuclear plant, including the development phase, are not especially good fits. This is not meant to disparage the management of IOUs, far from it. They are responding to the needs of their shareholders and by extension the analysts for a safe, steady investment.

On the other hand, the risk profile for large industrial firms in the petrochemical industry is much different and there are other potential investors that have similar appetites for risk.

Our point is that the development phase, which includes all activities and costs incurred up to the time when the COL is issued, does not represent an inordinate amount of risk and can be further reduced, we think, by use of the risk management strategies discussed throughout this report and collected together in the Task 8 report.

5.8.2. Estimates of Development Capital Needed

There are several costs that need to be funded during the development phase and some are dependent upon choices–the choice of a plant design for example or how much of the risk management strategy the consortium decides to fund. Table 5.2 provides a cost and schedule breakdown.

Table 5.2. Estimate of Development Capital Needed

Project Development	**Cost in $M**
Startup Costs	$0.25
Establish Capital Costs	$15
Public Outreach	$10
COL Preparation	$5
COL Review	$10
Contingency at 20%	$8
TOTAL	App. $50M

5.9. SUMMARY AND RECOMMENDATIONS

There is widespread support for building more nuclear power plants in Texas but a basic question is "Who will own it?" The answer to that question must take into account the two characteristics of this endeavor that are unique in the industry. One is the involvement of large industrial electricity users and the other is that the plant would be located in ERCOT where both the wholesale and retail markets have been deregulated for several years. These two characteristics shape the nature of the ownership arrangements.

It is the recommendation of this report that such arrangements be based upon a version of the ownership model used with great success by the Finnish utility TVO for its new nuclear plant (construction to start in 2005.) It further recommends the creation next year of a development corporation, aptly named "TGCN, Inc.", to begin the work of marshalling the widespread interest in a new plant and transforming it into an ownership consortium.

Table 5.3. Summary Comparison of Ownership Options

	Option 1	Option 2	Option 3
Satisfying NRC 's financial requirement	0	+	+
Size of the Investment in Plant Construction, per investor	0	+	++
Financing Plant Construction			
• Debt to Equity	0	0	0
• Interest rates	0	+	++
• Weighted Average Cost of Capital	0	+	++
Return on Invested Capital	0	-	-
Development Capital	0	0	0
Degree of difficulty pulling it together	0	-	--
Overall Assessment	#3	#2	**#1**

- - two negative counts
- a single negative count denoting the option has a weakness in this area
0 no counts for or against
+ one positive count denoting that the option has a strength in this area
++ two positive counts

The total score for an option is found by summing all of the counts for and against the option.

TASK 6

ESTABLISH PRO FORMA FINANCIALS

TASK 6. ESTABLISH PRO FORMA FINANCIALS

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TASK 6. ESTABLISH PRO FORMA FINANCIALS

6.1. INTRODUCTION[1]

Task 6 evaluates the economic attractiveness of the project and whether the proposed nuclear plant will be capable of attracting development and construction capital. Market, financial and performance risks are assessed and measured. The objective of Task 6 is to provide TIACT with a means for making an informed decision about whether or not the construction of a nuclear plant within ERCOT is economic.

Generating electricity with nuclear energy has many recognized advantages, including its contributions to maintaining a healthy diversity of supply and to reducing carbon levels for which there is an increasing desire to take stronger action. In addition, studies have shown that nuclear electricity is a competitive option, especially if your view is that higher natural gas prices are here to stay.

For example, The results of the study entitled "*Business Case for New Nuclear Power Plants: Bringing Public and Private Resources Together for Nuclear Energy*" by Scully Capital Services[2] (July 2002) indicated that the cost of electricity from an advanced nuclear plant (the AP1000) would be about $40/MWh, a cost that would be immediately competitive with coal and combined cycle. This is perhaps the most optimistic assessment we have seen although vendor studies are equally rosy.

At the other end of the spectrum, forecasts made by the Energy Information Agency in *Annual Energy Outlook 2005*[3] show no new nuclear power plants being built between now and 2025.

The most recent study of nuclear plant economics, "*The Economic Future of Nuclear Power*," by the University of Chicago takes up ground in the middle of the spectrum. It is upbeat about the long-term prospects but concludes that nuclear electricity is not now competitive with either combined cycle or coal. This near term condition can be overcome with a combination of limited and short-term federal financial incentives to help surmount the unique financial hurdles associated with building the first few new nuclear plant designs (first time costs, e.g.). Their conclusion is "After engineering costs are paid and construction of the first few nuclear plants has been completed, there is a good prospect that lower nuclear LCOEs[4] can be achieved and that these lower costs would allow nuclear energy to be competitive in the marketplace." This is an upbeat but not a definitive assessment.

1 Within Task 6, EPC Cost (not Total Overnight Capital Cost) is the predominant cost category used. This differs from the remainder of the report where total overnight capital cost is emphasized.

2 Scully Capital Services Inc., an investment banking and financial services located in Washington D.C.

3 http//www.eia.doe.gov/oiaf/aeo/pdf/appa.pdf .

4 Levelized Cost of Electricity.

The authors of *The Future of Nuclear Power* (MIT, 2003) reach a similar but not identical conclusion. New nuclear plants are not now competitive but can be made so by decreasing capital costs from $2,000/kWe to $1,500/kWe, reducing O&M costs further, shortening the schedule and so on, presumably as pre-requisites for (rather than as the result of) building the first few units.

Is nuclear electricity competitive now, will it be in the future, or not at all? And why is that no one has ordered a new plant despite all of the economic improvements that have been made in the advanced designs?

That this question is being asked is, we think, the most telling aspect of all. For what gives rise to this question is the uncertainty that surrounds the cost of nuclear electricity and it is sufficient to give pause to potential investors. The combination of this hesitancy on the part of investors and the considerable risk involved with commissioning a new plant has all but frozen potential owners in place.[5]

However, this uncertainty and risk can be overcome by deconstructing the risks so that they can be addressed in a stepwise manner that makes financial sense. When several stepwise actions have reduced the overall risk to a level that appeals to a large number of investors, then investment of the size represented by a nuclear plant can be readily obtained. Our business model is founded upon this approach.

With this approach in mind, we divide project development into three tollgate phases

1	Firm up EPC costs through actual RFQs	EPC tollgate (2005)
2	Apply for a COL	COL tollgate (2007)
3	Construct plant	Construction tollgate (2010)

There is an investment to be made at the beginning of each phase; at the end of which the investors have the option to proceed to the next phase should uncertainties be resolved satisfactorily.

We believe this approach has economic justification and is perhaps the only way to overcome the barriers to the next round of new plant construction. This Task 6 will go into some detail to justify the economics and to show why this approach is superior to the simple and traditional capital budgeting approach.

The purpose of this Task 6 report, then, is to provide the quantitative basis for a nuclear plant. This study's quantitative analysis is based upon real options theory for which there is a significant body of work upon which to draw.[6]

5 There are a few exceptions but these are proposing plants that would be subject to state regulation and therefore have assured revenues.

6 Please refer to Appendix 6B for a full description of this model, including the use of probability distributions and Monte Carlo methods to model how uncertainties and risk affect the expected financial returns from the project.

There are two other aspects to the economic modeling that should be highlighted. The first is that an economic valuation method is not the one commonly used in nuclear competitiveness studies. Whereas all the studies done to date calculate the levelized cost of electricity as the figure of merit, we rely on cash flow and project valuation as key metrics. Increasingly CFOs have been adopting this approach to evaluate new business opportunities. The former method was designed to meet the needs of regulated utilities whereas the latter grew out of the need to measure the impact of the project on corporate value. We believe this latter method, which is considerably more sophisticated, is not only preferred but is necessary for a potential project in the deregulated ERCOT market.

The other aspect is a new and unique treatment of nuclear plant capital costs. In Task 3, we catalogued and analyzed the capital cost estimates provided to us directly by the plant suppliers.

If there is one thing that we can all agree upon, it is that there is widespread skepticism for the estimates of nuclear plant capital costs. One can pick a cost number to use in the analyses, say $1400/kW, but the results then come into question because the number is hard to defend. Alternatively, one can bracket the results by using a low cost figure and high one but the results won't be terribly meaningful because we don't know which cost number, the low or the high one, is more likely to occur.

So, in hopes of getting more meaningful results, we treat each plant's total overnight capital cost estimate as a lognormal probability distribution. The mean of this distribution is the cost of the first unit as provided by the plant supplier. The standard deviation is equal to the contingency of the cost estimate, as determined by a method devised by Dr. Rothwell. (All of this is fully explained in Task 3.) Then, and this is worth noting, all of these individual probability distributions were averaged together into a single "what the market has to offer" distribution. In other words, if we were to go out for bids today, we would expect the market (bidders) to respond by submitting a bid equal to the mean of this distribution ($1535 per kW as it turns out.).

Finally, it is important to note the context of the analyses to be discussed next. It is that of a project developer who plans to build a new nuclear plant in a de-regulated market; not an analyst making another economic assessment of nuclear power, or an electric utility keeping an option alive without the specific intent of ever building a plant.

6.2. PRINCIPAL FINDINGS

Since no nuclear plants have been ordered in the U.S. for over 30 years, that have not been subsequently cancelled, there is considerable uncertainty over some of the key costs which greatly affect the decision to invest in the project. When uncertainty is present and investments are irreversible, investors do not behave in the manner described by the traditional capital budgeting approach (i.e., NPV as the decision rule). They will attempt to resolve uncertainties before committing to full investment; and they will exert considerable influence over the timing of the investment. Without taking this into consideration, results from financial analyses can lead to faulty conclusions. For instance the net present value of the TGCN plant is about -$100 million while the strategic value of the plant is actually $100 million positive.

The key uncertainties in the case of the TGCN plant are:

1. When it comes time to sign a contract, will the EPC portion of the plant actually be as low as suppliers estimate or, as many suspect, will it be higher? Will it be significantly higher?
2. What will be the terms of the construction loan, including interest given investor's still lingering perception of the last round of nuclear plant ordering and construction?
3. What will be the cost of the new COL process, and will the NRC agree to and meet a timely review schedule?
4. Is it still likely that the construction schedule can be delayed or even halted through legal challenges brought by groups opposing nuclear power, or even by consumers who don't wish to have a nuclear plant nearby?
5. Will electric market pricing reflect the environmental need to limit carbon and other fossil based emissions in the near future?

These need resolution.

Less likely to need resolution is the expected performance of the nuclear plant, since performance gains have been considerable over the last decade. U.S. nuclear plants are now routinely running at 90-95% capacity factors. Unfortunately, there are recent examples of extended shutdowns, although these are just as likely to be brought on by management failings as opposed to technology issues.

These uncertainties, and how investors will respond to them, require new methods of financial analysis; one that sees a nuclear plant as an option against higher electric prices resulting from fossil fuel based generation's limitations. A more appropriate model is one that recognizes that investors do have the ability to change plans as uncertainties are resolved, either satisfactorily or unsatisfactorily. The new economic model uncovers the value of such flexibility and sees the nuclear investment process as a series of tollgates where *go* and *no go* decisions are made. Each tollgate is passed only when uncertainties are resolved favorably and the new NPV of the plant is updated to reflect the new information. Further, this analysis reveals how much investment is justified at each tollgate.

When this approach is used on the TGCN plant there are three key findings:

1. The strategic value of the TGCN plant is about $100 million - considerably higher than the negative $100 million resulting from a traditional capital budgeting approach with its flawed view of investor behavior;

2. The high level of uncertainty suggests that a tollgate process of at least three stages be used. The first phase (costing approximately $10-$25 million) resolves the EPC cost uncertainty, and determines the cost and schedule of acquiring a COL. Then the second tollgate decision will be made. If the tollgate decision is to proceed then another $30-$60 million (and possibly higher) will be spent on obtaining the COL, performing early site work and obtaining construction financing. Finally, in the third phase, the decision to begin construction must be made or the plant abandoned. Unless uncertainties have been

sufficiently resolved then a “no go” decision to construct the plant will be the result.

3. The analysis reveals that the two key pre-operational uncertainties facing the plant are the EPC costs and the potential for significant schedule delay. The latter risk is what leads financial institutions with whom we have spoken, to say that the terms of the construction loan will be unfavorable (high interests rates and more equity required.)

4. Once construction is complete and the plant goes into operation risk levels are reduced. The risks faced during operation are more manageable under an active risk management strategy. Because it is expected that the TGCN plant will be a top quartile performance plant, then the chief uncertainty during operation is market price risk. (See Task 8 for a better description of the active risk management program.)

The conclusion reached by this economic assessment is that the investment in the TGCN plant should proceed immediately using the tollgate procedure. The funds expended during the first 5 years are relatively modest and are devoted to reducing the key uncertainties that are rendering the plant uneconomic under traditional methods of capital budgeting.

6.3. A SUMMARY OF THE RESULTS OF THE NUCLEAR PLANT ECONOMIC ANALYSIS

There are three major results that are derived from the financial assessment pursued in this Task 6:

Result #1 The strategic value of the TGCN plant is $100 million.

Result #2 Because most uncertainty can be resolved prior to the start of construction it is necessary to depart from traditional nuclear plant contracting practices and move forward using a “tollgate” process. Each tollgate requires an expenditure to resolve the uncertainty and move to the next tollgate.

(a) Tollgate #1 The EPC *tollgate* requires an estimated $10-$25 million to determine what EPC costs are under an actual plant RFQ process

(b) Toll Gate #2 The COL *tollgate* (estimated $30-$60 million) is exercised when EPC costs have been satisfactorily resolved, and

(c) Toll Gate #3 The construction *tollgate* ($2.5 billion) is exercised when all uncertainties are resolved sufficiently to provide the plant with a positive NPV using traditional capital budgeting. Most of the uncertainty in the TGCN plant lies in pre-construction phases.

Result #3 The analysis reveals that the TGCN plant project should seek funding for the first tollgate immediately.

Section 6.4 will discuss these results in more detail.

6.4. DISCUSSION OF RESULTS

If we use Monte Carlo simulation to project the expected net present value of the TGCN plant, Figure 6.1 results. As shown, the expected (mean) value is about -$110 million. However, what is more important is that there is a 70% probability (shown in red) that the TGCN plant will realize a negative NPV. Overall, as shown, there is a 90% probability that the actual realized NPV of the plant will be between $104 million and -$400 million. Most of the negative probability results from uncertainty about EPC costs; the average EPC cost is $1535/kWe as mentioned; However, the EPC costs range from $1400/kWe to $1800/kWe in the lognormal probability distribution used in the Monte Carlo simulation.

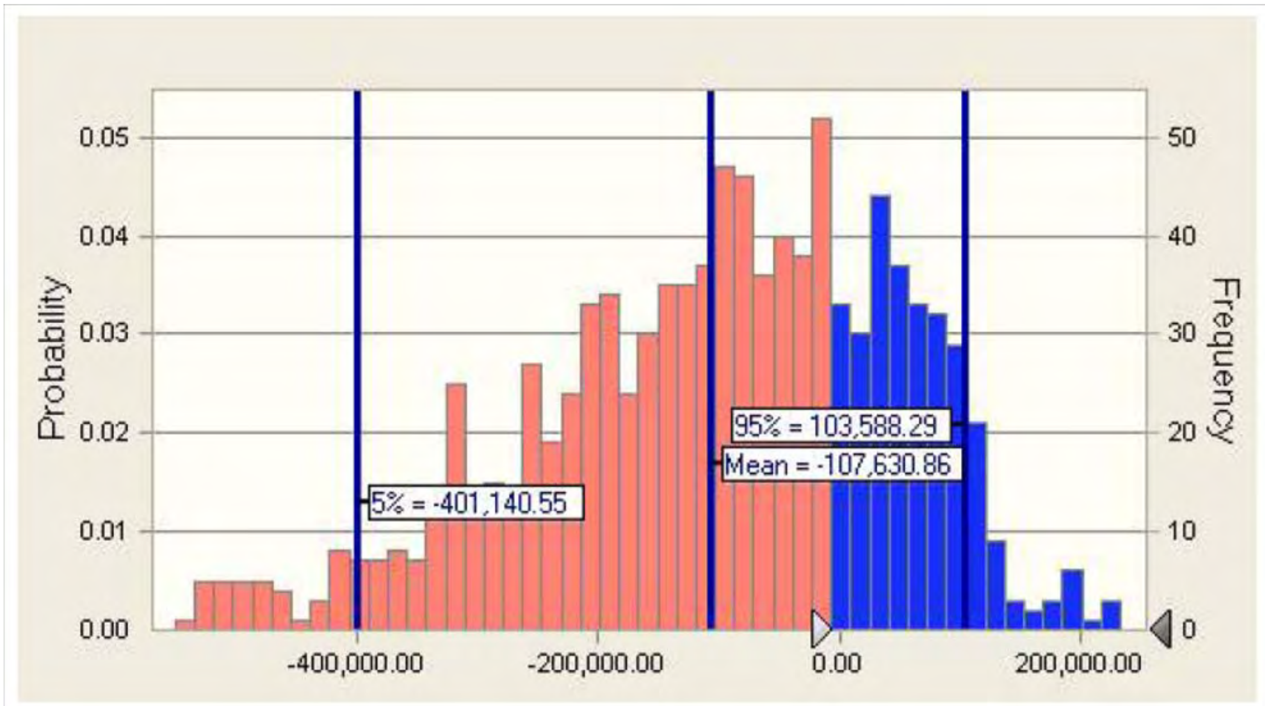

Figure 6.1. Monte Carlo Simulation of Net Present Value

The sensitivity of expected NPV to EPC costs is shown in Figure 6.2. All else being equal, EPC costs below about $1450/kWe will result in a negative NPV. Unless there is a compensating adjustment elsewhere (market pricing, plant performance, loan guarantees, etc.) this then represents a barrier.

Just as important as EPC cost is the cost of construction financing. We've assumed a 50:50 debt/equity ratio and a 7.1% real rate of interest on debt; and some finance professionals indicate that this still may be too low, given nuclear's past performance.

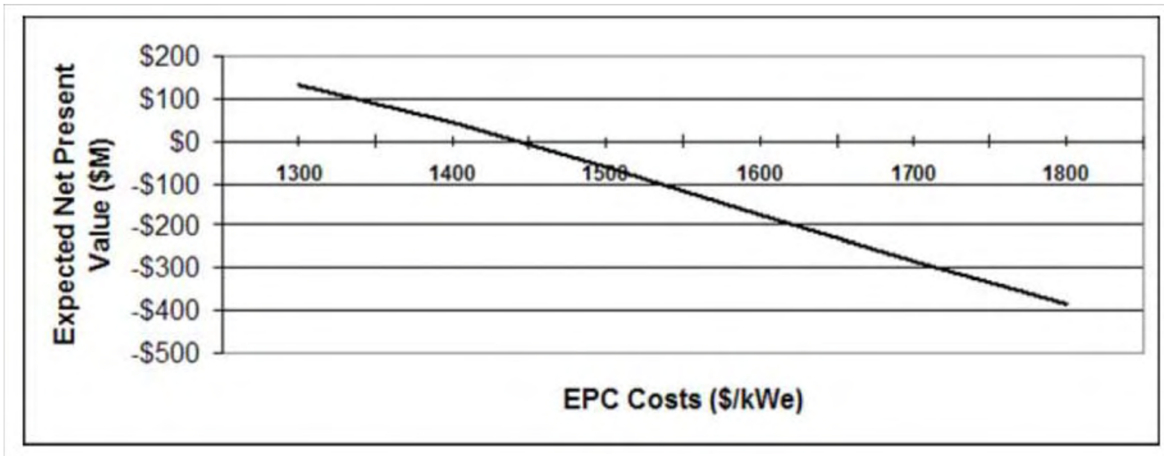

Figure 6.2. NPV with EPC Costs at $1300/kWe

The risk here is that the potential investors are concerned that the plant cannot be constructed at the budgeted costs, that the plant suffers delays when substantial funds have already been expended or that the plant is never completed owing to legal challenges from groups opposing the use of nuclear power. Any of these can prove disastrous to the returns that investors can expect from the plant given that there is no rate base to which an appeal can be made.

One of the ideas brought forward during the latest round of congressional energy policy discussions was that of a government loan guarantee for a limited number of nuclear plants. This form of a construction loan backstop was mentioned frequently during discussions with finance professionals; and so it was decided to look at what impact this might have.

The results are shown in Figure 6.3 where we have raised the debt/equity ratio to 75/25 and lowered the real cost of debt capital to 2% (the debt risk premium is removed). Barrier EPC costs can not be raised to about $1550/kWe which increases the probability that a nuclear supplier's technology will make the "cut".

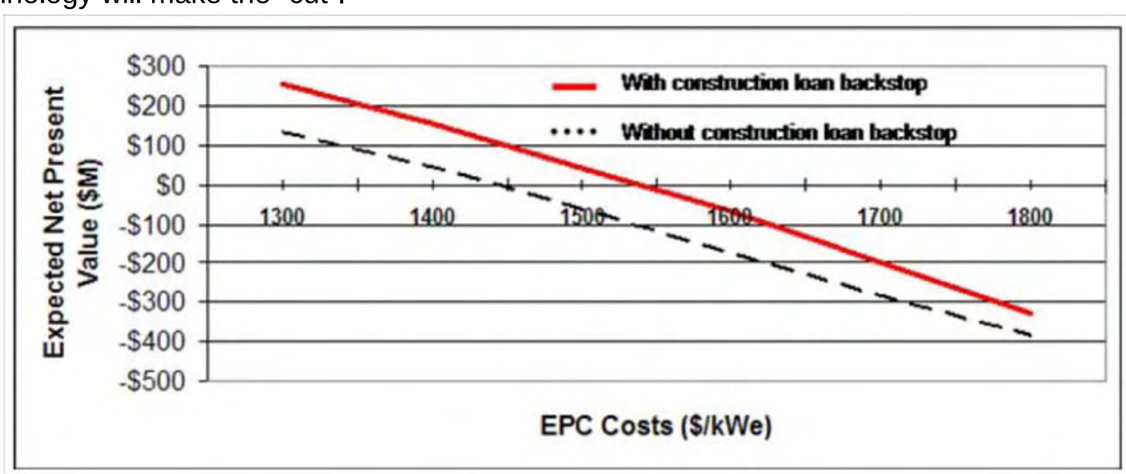

Figure 6.3. Impact of a Construction Loan Backstop

6.5. RESOLVING UNCERTAINTIES

There are assumptions built into the NPV analysis (largely unconsidered by nearly all financial analysts) that render it highly questionable for making financial decisions when uncertainty can be resolved over time and management has flexibility to react to new information.[7] This is the basis behind our tollgate approach.

The ***value*** of the TGCN plant will emerge as the market price uncertainty is resolved (since the plant has been modeled as a top quartile performer, plant performance uncertainty is not a significant contributor to plant value in this model). Up to that point nearly all uncertainty lies in the cost of the plant and the factors that contribute to it. This means that both the plant value and the plant cost will be uncertain up until the decision to execute the construction tollgate, although there is considerably more uncertainty surrounding the plant cost.

Table 6.1 shows the strategy for resolving the uncertainties that are affecting the plant's NPV.

Table 6.1. The Uncertainty Resolution Process

Uncertainty	Period of Uncertainty Resolution	Vehicle for Resolving or Managing Uncertainty
EPC Costs	Pre-construction	Tollgate Process
Construction Delays	Pre-construction	Tollgate Process
Market Pricing	Post-construction & Pre-construction	Risk Management Strategy (Task 8)
Production Costs/Capacity Factor	Post-construction	Risk Management Strategy (Task 8)
COL Costs	Pre-construction	Tollgate Process

So, there are three uncertainties that are resolved during the pre-construction phase of the plant: EPC costs, COL costs and the potential for construction delays. Unless these are resolved satisfactorily, the project will not expend the increasingly higher level of funds as the construction tollgate approaches.

This is shown schematically in Table 6.2.

7 Using arbitrarily higher discount rates than would be used for a much less uncertain project is acceptable in modern financial theory. However, the problem then shifts to what discount rates should be employed. Since no new nuclear plants have been ordered in the U.S. for over 30 years, which were not subsequently cancelled; and, in any case, none have ever been built in deregulated markets without electric utility ownership, there is no directly applicable market priced risk information to draw on.

Table 6.2. Texas Gulf Coast Nuclear Plant Tollgate Plan

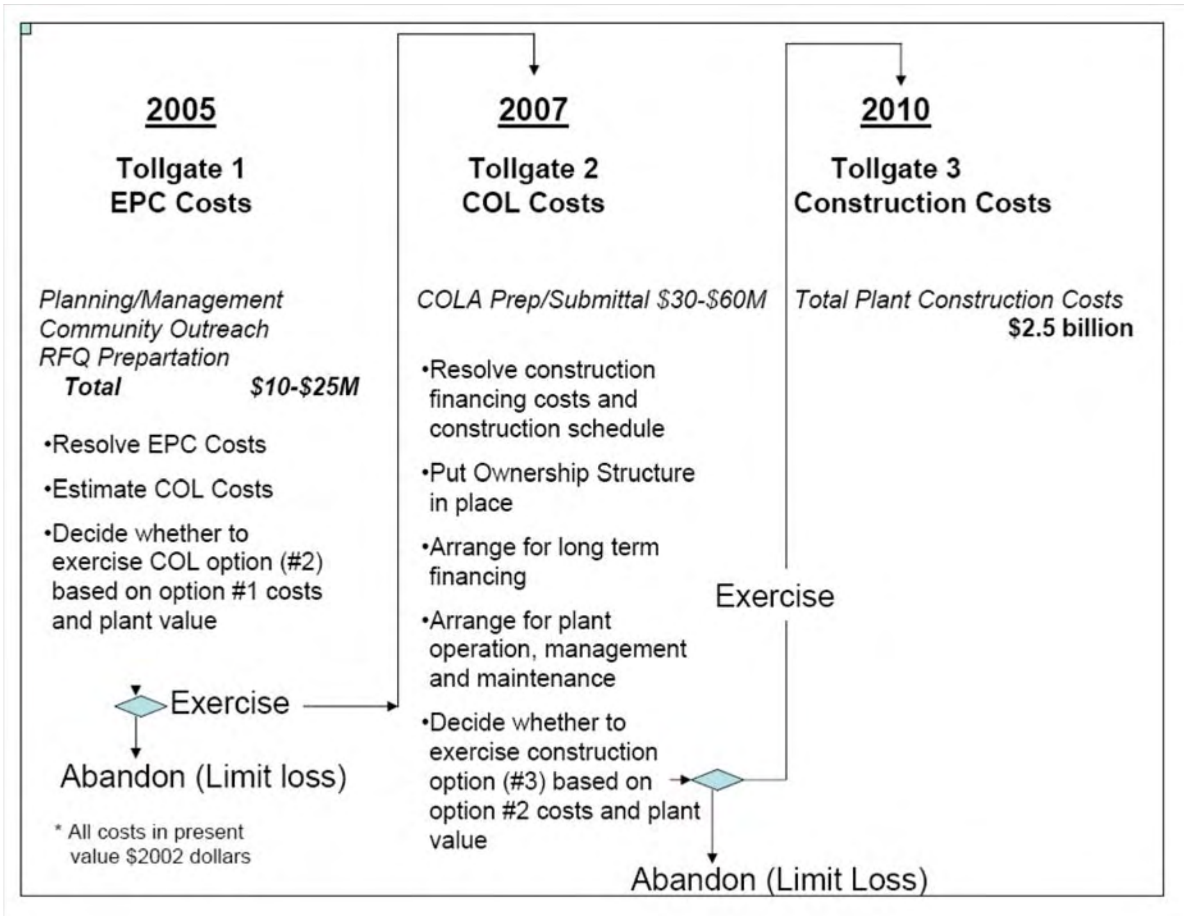

Table 6.2 shows the tollgate process for undertaking construction of the plant. There are three periods where a decision is made as to whether to bridge the tollgate (see the blue parallelograms). These decisions are based on whether or not the nuclear plant has enough value to permit expending the costs needed to bridge the tollgate. The nuclear plant value will evolve over time, particularly as market pricing is resolved. As uncertainties are resolved, and if they are resolved in a manner which maintains a positive expected NPV, then the construction tollgate will be exercised and construction will begin. Ultimately, if the uncertainties are not resolved, or if they are resolved unsatisfactorily, then the construction tollgate will not be exercised and the project will be ended or put on indefinite hold.

6.6. THE JUSTIFICATION FOR THE TOLLGATE PROCESS

As has been made abundantly clear, uncertainties must be resolved before the decision to construct the plant is made. Further, if the plant is to remain on schedule to meet DOE's NP2010 initiative during the lengthy pre-construction period of about 5 years, then these uncertainties must be resolved actively; the option to resolve them through simply waiting has an opportunity cost because it will postpone plant startup (i.e., it will delay cash flow receipt).

Using real options theory it is possible to decide if there is value in resolving uncertainty, even though the plant currently exhibits a negative NPV. Real options theory recognizes that uncertainty is resolved over time with the accumulation of information and that the plant owners have the flexibility to act upon this information by abandoning any further investment should the uncertainty be resolved unsatisfactorily. They also have the capacity to continue on the planned schedule if the accumulated information reveals the plant NPV is likely to be positive. This flexibility has most value when the plant's NPV is negative or close to zero. If the plant's NPV were significantly negative (say, negative $1 billion) then there would be little chance that the flexibility would have any value. That is not the case here, where the negative NPV is approximately 12% of the present value of investment (approximately $1.4 billion).

This flexibility has value that is not recognized in the traditional NPV analysis. If an investment were made immediately (instead of waiting) then the option value would be lost. This value represents a cost - the opportunity cost of waiting. So, whereas the decision rule in the case of the NPV analysis was to invest only if the expected present value of the plant exceeds the present value of the investment, the decision rule where flexibility is present is only to invest if the expected plant value exceeds not only the present value of the investment, but also the present value of the opportunity cost. If the expected present value of the plant does not exceed both, then it is best to wait and resolve uncertainties, spending up to the strategic project value to do so. This is shown in Table 6.3.

The first column shows the plant's expected present value (the present value of the plant's free cash flow during operation as calculated by a traditional NPV assessment). This is a random variable since the present value of the plant cannot be determined until most of the uncertainties are resolved. The second column is expected present value of the investment in the plant. Column 3 is the expected NPV of the plant were the investment to be made immediately. Column 4 shows the strategic value of the investment with flexibility (the option value). This is calculated using a real options framework, and should be compared with the expected net present value in column 3. The difference between the two represents the value of flexibility (the "option premium"). Finally the last column shows the action to be taken given the results in each row.

The point of the table is to show that even when the plant NPV is negative, there is justification to spend money to acquire more information rather than to make the decision not to invest. The expected present value of the plant for a traditional NPV analysis is estimated to be about $1250 million, so the table shows there is substantial value to acquiring more information instead of deciding to not make the investment.

Table 6.3. The Decision to Invest Using Real Options and Why it Justifies Use of the Tollgate Investment Process

Expected Plant Present Value ($M)[8]	**Expected Present Value of Plant Investment ($M)**	**Expected NPV of Immediate Investment ($M)**	**NPV with Management Flexibility ($M)[9]**	**Value of Management Flexibility ($M)[10]**	**Decision[11]**
E(PV)	E(PVinv)	E(NPV)	Strategic Project Value (Option Value)	Option Premium	
(1)	(2)	(3)=(1)-(2)	(4)	(5)=(4)-(3)	(6)
$1,200	$1,396	($196)	$73	$269	Wait
$1,300	$1,396	($96)	$130	$226	Wait
$1,400	$1,396	$4	$194	$190	Wait
$1,500	$1,396	$104	$268	$164	Wait
$1,600	$1,396	$204	$354	$150	Wait

Why does this result emerge?

Uncertainty creates opportunity, and the more uncertainty there is the greater the opportunity. The opportunity arises because high uncertainty means there is a higher probability that as the uncertainties are resolved that the plant will emerge with a positive NPV. Of course there is an equally good probability that the plant NPV will be negative as well; but an asymmetry exists that is the source of the option value. If the plant NPV emerges as positive when the construction tollgate decision must be made, then the tollgate will be exercised and plant construction will begin. On the other hand, if the NPV emerges as negative, then the construction tollgate will not be exercised and the losses will be limited to the monies spent up to that time (which are far less than

8 The expected plant present value represents the operating value of the plant calculated using a traditional NPV analysis.

9 The NPV with management flexibility is calculated using real options theory. For a discussion of real options theory see Appendix 6C.

10 The value of management flexibility is the difference between the traditional expected NPV calculation in column 3 and the NPV with management flexibility in column 4. It is the opportunity cost of not waiting to invest

11 The decision rule is as follow: (a) E(PV) > PVinv + Option value then **invest** immediately; (b) E(PV) < PVinv + Option Value then **wait to invest**. This is a modification of the traditional NPV decision rule which advises to invest only when E(PV) > PVinv and not to invest otherwise. According to the revised decision rule the value of waiting to invest is “killed” when an investment is made immediately instead of waiting for uncertainty to be resolved. Thus, this represents a cost to be taken into account.

the construction costs).

Notice in Table 6.3 that as the plant NPV rises, option value becomes less important in making the decision to exercise the tollgates. Finally when the option value equals the expected NPV (i.e. when the option premium goes to zero), then there is no longer any justification to waiting—invest immediately. There is no value in waiting any longer since there is sufficient value in the plant to "absorb" risk.

The tollgate process that is recommended in this Study emerges from a real options analysis (see Appendix 6C). Table 6.2 shows how the real options analysis will be put into practice. The decision as to whether or not to exercise a tollgate will depend on the amount of uncertainty that has been resolved. As it turns out over 90% of the uncertainty in the TGCN plant can be resolved prior to having to make the decision to construct the plant. The remaining uncertainties will be managed with a risk containment strategy discussed in Task 8.

This is all summarized in Table 6.4 below.

Table 6.4. Justifying the Spending at Tollgate 1 (EPC Costs)

TGCN plant	**Value**	**Implication**
Net Present Value (NPV)	-$100 million	TGCN plant is not economic under a traditional NPV assessment
Strategic Plant Value (calculated using a real options framework)	$100 million	Since the strategic plant value exceeds the net present value then there is value in the options to wait and resolve uncertainties rather than to not undertake the investment at all (as the traditional decision rule would advise).
Recommended Strategy		The TGCN plant project should begin immediately since the expected spending to resolve EPC costs at tollgate 1 is only $10-$25 million, and the project strategic value justifies spending up to about $100 million (see Table 6.3 for the E(PV) of $1200 The allowable spending is the strategic project value).

Since the strategic value of the TGCN plant is $100 million and the actual estimated spending to resolve the EPC costs is between $10-$25 million then there is justification for moving the project forward while minimizing the capital outlays.

6.7. HOW THE WORK WAS PERFORMED

There are six steps in Task 6 which lead to a recommendation of the strategy to pursue.

Figure 6.4 illustrates the steps involved.

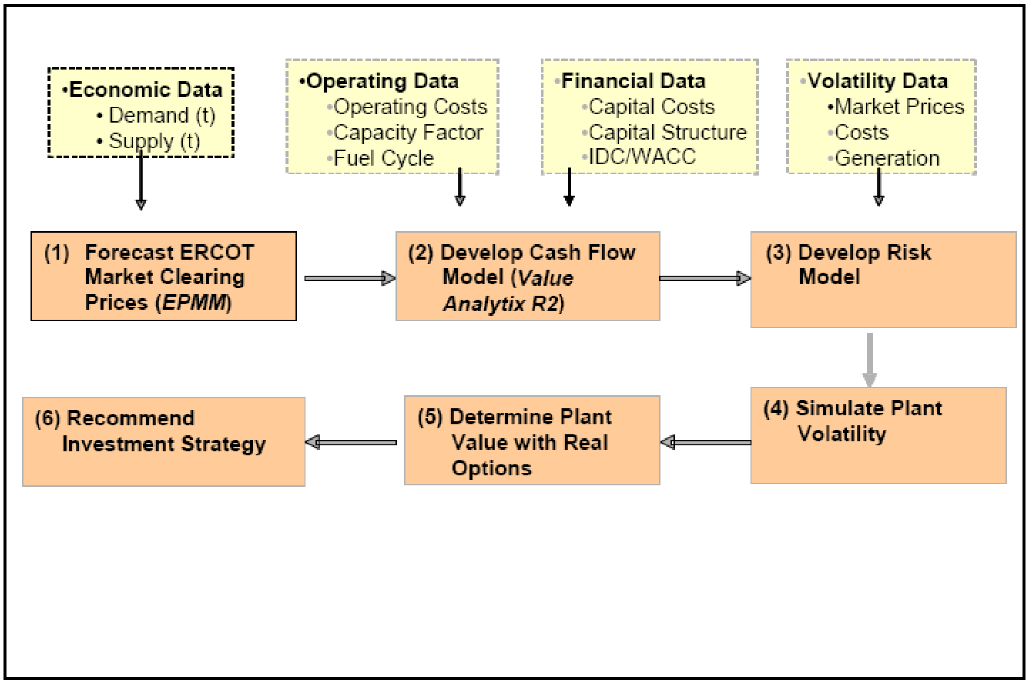

Figure 6.4 The Work Steps in Task 6

6.7.1. Forecast Market Clearing Prices in ERCOT

The first step in the process is to obtain market clearing prices in ERCOT as this forms the basis for revenues and subsequent value of the nuclear plant. This is done by using the Electric Power Market Model (EPMM).[12] EPMM is a structural power market model which dynamically forecasts prices by equating electricity demand and supply. Markets are simulated and cleared every 15 minutes and new capacity is built based on long run marginal costs.

EPMM does not have a fuel module and so uses commodity fuel prices as input to the model. In order to base the fuel forecasts on recognizable ground, fuel forecasts from EIA's *Annual Energy Outlook* are used. This is especially relevant for natural gas since ERCOT is so heavily dependent on natural gas. However, gas prices are volatile and can greatly affect the forecasted electric prices. Nevertheless, we did not stray far from the natural gas price forecasts used in the AEO, preferring to use scenarios instead.

12 The Electric Power Market Model is a product of the Economic and Management Consulting Group LLC in Stony Brook, New York (www.emc-group.com).

Three scenarios were chosen; two were based on variations in natural gas prices and one was characterized by having a stringent emissions cap. This provided a range of forecast prices which were used to model the cash flow in the second step.

6.7.2. Develop Cash Flow Forecasts and Assess Financial Performance of the Nuclear Plant

Because the proposed nuclear plant will be privately funded and operated by a non-utility corporation, a more conventional financial assessment was performed and based on creating value for stakeholders in the project. In order to avoid accounting errors, we used Value Analytix' R2 financial and accounting software.[13] This required the nuclear plant to be modeled in detail so as to accurately assess the free cash flow that is generated by plant operations. This free cash flow is then used to calculate whether or not the plant is creating value for its owners and lenders.

6.7.3. Develop Risk Model

In order to assess the risks, we elected to use Crystal Ball™ software.[14] CB is a Monte Carlo simulation program that models uncertainties with a large array of probability distributions. We elected to model risks explicitly so that a measure of dispersion around a central tendency could be measured. This avoids the use of point forecasting wherein a single forecasted measure is used to make decisions. CB is used for two purposes: to develop the volatility and the probability distributions of forecasted variables.

Since CB is an Excel add-in it is necessary to build a shadow model in Excel. The shadow model is an Excel version of Value Analytix and is constantly benchmarked against the results of R2 to insure that no accounting errors have occurred as the analysis proceeds. So, the risk model is comprised of R2, CB and the Excel shadow model.

6.7.4. Simulate Plant Volatility

In anticipation of using a real options model to determine if there is any value in flexibility, or for waiting for uncertain input to be resolved, volatilities are generated in Crystal Ball for all key value drivers. There are six such variables:(1) EPC costs; (2) construction schedule and costs; (3) COLA costs; (4) electric market clearing prices; (5) capacity factor, and; (6) production costs. Crystal Ball simulation is used to value the standard deviations of these variables-the key input into the real options model.

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13 Value Analytix is a private financial consulting firm which markets its proprietary software to its clients. Value Analytix is in London England. (www.valueanalytix.com)

14 Crystal Ball is the product of Decisioneering in Denver, Colorado (www.crystalball.com)

6.7.5. Determine Plant Value with Real Options Model

The *Real Options Analysis Toolkit*™ was used to perform the real options analysis.[15] The purpose of real options is to determine whether uncertainty is giving rise to the need to acquire more information prior to making a decision to invest. Further, there may be flexibility inherent in the project which allows management to modify, enhance, or abandon the investment if information is satisfactorily resolved over the passage of time. Real options are important if an investment is either slightly negative or positive. It uncovers the value that resides in flexibility and the acquisition of additional information and can limit the losses that might be incurred in an investment that ultimately turns out poorly.

6.7.6. Recommend an Investment Strategy

Once the value of the plant is established from the use of *R2* and the real options analysis, then an informed decision can be made about the likely result of making an investment or waiting.

15 *The Real Options Analysis Toolkit* is a product of Decisioneering, Inc. of Denver, Colorado (www.decisioneering.com)

TASK 7

DEVELOP PROJECT FINANCING STRATEGY

TASK 7. DEVELOP PROJECT FINANCING STRATEGY

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TASK 7. DEVELOP PROJECT FINANCING STRATEGY

7.1. INTRODUCTION

Value Analytix, a London-based consulting firm advising clients on financial and management strategies, and which makes financial software for performing corporate and project valuations and risk assessments, was retained for Task 7. Value Analytix has substantial knowledge of capital markets, and is frequently retained by companies to advise them on the optimal approach for raising funds. Their accounting and valuation software is the most advanced in the world.

The company was requested to review the strategies we've outlined in the previous Tasks in this Study and to advise EnergyPath as to whether, in their view, these strategies are aligned with how capital markets work. Their report is included in its entirety as the main body of this Task report.

7.2. PRINCIPAL FINDINGS

Value Analytix (VA) principal conclusions are as follows:

1. It is unlikely that the TGCN plant can be privately financed without the assistance of the U.S. government in the form of debt guarantees during the construction of the plant because the plant has a negative $100 million NPV without such assistance. This is because investors are likely to be more concerned about legal, regulatory and environmental issues than they are about waste, security or radiation issues.

2. VA advanced the notion of raising capital through three tranches which EnergyPath refined to the progressive raising of capital through the tollgate approach. Although VA's financing schedule and amounts differ somewhat from the tollgate schedule, VA expects that the cost of capital in the initial tranche and the construction tranche will be higher than the costs used in the core study but the cost of capital will be equal to or lower than that used in the period from 2015 onwards as this reflects the declining risk and associated return with each subsequent phase. . The tranches are in the amounts of $100 million for technology selection and COL costs; $2.6 billion for construction, initial fuel load and working capital; and a final $400 million tranche to settle the final payments to the construction firm and reactor supplier and to fund the decommissioning requirements. The first tranche is critical and likely to comprise investors who see nuclear power as making a contribution to natural gas price and supply issues in Texas. These investors will still demand a reasonable rate of return on their investment given the inherent risks to their shareholders but without the incentive of supplanting natural gas as an electricity feedstock they would be unprepared to make any investment at all. Later tranches will be dominated by more traditional investors seeking a return on their investment appropriate to the level of risk they are taking.

3. The capital cost and structure estimates used in the Study, especially in the early stages, are probably optimistic. Capital costs are too low to accurately reflect the risks that potential investors will perceive. Equity costs in excess of 20% nominal can be expected in the first tranche. Later tranches will have lower capital costs; but the capital costs will still be higher than those applied to the core analysis in the Study.

4. When government debt guarantees are taken into account, then the plant may achieve a positive NPV on the current price and construction cost assumptions, but only if the capital structure is 75/25 debt to equity. Achieving the maximum level of lower cost debt in the capital structure is necessary to attract equity capital at a price that can deliver an economically viable power nuclear power plant. .

5. Once the plant is in commercial operation, a case can be made that the EnergyPath WACC of about 5%, in real terms, may be achievable as risks are substantially reduced once the plant is generating revenue.

6. VA recommends that an alternative financial assessment known as APV (adjusted present value) is more appropriate than a standard NPV analysis because it can model the project in multiple stages with differing costs of capital. Using the capital costs appropriate for each tranche (but not the very high cost of equity that may be encountered-20% or higher), this analysis reveals a slightly positive net present value of about $50 million which increases to about $115 million if government debt guarantees are provided.

In conclusion, then, Value Analytix believes that the project cannot be financed in private markets without a government loan guarantee. Further, they caution that capital cost estimates used by EnergyPath may be too low to accurately reflect investors' perceived risk, especially in the earlier phases of the project. When government loan guarantees are assumed then there is a possibility that the plant can be privately financed.

7.3. ENERGYPATH RESPONSE TO VALUE ANALYTIX FINDINGS

1. One of Value Analytix' key approaches is adopted for the purposes of the Study. VA's rationale for the schedule and amount of each tranche is related to the value of the asset created. For instance, VA sees the COL as having value whether or not the plant goes forward on schedule. In other words, investors have something to show for their efforts as long as a COL is obtained. We also believe that a signed contract with a nuclear plant supplier has value as well . If the contract is assignable for instance, it may possess market value as it specifies terms, conditions and prices to which the supplier has committed. We agree with VA that a COL can have substantial value since the NRC has a limited resource base. And, finally, a nuclear plant starts accruing value upon initiation of construction.

2. We are advised that the capital cost estimates used for the Study may be far too low. While we respect this conclusion and agree that capital costs may indeed be higher than was assumed in the Study, we will pursue the tollgate with full knowledge that we may not be able to pass the construction tollgate because of these high capital costs. We also recognize that investors in the first two tollgates will also have higher capital cost estimates than were assumed in the Study, for the same reason; and this will be revealed as well. In fact, this will be revealed very early in the project. However, until this is revealed to be a terminal obstacle the point of the project is to get a nuclear plant under construction on DOE's 2010 schedule.

3. On another matter, VA's opinion is that government loan guarantees are absolutely required in order to fund construction of the plant. We certainly agree with the assessment that

government loan guarantees may be an essential element of success and would like to see such guarantees as well. However, this is the sticking point for all the studies we've seen on this issue, and this Study is an attempt to find a way to get a nuclear plant built without being held hostage to federal energy legislation The analysis we've done did not assume government loan guarantees and it revealed that there is a potential for the plant value drivers to result in an economic nuclear plant without such guarantees (i.e., by capturing the option value). We are the first to admit that there is just as much potential for downside as upside; but the potential for downside has frozen the industry and has removed a component of energy policy that may be important in the coming years. For instance, one of the upsides that is possible is the passage of federal legislation to cap carbon or other fossil-based emissions would likely result in ERCOT market prices that would make the TGCN plant economic immediately and provide sufficient revenue margin to accommodate investor's risk and return requirements.

Our response to this risk is to treat it aggressively and immediately upon execution of first tollgate. The outreach effort is designed to line up the plant stakeholders; to gather political strength using the Calpine model.

The Value Analytics report follows in it's entirety.

VALUEANALYTIX **Task 7**

Objective: To evaluate the prospects for securing private financing to build and operate a new, advanced nuclear power plant in the deregulated Texas electricity market. Further, if the scale of financing required could be made available to a private developer for this project, to consider what financing strategies and structures might be appropriate or required.

Methodology: The analytic approach employed by the DOE/TIACT/EnergyPath team has been to:

1) Evaluate the economics of a new nuclear electricity generation plant compared to the economics of other electricity generation alternatives, this was pursued by constructing a series of separate financial models for each of the three primary reactor offerings (AECL, GE, Westinghouse) as well as for gas, combined cycle, coal, clean coal, and both on-shore and off shore wind projects. Each of the models used for this comparative analysis has more than 2,000 variables;
2) Informal surveys of energy industry and academic opinion leaders;
3) Informal surveys of financial advisers and industry executives with relevant experience in the equity and credit markets related to large-scale energy projects. Opinions were sought from advisers and executives in the US, Canada, United Kingdom, Finland, Switzerland, Japan and France; and
4) Extensive desk research, notably, reviewing other relevant recent studies from MIT, the University of Chicago, Harvard, Dominion and Sculley Capital, as well as industry specific research reports and reference materials, together with testimony and reference materials developed for and presented to the US Senate, House of Representatives, and the Department of Energy.

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Financial Viability

On the basis of the analysis in the reference case described in Task 6, the all in costs of the plant from inception to operation are slightly more than $3 billion, for a plant with a rated capacity of 1320 megawatts, committed over a 9-year period from 2005 to 2014. The reference case assumption is a 50:50 debt / equity structure with a real weighted average cost of capital of 9%. The interest during construction is estimated to be $410 million of the $3 billion total cost. The core assumption underlying this analysis is consistent with the US Energy Information Agency's forecast that there will be no real increase in electricity prices in ERCOT in the next 25 years and that inflation will average 2.5% per annum over that period. The end result of this analysis is a *negative* net present value (NPV) of approximately $100 million.

As a basic investment proposition this analysis provides a straightforward answer to the question of whether or not this plant can be funded privately, and the answer is no.

However, if a plausible case can be made for changes in the core assumptions, that is, the underlying economics of the reference case, the project NPV could change significantly. It is not automatically the case that all changes will result in a positive change for the project NPV as will be illustrated when we consider the discount rates used in the reference case.

In our view, one or more changes in the reference case assumptions is probable and some of the events which could change these reference case assumptions include:

- Advances in the COL process which could change the capital costs and reduce the time to completion;
- Advances in construction techniques, specifically more success with modular construction, which could reduce the capital costs and time to completion;
- Prospective changes in the U.S. regulatory, legal and financial environments (e.g. from a new Energy Bill) notably a government guarantee for the debt financing of the first 10 new nuclear power plants in the US;
- The probability of a paradigm shift in US energy pricing resulting from greenhouse gas emissions legislation (Carper or a successor bill) coupled with the impact of rapidly decreasing supplies of North American natural gas production and delays in approvals for LNG facilities which will boost electricity prices;
- The end of the glut in Texas of generation capacity by 2010;
- Together with the continuing growth in demand for electricity, which continues to outpace conservation efforts.

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As some of these issues are resolved and future electricity market prices come more into focus, a plausible case can then be made to investors that a new Texas nuclear plant will become a positive NPV proposition. However, achieving a positive NPV from an analysis driven by a 40 year forecast will not automatically make this financeable as public and investor skepticism remains high.

Consequently, the rates of return that determine the plant's cost of capital, will probably be higher than those currently estimated in the reference case.

Project Analysis vs. Capital Raising

The core analysis in the Task 6 reference case is developed from the perspective of a single investor or corporation and their risk adjusted return requirements spread over the entire life of the project and plant. While this is sound practice and common in the internal capital budgeting disciplines of large corporations, we believe that this will not be the path followed by a new, privately held, nuclear plant in the deregulated Texas marketplace.

Given the barriers to building a new nuclear power plant in the United States, we believe that any plant likely to be up and running before 2020, is more likely to be developed by a new company driven by entrepreneurs, created specifically for the task of building this plant. Further, for any group to succeed in breaking the nuclear logjam they will have to behave more like Silicon Valley entrepreneurs than big corporate entities and that will include recognition that they will have multiple rounds of finance.

The primary reasons for this view are:

1) The legal liability, non-nuclear utilities or consumers are unlikely to chose to take on nuclear risk for their company and directors. Utilities with nuclear assets are currently engaged in license extensions and industry/plant consolidation in the US where they can acquire and improve existing plants and generate better returns than those currently offered by new construction so they will not be active participants for at least 5 years;
2) The sub-set of probable investors for this project, notably for the first tranche, are more likely to consist of investors who are particularly attracted to nuclear because of the impact on natural gas supplies in Texas or for other similar reasons; and
3) Culturally, there is no established plan to follow and a management team that could succeed is more likely to be characterized by creativity, ingenuity and adaptability rather than one which may be accustomed to working in the more methodical, 'straight-line' fashion, than has previously characterized most of the US utility industry.

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Financing Sequence

We believe that the plant is likely to be funded in at least three tranches and that the ownership structure will evolve in a manner that resembles a venture capital undertaking more than the standard project finance approach the might be used for a gas pipeline or a rapid transit project. Each tranche will attract different investors with varying risk / return expectations. Each phase would also have significantly different debt/equity levels with the overall result that the weighted average cost of capital in each tranche will vary significantly.

Based on the figures in the reference case, our estimates of the cash requirements, debt / equity structure and costs of capital for each of the three tranches would be:

Tranche 1 – $100 million for the initial planning and the cost of securing a Combined Operating License. Ideally this would be an outflow from 2005 to 2009 but it is unlikely to generate any returns until the refinancing in 2014, consequently it needs to be viewed as a 9-year investment horizon. This tranche would be 100% equity funded, as there would be no immediate assets for debt holders to secure against. The expected return would be in excess of 20% per annum, compound.

Tranche 2 – $2.6 billion for site acquisition and preparation, construction, the initial fuel load, interest during construction and the initial working capital requirements (e.g. training, recruitment and related materials costs) for the sample 1320-megawatt plant described in Task 6. As part of the interest carrying costs, the contingency factor and the developer's retention of the full payment until the plant was operational.

The current reference case assumption is that debt would be financed at the prime rate plus 5% as a risk premium for nuclear construction risk. (For the analysis in Task 6 this rate has been adjusted from nominal to real terms. In Task 7 we are focused on external investors and investors, in general, are more comfortable using nominal figures when assessing investment opportunities; consequently in Task 7 all figures are nominal except where specifically indicated as real.) It is further assumed that a 50:50 debt / equity is used as this is consistent with the debt equity figures for US utilities with nuclear assets.

The nominal cost of equity of 10% is, in our view, not achievable. It is more likely that investor expectations would be in the 12% plus range given the disappointing investment history of some nuclear power projects.

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Regardless of the cost of debt or the cost of equity estimates used in the analysis, we are concerned that at this time it may not be possible to raise all of the financing required for the construction of a new nuclear power plant in the US, without a government debt guarantee. Investor reservations are primarily due to fears about government regulation, the US legal system and environmental objections rather than fears about waste disposal, security or radiation issues, which are all problems for which solutions currently, exist and industry participants know their expected costs.

Tranche 3 – $ 400 million to settle the final payments to the construction firm and reactor vendor plus the initial contribution to the decommissioning fund. These payments would, roughly, coincide with a refinancing of the whole project to lower the debt and equity costs of the construction. Once the plant reached the stage of full operations, the equity and debt costs would fall dramatically with equity costs that could be below 10% and debt costs under 6% with a 75:25 debt/equity level.

Cost of Capital

The discount rate, cost of capital, or hurdle are all terms that refer to the weighted average cost of capital (WACC) i.e. the weightings of the debt and equity applied to discount a project's future cash flows.

All WACC figures are estimates. While formulae, models, data, and statistical analysis are very useful in enhancing the reliability of these WACC estimates, at the end of the day they are all still estimates requiring practitioner Judgement.

By employing some well-developed and accepted principles of modern finance we can develop estimates that are reasonably reliable. The first step in a disciplined approach to estimating WACC's is to decompose the three key dimensions, which are:

1) The weighting of debt and equity or the capital structure;
2) The price of debt; and
3) The price of equity.

Capital Structure

In 99 cases out of 100, debt is cheaper than equity. This is true for two reasons, 1) debt has a lower risk profile than equity – debt has a prior claim on the assets whereas equity has only a residual claim and is therefore riskier than debt; and 2) debt enjoys a more favorable tax treatment which lowers the net cost of debt for earnings positive companies. (While taxation of dividends has dramatically improved and changed this relationship since 2003 in the US, the cost of debt remains lower than the cost of equity.) However, capital structure theory has taught us that this proposition is not infinite. As levels of debt rise, the price of incremental debt rises with the debt increase. Further as both the debt level and the cost of debt rise, equity investors also increase their expected returns on their equity.

Optimal Capital Structure analysis takes this understanding further by iterating through a range of debt/equity weightings considering the cost versus the benefits. In the case of the second Tranche of the nuclear power plant proposal we believe that a 75:25 debt equity structure approaches the optimum capital structure for this process. However, this is only achievable if there is a government guarantee on the debt component.

	Cost of Equity	Cost of Debt	WACC	NPV
Reference Case – Sec. 6	10.5%	9.75%	10.1%	-100 million
Reference at 75:25	10.5%	4.75%	6.2%	- 18 million
Task 7 @50:50	15%	9.75%	12.4%	-201 million
Task 7 @75:25	12%	4.75%	6.5%	+ 92 million

As the chart above illustrates, the impact of the government debt guarantee would be to allow the project to have a higher percentage of debt at a much lower cost with the result that in an NPV format this moves the project from being a negative NPV proposition to being a positive NPV proposition.

Debt Pricing

There are two primary debt considerations in any debt raising activity, the creditworthiness of the borrower and the price.

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A nuclear plant, which has a license and is under construction, is, based on past performance, a risky proposition. Any normal credit evaluation would quickly conclude that in the event of default there would be no assets to seize to recover against the debt. Consequently, the loan would not be made or the bonds would not be underwritten. Two alternatives exist to the developer, to supply other security as full coverage in the event of default or to obtain a government guarantee for the debt.

In gas, hydro or other energy projects banks will often accept a Power Purchase Agreement (PPA) as a measure of creditworthiness of the project. However, given the long construction lead times involved and the extremely low probability that any counter party to a PPA would pledge their assets in the event of default, a PPA or series of PPA's is not a viable course in this case.

On the issue of debt pricing the reference case assumes that it will be 5% above the prime rate, which would place this debt firmly in the 'junk' classification. If it did prove possible to get over the credit hurdle to proceed, and assuming a 50:50 debt to equity relationship, the interest during construction costs would be in excess of $410 million for Tranche 2.

Obviously with a government guarantee the debt would be at a much lower rate of interest, probably yielding something around 1% over comparable treasury bonds, which would reduce the interest during construction costs by roughly 50%.

Equity Pricing

The equity price reflects expectations of future returns and as such is subject to the same issues as is any forecast. Estimates of the cost of equity can be approached using models such as the Capital Asset Pricing Model (CAPM, a model for which William Sharpe was awarded a Nobel Prize in Economics) or Arbitrage Pricing Theory (APT). Equity estimates can also be derived from investor surveys or by simply asking boards or groups of investors what they want for a return from a specific project.

For traded companies, or businesses where there are reasonable comparable investments, CAPM and APT, provide the most reliable estimates while opinion surveys generally produce the least reliable estimates. This leads us to a marked preference for CAPM or APT; but a difficulty arises in applying either formulation in that there is no comparable US nuclear power data to draw on. This makes the estimates for Tranches 1 and 2 difficult. For Tranche 3 there are a number of good and reliable examples that allow us to reasonably estimate these prices as there are clear comparables operating in the US and other markets.

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As previously noted, we believe that there are three different phases to this project and that it would be necessary to have at least three tranches of finance and that the expected equity returns will change dramatically depending on which stage we are in as well as the price and proportion of the debt component of the capital structure.

In the first financing tranche the WACC is probably 20% as it is a high risk, all equity proposition. This is an expected return as high or higher than the rate, which might be applied, to a biotech or software development investment. On reflection this is probably realistic as there are two primary risks, which could mean that $100 million goes in and nothing comes out. The first of these is that if the COL application is unsuccessful because of regulatory issues, legal issues or environmental objections (there isn't any significant engineering or technology risk) then 100% of the investment will be lost. Further, the company could secure the combined operating license but the economics continue to be unattractive and as a result the COL's value is small or zero. By contrast, even failed software or biotech firms usually have something to show for their efforts. Further, in technology investments it is possible for scientists, engineers and others to assess their prospects for success more readily than investors can assess an untried COL process combined with the unpredictable nature of the US legal system and the volatile nature of public opinion.

For the construction phase through to full operation the expected equity return will be lower. Former NRC Commissioner and currently a Managing Director at Lehman Brothers, Jim Asselstine, suggests that this is likely to be in the 12 to 15% per annum, compound, range, and we think that this is plausible. As noted in the prior section we think that with a government debt guarantee and a 75:25 debt/equity level that 12% would be reasonable even though it is counter-intuitive that the equity rate would be lower with a higher debt level in the project. In the absence of the government debt guarantee the cost of equity is more likely to be at the high end of the range, 15%, and that higher rate would be applied to 50% of the capital structure.

In the third tranche, post completion, when the plant is fully operational we believe that he project/company could be refinanced at significantly lower costs. The expected equity rate of return would come below 10%, the 75:25 debt/equity could be supported by the plant's cash flows and the debt price could be in the 6% range without a government guarantee. This would produce a WACC that could be as low as 7%.

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The Nuclear Premium

We believe that in the US capital markets the first 10 nuclear plants will all be subject to what we believe is a “nuclear premium”. The nuclear premium is the abnormally high returns that debt and equity investors will demand to compensate for the systematic risks that they perceive in US nuclear plant construction. We don’t believe that technology, engineering, safety, security or waste disposal issues are showstoppers. The only “show stopper” in our opinion, are investor concerns about the untested COL process, the responsiveness of the Nuclear Regulatory Commission, the US and state legal systems and some very small elements of public opinion. The vagaries and unpredictability of these factors are in our view the prime contributors to the nuclear financing premium on debt and equity fundraising.

If the issues for investors were technology, waste, or the economics of nuclear power and not US centric issues about the US legal system, regulation and public opinion, than these same issues would prevent construction of nuclear power plants in other countries but they haven’t. There are currently in excess of 80 nuclear power plants around the world in development or under construction. These plants are in Finland, France, India, Russia, China, Japan and other countries where the financing “nuclear premium” is either non-existent or much smaller than it is in the United States. The “nuclear premium” is demonstrably not about technology.

Adjusted Present Value

In assessing the economic viability of the proposed Texas plant the focus of the report has been on the net present value. However, when we apply our three tranche financing model we need to alter our formulation of the economics and for that purpose we use an Adjusted Present Value (APV) formulation.

Adjusted Present Value (APV) is a technique almost identical to the Net Present Value (NPV) in that both are discounted cash flow techniques. The only difference between the two calculations is that with an APV calculation we employ multiple discount rates whereas with an NPV calculation it is more common to use a single discount rate for both the forecast period and the residual calculation.

When we apply the different discount rates for the three tranches of capital as discussed above, we get the following result:

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Using APV we modeled the plant as two projects using the reference case (Ke is cost of equity) .

Stage 1:	Licensing and Construction	Ke = 15%	(2005-2014)
Stage 2:	Operations	Ke = 10%	(2015+)

The Value of Stage 1 (Tranches 1 & 2) adjusted for risk in today's terms is –$948m.
The Value of Stage 2 (Tranche 3) adjusted for risk in 2015 terms is $1423m.

To make these figures comparable we need to express them both in 2005 terms which we do by discounting Tranche 3, at a risk free rate, from 2015 to 2005 which takes the value from $1423 to $998 million.

The total APV value of the project then becomes $-948 million minus $998 million for a net positive of $50 million.

We then revisited this APV value by allowing for the impact of a government guarantee on the debt. Under this scenario the value of Stage 1 (Tranches 1&2) improves from a negative 948 million to a negative 883 million. While the value for Stage 2 (Tranche 3) remains at $998 million in 2005 terms, because we assume that post construction there would be no government debt guarantee, the APV for the whole project increases to US 115 million.

Government Debt Guarantee

We believe that private investors are not going to fund a nuclear plant in the United States because they are unwilling to accept US government/legal risk at this time. If the government of the United States decides that as a matter of public policy that the United States needs additional nuclear power to:

- Reduce Greenhouse gas emissions,
- Diversify the supply of electricity production;
- Add generation capacity that is available when the wind doesn't blow and the sun doesn't shine; and
- Reduce dependence on imported fuel, notably natural gas.

Then it will have to take a risk on nuclear power by providing a guarantee for the debt during construction.

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While it was ludicrous for a former Chairman of the Atomic Energy Commission to say in the 1950's that nuclear electricity would be so cheap you wouldn't even have to meter it, the analysis in this report is based on pricing assumptions that this plant would produce reliable electricity at a cost point comparable to coal plants and less cost than so-called 'clean coal'. Part of keeping the cost of the electricity down will be to keep the capital and financing costs in check and the government can do that without actually imposing a cash cost on the US taxpayers. We say this because over the past 9 months we have developed a confidence in the vendors, contractors and others that the plant would not default on the debt and therefore the taxpayer would not be called on to pay out any hard tax dollars in the manner that they have been forced to in the past through rate based increases in electricity prices or payments for failed projects or payments for "stranded costs".

As a matter of public policy we are confident that the case can be made that it would be in the best interests of US taxpayers to actively encourage the renewal of the US civil nuclear industry. As a matter of public policy there is some urgency to this as the lead times for nuclear power are obviously very long. To encourage the construction of new nuclear power plants we would strongly recommend a government debt guarantee for the first 10 nuclear power projects that meet all of the following criteria:

1) That they have obtained a COL from the NRC;
2) That they have Power Purchase Agreements for at least 50% of the plant's generation capacity before they begin construction;
3) That they commit to construction beginning prior to 2012; and
4) That they have raised a minimum of $500 million in private equity funding prior to raising any government guaranteed debt.

Conclusion

Construction of a new nuclear power facility in the Texas market will only occur if there is the prospect of electricity prices rising in real terms over the next 25 years, and if reactor vendors provide fixed price construction contracts for advanced nuclear plants. To break the logjam that currently exists in development and sponsorship of new nuclear plant construction will require the Federal or relevant State governments to provide a significant debt guarantee. Further, to navigate through the uncharted waters of the COL process and the daunting requirements of financing this scale of activity will require the electricity generation industry to attract developers with management and business styles more commonly associated with Silicon Valley entrepreneurs than the business styles more commonly ascribed to the US utility giants.

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TASK 8

ESTABLISH PROJECT RISK PROFILE

TASK 8. ESTABLISH PROJECT RISK PROFILE

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TASK 8. ESTABLISH PROJECT RISK PROFILE

8.1. INTRODUCTION

A key objective of this study is to create a roadmap for TIACT members and other interested parties that identifies and describes the actions needed to deploy a new nuclear plant in Texas. This roadmap represents the collective results of Tasks 2 through 7. In the reports on each of these tasks, we identified and discussed qualitatively the many risks that would confront the project management team working on behalf of the plant owners.

In this Task 8 we attempt to quantify these risks and lay out a plan to manage them. This will add substance to the prospectus and increase the appeal of the three proposed tollgates.

Several risks have already been identified as being managed through the tollgate process, described in Task 6. These include the uncertainty surrounding EPC costs, COL costs and the cost of capital during construction. In this approach, these costs must be sufficiently firm to justify passing the subsequent tollgate.

Most of the other uncertainties in the project are realized after substantial capital has been committed, such as market prices (revenue), capacity factor, production costs (including refueling outages), and the construction schedule and cost. Each of these, if not managed, can have a negative impact on the plant's economic viability. For that reason, the risk management plant can be described as plan to "contain" the value that has been built into the plant.

Risks that are managed through either the tollgate or an active risk containment strategy are described in this Task.

8.2. PRINCIPAL FINDINGS

The principal findings of Task 8 are as follows:

1. One of the principal reasons that new nuclear plants are not being ordered and constructed is because potential owners see too much nuclear-unique risk exposure. This view is founded on the painful experiences of the last round of nuclear construction which was not viewed favorably by the financial community. The risk management plan described herein addresses many of these concerns, although it is impossible, of course, to eliminate all risk from the project.

2. The tollgate process resolves some major risks long before large amounts of capital are committed. Other risks cannot be managed through the tollgate process; and need further attention. One risk can only be moderately controlled prior to capital commitment, and that has to do with cost caused by delays during construction—not the EPC costs which will be firm priced by the suppliers; but rather the additional costs incurred during construction, such as interest during construction. While the business and project management components of construction can be managed, and are routinely controlled by large construction firms, the risks associate with the legal and regulatory process are not as amenable. Further, it is believed that the greatest driver of this risk component is the potential for a legal challenge at the later stages

of construction which could delay construction significantly after several billion dollars have been invested. The issue of government loan guarantees for the earliest nuclear plants is frequently cited as the only means to control this risk; and that may be true. However, risk can also be allocated through private capital markets (albeit at a very high price) and it should not be concluded that government loan guarantees are the only way to control this risk. Further, if government loan guarantees are the ONLY vehicle for moving forward, then the prospects for a new nuclear plant become hostage to the passage of this legislation.

3. The risk that total overnight capital costs will be too high is taken into account in the tollgate structure. By resolving this as the first order of business when the least amount of development capital is expended the risks can be kept quite manageable.

4. The plant is expected to be a top quartile performer. Thus, both lower-than-expected capacity factors and higher-than expected production costs represent risks that are able to be influenced greatly by the plant owners. Both of these risks have serious downside potential which could impact nearly $300 million of plant present value, although this is considered unlikely. Outsourcing to top quartile nuclear operators with incentive-based contractual structures is the recommended approach to keeping capacity factors and O&M at top quartile performance levels.

5. The risk most often mentioned by potential investors is the currently unresolved high level waste solution. Our studies validate these concerns and estimate that an average risk premium of about 0.6% (real) could be used by investors to value the plant if they believed that the costs would ultimately fall to the plant owners. It is expected that the DOE will continue to take responsibility for finding a solution to the issue, and, in any event, will have the responsibility for disposition of all spent fuel.

8.3. IDENTIFYING THE KEY RISKS

We begin by ranking the various risks in terms of their relative contribution to the variability of plant NPV. From highest to lowest these are(the numbers in parentheses provide a measure of relative impact on NPV variability):

- Higher than expected Engineering, Procurement, Construction (EPC) costs (62%)[1]
- Volatility of electricity prices and hence revenue stream (11%)
- Delays during construction (10%)
- Lower than expected capacity factors (8%)
- Higher than expected production (fuel and O&M) costs (7%)
- COL licensing risk (failure to get approval on expected schedule) (1%).

1 EPC Costs are the major component of total overnight capital cost.

The contribution of each to the total risk is visually displayed in the Pareto chart, Figure 8.1, below

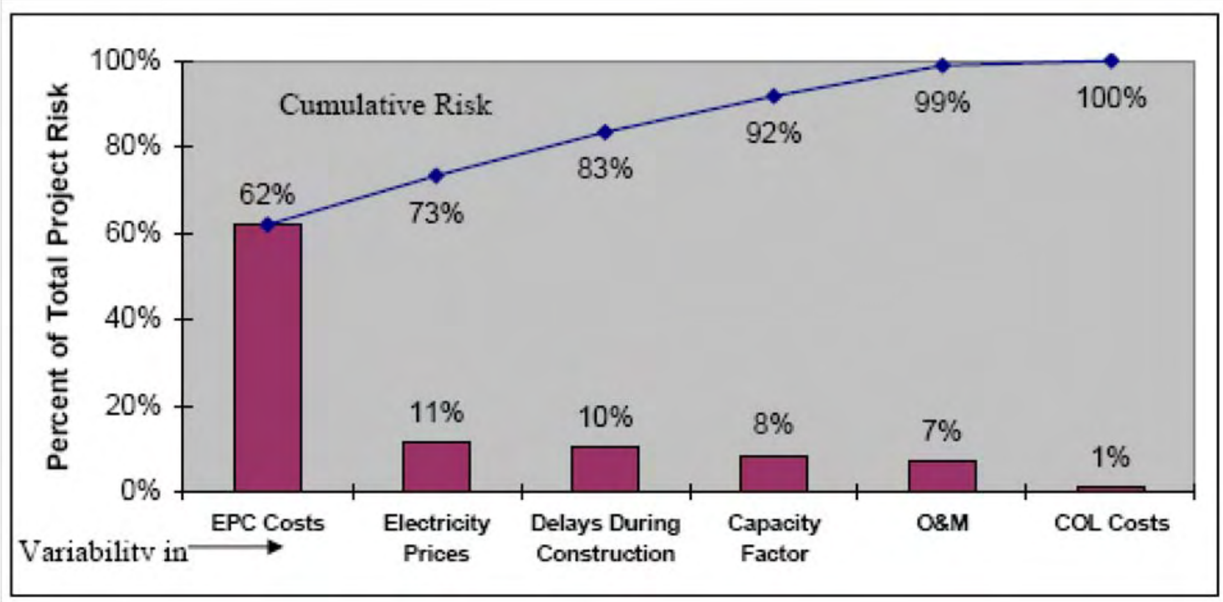

Figure 8.1. Sources of Variation in Plant NPV (Pareto Chart)

8.4. THE RISK MANAGEMENT PLAN

When reviewing a prospectus a potential investor will look for information that answers two questions(1) How much money can I make; and (2) What is the risk of losing money? As has been made abundantly clear, this project entails a significant amount of risk. This is the reason that a tollgate approach is recommended prior to making the final decision to construct the plant. The tollgate approach allows for time and funds to resolve uncertainties prior to making a final commitment to undertake the startup costs, the cost of the COL application and, finally, the investment in the plant.

As a starting point, Table 8.1, summarizes the chief strategy being used to manage the risks. Risks that can be controlled directly are reflected in the tollgate plan. Risks that can erode the value of the plant after construction has begun are managed through a very specific risk containment strategy, and are described below.

EPC Costs[2]

Just as the cost of natural gas is central to the economic competitiveness of combined cycle plants, capital costs are the key consideration for nuclear plants. Roughly, capital costs are 75% of the total

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2 EPC stands for Engineering, Procurement, and Construction. The EPC costs are those stipulated in the supply contract and do not include owner's costs or financing costs. Owners' costs comprise site preparation activities such as transmission, cooling water, etc.

cost of electricity for a nuclear plant,[3] making the profitability of the project quite sensitive to capital costs. A 1% increase in total overnight capital costs produces a decrease of 1.3% in the plant NPV.

Table 8.1. Summary of Risk Management Strategy

Risk	Management Strategy
Total Overnight Capital Cost	Tollgate #1
Electricity Prices	Tollgate #3 & Risk Containment Plan
Delays During Construction	Tollgate #3 & Risk Containment Plan
Capacity Factor	Risk Containment Plan
O&M	Risk Containment Plan
COL Costs	Tollgate #2

In this section we will consider the risk associated with the main bulk of total overnight capital costs, the EPC costs, defined as the costs to engineer the plant; procure the components, equipment, material, and labor; and to actually construct the facilities. An easy way to think of it is as the price given in the prime contract for the supply of a nuclear "unit" (reactor building radwaste facility, and turbine building).[4]

EPC costs represent the single greatest risk to the project's viability because there needs to be a substantial decrease in EPC costs from the most recent round of construction. If not, then there is little hope of a nuclear revival in the U.S. in the near future. Further, the project is very sensitive to EPC costs. At the current levels of NPV (-$100 million), a 10% decrease in average EPC costs ($1395/kWe) would result in a 70% increase in the plant's NPV (-$48 million).

To actively reduce this risk it is necessary to fund the acquisition of EPC cost information, and to finalize to what scope and price the suppliers will commit. The information in this case is additional design detail[5] from which more complete cost information can be prepared. Current industry initiatives being co-funded by DOE (other than this project) include engineering design efforts: NuStart (AP1000 and ESBWR), Dominion (ESBWR), and TVA (ABWR).

While these are important initiatives, it is our opinion that until a supplier enters into a firm price contract for a plant built in the U.S., the contingency level will be at best 5%. We know from experience that additional engineering information does not lead to more cost certainty and that

3 When natural gas is at the $5 per MBTU level it accounts for 75% of the total cost of electricity generated by a combined cycle plant with a heat rate of 7000 MBTU/kwhr.

4 As opposed to a nuclear "plant" which includes one or more units and the site infrastructure such as switchyards, warehouses, machine shops and water intake structures.

5 The multiplier is 1/k where k=1/(I/V) – 1.

even if the design is 90% complete there will still be a considerable risk that actual, as-bid costs will be higher than estimates quoted publicly. The reason is that the various elements of costs—the plant supplier's own costs and those quoted by the over one hundred sub-suppliers—do not take into account commercial terms and conditions at the pre-proposal stage. In addition, vendors at this stage prefer to provide as low an estimate as is reasonably possible in order to avoid the perception of being non-competitive, a perception which if hardened will likely rule them out from future consideration.[6] Finally, the designs of the turbine islands, including that of the turbine-generator itself, are generally out of date because there has been little incentive to maintain or improve these designs for the U.S. market. These costs are estimated with little detail to back them up.

The "traditional" approach toward new plant projects is to prepare the COL application, submit it to the NRC, support its review and then, with COL in hand, go out for bids. Only then would one know with any reasonable degree of confidence—that is, without being subject to undue risk--if the project met the financial targets set for it by investors.

With the likelihood that ordering a new nuclear plant in a competitive market is not going to happen in the "traditional" manner, a better way to attack this risk is to go out for bids at the very outset (the first tollgate is passed when funding is secured for the EPC bid and negotiation process). This would be well before any sizeable financial resources and several years of effort are expended on the COL process). We recognize that securing this financing will be a challenge.). Nevertheless, as discussed in Task 7, raising any funding at this stage of the project will be quite difficult, and the funds are likely to be very expensive. Passing the first tollgate will not be easy.

Here are the six steps in the total overnight capital cost risk management plan:

(1) Update EPRI's Utility Requirements Document (URD) for use as the technical and performance-related bid specification guideline and customize it for the Texas project (2005-06)

The URD was written for just this purpose and, moreover, has been used by both Taiwan Power Company and TVO of Finland as bid specifications (although in the latter case the specs were adapted from the European Requirements Document, which is modeled closely after the URD.) Thus, the project management team would have a ready and available set of mostly technical bid specifications. An engineering firm with nuclear experience would be hired by the team to update and customize the URD for use as bid specs for the Texas project.

(2) Issue a Request for Proposals (RFPs) for a total plant on a firm price, firm schedule basis (Early 2006)

Most of the plant suppliers have indicated a willingness to provide plants on this basis. Their earlier reluctance to do so has given way to the recognition that plant owners do not have the capability (by way of people left over from the last round of new build in the US) to manage such a complex

6 This appears to have happened with the ABWR, most likely because of unfavorable comparison with other plants for which some very aggressive numbers have been published. The cost numbers used in this study do not support a conclusion that the ABWR is more costly than the other options.

undertaking. Also, there is no way that early nuclear plants are going to be able to move forward with financing without knowing these costs.

(3) Prepare a set of terms and conditions appropriate for the supply of a total plant with a firm price and firm schedule (Mid 2006)

Although plant suppliers will team with numerous parties to deliver a total plant scope[7], the consortium will want to have a single contract that will likely be with the reactor supplier acting as the prime contractor or with a joint venture of the reactor supplier and another supplier with a large project scope (possibly the constructor). Risks will be allocated to those parties in the best position to control and mitigate the risk. There will be at least one risk that can't be controlled by either party—delays during construction. As discussed more fully in the report for Task 4, we are referring to the possibility that an intervener halts the project pending court action or that the NRC does not hold to its processes (ITAAC and one step licensing) during construction).

(4) Review the bids and select a supplier (Mid to Late 2006)

This is a four to six month effort; including a review of the proposals; selection of one supplier for negotiations and selection of a supply team, assuming that the plant economics prove positive. The same engineering firm that prepared the bid specs from the URD could be used to perform the technical review.

(5) Enter into a binding contract (Early 2007)

The purpose of all this activity is to enter into an exclusive contract with a supplier that 1) commits the ownership consortium to ordering the plant when and if the construction option is exercised; and 2) commits the supplier to build the plant at the price agreed to in the contract and under the terms and conditions of the contract. These terms and conditions will, as always, specify important qualifiers such as price adjustments for inflation, unforeseen regulatory action and liquidated damages.

(6) Provide partial funding to bidders (2005-06)

Plant suppliers incur a fair amount of costs to write a proposal. Such proposals take three to six months and several million dollars to prepare. Although we would like to think that suppliers would be willing to incur this expense as part of the cost of doing business, it is unrealistic to expect them to do so for two reasons. The first is that the Texas Gulf Coast Nuclear plant consortium, although committed to proceeding with the construction of the plant, cannot put a contract into effect unless

7 The prime contractor would be responsible for putting a supply team together. It is expected that the reactor supplier (e.g. GE, W, AECL, FANP) would assume this responsibility. In addition, the reactor supplier would provide all or most of the nuclear island, using sub-suppliers for major components and equipment, and the initial core of fuel and a few reload batches. An engineering firm such as Black & Veatch would be responsible for the turbine island supply, which would likely include procurement of the turbine-generator set (alternatively, the prime contractor might procure this.) The third member of the supply team would be the constructor, the party responsible for erection of the buildings, site preparation, construction of necessary site infrastructure and overall construction management.

the capital costs meet its financial targets and not until a COL is issued; and 2) it is by no means assured that there will be a long term market to warrant such an expense should the Texas project not proceed.

The cost of this effort is roughly estimated to be ~$10M and the time needed about 12 months. The details are shown in Table 8.2.

These costs would come out of the first tranche of capital raised by the consortium and other equity investors in the project and would be incurred at the very outset of the development phase of the project.

The benefit, is that the EPC component of the total overnight capital costs would at that point be known and a significant risk item would either wholly or partially be resolved. The value of eliminating this uncertainty at the outset of the project rather than waiting until after the COL process is complete is approximately $55 million.[8] Since the costs involved in discovering with certainty the total overnight capital costs is about $10M-$12M (see Table 8.2), then the cost benefit ratio is favorable.)

Table 8.2. Estimated Costs and Schedule of Proposal Activities

Activity	Months	Estimated Costs (Millions)
Prepare bid spec	3	$1.0
Prepare proposals	3-6	$5.0 total per bidder $2.5 by consortium $2.5 by the bidder or DOE
Review proposals	3-6	$1.0
Negotiate contract	3	$0.5
Contingency of 20%		$2
TOTAL (for 3 bidders)	**12-18**	**$12M (Consortium only)**

Delays during Construction

Next we will consider the risk that interest during construction will be higher than expected due to delays in the construction schedule. Such delays could arise from many sources, including the following:

- Suppliers do not meet their schedule commitments;

8 The $57M result is determined from the real options model by eliminating the opportunity to exercise the first option. Then the total overnight capital costs will need to be determined in the lead up to exercising the construction option. The value of having the first option is the opportunity to abandon the project prior to spending the $150M exercise price in the event that the capital costs are too high.

- The NRC does not conform to its new ITAAC[9] inspection process;
- The project is halted or delayed because of a legal challenge and possible court injunction.

The financial impact due to a delay in construction is, of course, higher interest costs. The later this occurs, the worse the consequence because the cost expenditure pattern when plotted over time shows a very steep "S" curve. A delay that occurs just six months before commercial operation is particularly devastating because 95% of the total cost has been incurred—over $2.5B.

The worst event that could befall the project would be for construction to be halted and never resumed, especially if this occurred late in the construction cycle. It is this possibility that is the primary concern of investors based on the investor CTQs and conversations with the financial community (see a description of the investor CTQs in Task 6).

This risk, of course, will be very difficult to manage to the satisfaction of the plant's investors, who may have to make capital funding decisions without the security of knowing if the construction of the plant will set off a firestorm of controversy and activism. There may be early resolution of this if evidence is gathered before construction that resistance is likely (tollgate #3). However, unless there is a definitive legal ruling that would eliminate the possibility of a construction halt, investors will continue to see this investment as quite risky (see the discussion with investors-the investor CTZs - in Task 6).

This risk would be eliminated (at least for the debt holders) through the passage of legislation that provides government loan guarantees. However, there is no assurance that such legislation is forthcoming. We would welcome such legislation and encourage the Congress to resurrect this component of national energy policy. We would envision this "backstop" would cover the construction debt (not equity), be capped at 100% of the total construction debt facility, and be exercised only in a limited number of circumstances–protracted ITAAC process, delays resulting from court actions over legal or regulatory issues; but does not cover business risk issues. The economic analysis shows that when the government provides a backstop the expected net present value undergoes a dramatic shift from -$100 million to over $100 million- a $200 million difference and enough to make the nuclear plant economically viable. This occurs because of the reduced cost of debt capital and a higher percentage of debt in the capital structure when government assumes construction risk.

While welcome, we don't feel that the nuclear industry should leave itself hostage to the passage of such legislation. This Study is an attempt to move forward immediately without the need for such legislation.

While this is clearly the most pressing risk related to construction, one of the important tasks before the consortium is to explore is to address alternatives.

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9 ITAAC stands for Inspections, Tests, and Acceptance Criteria. It is the process by which the NRC verifies that the plant is built in conformance with the Design Certification, specifically, the design information contained in the Design Control Document that exists for each certified design. The DCD is prepared by the supplier and approved by the NRC at the time the Design Certification is approved.

(1) *Contract with the supplier for firm Liquidated Damages (LDs)*
Most suppliers have expressed a willingness to provide LDs. For instance, the contract would specify a number of schedule milestones, such as the delivery of the reactor pressure vessel to the site, as hard dates. If these dates were not met, the supplier would pay increasingly higher damages. From an owner's perspective, LDs are not entirely satisfactory because the amount of such damages is much less than the consequential damages of delays (e.g., more interest costs or loss of revenue). However, if the amount of the LDs is significant they will act to motivate timely performance on the part of the supplier.

(2) *Choose on the Basis of the Supplier's Track Record and Commitment*
This is perhaps painfully obvious. However, we make this point because it easy, we think, for potential owners to become enamored with the technology and overlook the fact that the supplier's credentials, experience, network of sub-suppliers, history of providing on-going support should problems arise, and of course reliability will have more to do with the success of the project than the technology.

(3) *Early Community Outreach Program*
One way to address construction delay risk is to reach out to the public and other stakeholders from the very beginning, well before any key decisions, especially the site selection, have been made. We are not comfortable with the approach seemingly taken by other industry members. This approach, it seems to us, is to minimize public outreach and insist that the NRC not flinch under pressure should there be vociferous intervention during the COL review or during construction.

It is recommended that the public outreach program begin soon after the plant ownership is established. The purpose of this outreach would be to provide information to the community, use the resulting feedback to address concerns, and slowly build support for the project all across the spectrum of interest groups. In addition, the outreach would help to neutralize or blunt some of the opposition to the project, especially which is likely to come from nationally based organizations opposed to nuclear power.

This approach has been used to positive affect by Calpine Corporation in getting public support for the permitting of a 600 MW combined cycle plant located in South San Jose, California. Calpine representatives fanned out in the community to quietly raise the subject even before an application was filed with California Energy Commission (CEC). It obtained endorsements first from community organizations and leaders. Building upon this, Calpine added the support of the trade unions, the Chamber of Commerce, the local chapter of the Sierra Club, the American Lung Association, and the local chapter of the NAACP. Although Calpine and representatives from all these interest groups worked laboriously with local elected officials, the San Jose City Council actually voted 10-1 to oppose the project and to deny Calpine some needed permits. However, the CEC overturned this decision (by law it is the lead organization on power plant permitting in California) and one very important reason was the widespread support of the local community. The Calpine outreach program lasted nearly three years and often times seemed doomed to failure. Its annual budget averaged $2M per year.

Table 8.3 shows the costs and benefits of undertaking risk mitigation activities to limit potential construction cost escalation caused by delays (but not complete construction halts). The total cost to undertake the activities is estimated to be about $10M; but they would be addressing the potential for a loss in NPV of as much as ~$200 to $400 million for a construction delay (increased interest costs).

Table 8.3. Estimated Costs, Schedule & Benefits of Risk Mitigation Actions

Activity	Months	Estimated Cost	Estimated Benefit
Early community outreach	24	$6M	
Prepare and argue lawsuit	12	$2M	
Legislative advocacy	12	$0.25M	
Contingency of 20%		$2M	
TOTAL		**$10M**	**~$200-400M (IDC)**

In summary, a community outreach effort represents an insurance policy. There is no guarantee that this activity will be efficacious and there still could be construction delays in spite of these efforts. However, a significant amount of information will evolve in the 5 years leading up to the exercise of tollgate #3. At that time a determination can be made as to whether or not sufficient insurance is in place to prevent a potentially damaging economic blow to the viability of the plant.

Electricity prices

In a perfectly competitive electric market, prices reflect the availability of capacity relative to demand. Over the last several years, prices in ERCOT have reflected the overhang of excess gas-fired generation and electric prices have moderated.

Certainly the current level of electricity prices is not high enough to justify building more capacity; but even more important is the uncertainty associated with issues that affect future electricity prices: What are the market rules? Will there be new and more stringent environmental regulations, including a penalty of some kind on carbon emissions? Will energy policy tilt the playing field in favor of renewable resources?

It is estimated that market price risk could represent a loss of up to $300 million of NPV (admittedly a low probability event that could result from natural gas prices returning to their historical levels) should there be an unexpected reduction in market demand relative to capacity. This is substantial; but it is more widely believed that prices will come under upward pressure as actions are taken to impose environmental legislation on the fossil industry, or as current economic fossil resources are depleted. The pricing assessment used in this Study is quite conservative and does not take credit for large price increases occurring during operation of the plant. They are based on natural gas price forecasts prepared by the Energy Information Administration in its Annual Energy Outlook, which is widely believed to understate the actual level of future gas prices by a significant margin.[10] Nevertheless, it was an objective of the Study at the outset to not depend on high natural gas prices (and hence electric prices in ERCOT) to justify construction of the plant.

As was described in Task 5, it is proposed that an ownership structure based on the “TVO model” be the preferred ownership model for this project. This model has the important feature that it reduces (but does not eliminate) much of the uncertainty related to market pricing, as the end users of the plant are also the owners.

For review, this ownership arrangement, discussed in Task 5 and shown below in Table 8.4 is based on the “TVO Model”. If implemented, this arrangement could help ensure that market price uncertainty did not overwhelm the plant’s ability to attract financing. End users, for example, would enter into an agreement to off-take a portion of the electricity on a cost basis (where costs in this case include debt service and return on equity). Municipal utilities would distribute electricity to their residential, commercial and industrial loads. Because municipal utilities opted out of de-regulation in ERCOT, they have a secure customer base and, more importantly, ratemaking authority.

In the event that the total plant capacity is not subscribed through the proposed ownership structure, some portion of the remaining risks could be addressed through a portfolio of Power Purchase Agreements. However, this might prove difficult, especially since the plant financing must be obtained prior to starting construction, well in advance of the generation of power and the ability to address long term pricing with customers (other than end users owning a plant stake).

Among end users in the chemical industry there are a variety of purchasing practices. Many are interested in long-term contracts (to eliminate the risk to their own profits represented by electric price volatility) and nuclear is well suited to provide long-term fixed prices to this group of end users. Others are interested in procuring the cheapest electricity possible and are willing to accept long-term risk to do so.

10 See, for example, The Wall Street Journal, December 27, 2004 Utilities Question Natural Gas Forecasting (page A2)

Table 8.4. Ownership Shares of Texas Gulf Coast Nuclear, Inc.[11]

Owner	Share	MW
Industrial end users	15%	210
Municipal utilities	50%	700
Generating Companies	10%	140
Private Investor Groups	25%	350
TOTAL	**100%**	**1400**

In any event, it is important to the financial viability of the project that market price risk be recognized and steps taken, where possible, to protect the plant value. There is little chance of attracting finance unless the level of expected cash flow can support the contracted reactor supply's construction costs; and this may not be an issue given the greater potential for higher prices, as discussed. This activity will occupy significant time.

Plant Performance: Capacity Factor

There is compelling evidence, accumulated over many years, that the high capacity factors of nuclear plants in the U.S. are largely the result of good plant management.[12] Forced outage rates, which 20 years ago were quite high (over 7 unplanned shutdowns per 7000 critical hours), today are virtually eliminated as a capacity factor drain. Now, capacity factors are almost completely determined by the length of refueling and maintenance outages, although there are still (increasingly rare) extended outages due to unexpected and often generic technical problems (the most recent incident being that of potential vessel head failures due to boron corrosion.)

For these reasons the capacity factor used in the risk model represent those of a top quartile nuclear performer, averaging around 95% in non-refueling years. Refueling year capacity factors were about 88%.[13]

Shorter refueling and maintenance outages are achieved through detailed planning and scheduling.

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11 As we wrote in the Task 5 report: "This is a reasonable scenario. For end users, 210 MWs represents the load for one or two typical end users. Also, 700 MW is less than the current shares of STP owned by Austin Energy and City Public Service of San Antonio. It would represent only a modest increase in the generation capacity they already own and probably represents two or three years of normal load growth."

12 Most of the recent gains in plant performance have evolved from the incentives provided by wholesale and retail deregulation following the Energy Policy Act of 1992. Today capacity factors for the industry hover in the 90% range from about 65% in the late 1980s. Refueling outage durations are now routinely performed in less than 35 days, whereas less than 15 years ago the median refueling outage duration was nearly 90 days. The best performers are doing these outages in less than 20 days.

13 These were the means. The risk model varied the actual capacity factors according to the observed standard deviation of capacity factors for nuclear plants in the U.S.-about 6% per year.

It took years for the best performing plants to develop the capability to keep their plants running day in and day out without interruption and was often accompanied with major changes in the culture, organizational structure, expectations, compensation plans, and so on. The industry helped itself in this regard by often sharing best practices.

The most obvious risk management plan is to focus on putting together the right management team to maintain the plant at a high performance level. While it could be possible to recruit a strong plant management team to maintain the plant at first quartile performance levels, it is more probable that this will be outsourced. Strong candidates might include Exelon, Entergy or the Nuclear Management Corporation (NMC.)[14] If the new plant were to be located at the existing site of a consortium member, then there is a strong opportunity to build upon the existing plant management.

The recommended action item is to prepare a credible staffing and management plan to accompany and enhance the prospectus and to outsource plant management to a first quartile nuclear plant operator. It is estimated that this effort would cost $500,000 primarily in the way of consulting fees. Alternately, if there is need to limit the amount of development capital put at risk, this plan could be developed after the COL and financing have been approved. In addition, a Long Term Service Agreement (LTSA) with the reactor supplier will almost certainly be executed. Capacity factors in the 90% range instead of the first quartile's 95% values could cost the plant almost $200 million in NPV.

Plant Performance: Production costs

Production costs are the short run variable costs associated with the generation of nuclear electricity, comprised of plant operation, maintenance and fuel costs.[15] As a measure of the relative importance of these costs, average production costs for U.S. nuclear plants are about $17/MWh, which puts it slightly below the production costs of coal plants ($18) and well below that of combined cycle plants ($58). Of this, operation and maintenance costs (O&M) costs are about $12 and fuel costs are $5.

Over the years, non-fuel O&M costs have shown great variability between U.S. nuclear sites and have remained at a relatively high level, decreasing only about 10% since 1992.[16] Unfortunately, these costs are now experiencing upward pressure as security concerns since September 11, 2001

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14 The Nuclear Management Corporation manages and operates seven nuclear units within four states in the upper Midwest. The role of the company is solely to manage nuclear plants, although all of the nuclear plants managed by the company are older generation plants.

15 Fuel cost is actually a capitalized cost and is depreciated on the income statement under "Fuel Charges". The practice in the industry is to treat these depreciated costs as representing an actual cash flow for the purpose of calculating the total cost of generation.

16 This emphasizes the fact that nearly all the gains in nuclear's generation costs have come principally through the strong gains in capacity factor. Actual spending on O&M has decreased; but the decrease appears more dramatic than it is owing to the large increase in capacity factor (the denominator of the $/Mwhr calculation). The same is true of fuel costs.

are causing spending to increase.[17] Nuclear fuel costs by contrast have been quite stable across plants while decreasing about 30% since 1992 (See footnote 17).

Regardless of their increasing rarity, the principal risk associated with O&M costs remains the threat of unplanned outages which usually entail the expense of outside contractors, including the reactor supplier. These outages can run into tens of millions of dollars, not including replacement power. And while quite infrequent, these outages can last up to three years in the worst case, although most are far shorter in duration. With the plant owners and lenders at risk for these expenses, it becomes almost mandatory to avoid such occurrences if the nuclear plant is to avoid significant and unrecoverable losses. The most recent example was the vessel head cracking problem where the nuclear plant was forced to shutdown for over two years to remedy the problem and demonstrate to the NRC that the company could operate the plant safely. This would be a devastating occurrence for a nuclear plant where the owners and lenders are at risk for the funds.

The best line of defense is an unrelenting culture of safety-a very visible feature of the best run nuclear plants.. Interestingly enough, deregulation provides added incentive for developing and maintaining a safety culture since any costs due to lapses in safety must be borne by the investors and not by the ratepayers. The Figure 8A-1 in the Appendix illustrates this point; safety and low cost go hand in hand. The best nuclear performers, such as Exelon and Entergy, have extensive preventive maintenance programs to anticipate and act well in advance of a forced shutdown. These programs, along with a LTSA from the reactor supplier are the reason that an outsourced plant management strategy is proposed.

We have assumed that top quartile performance in the case of production costs. The non-fuel O&M used in the risk model is at $70/kWe-typical of the best run U.S. nuclear plants.

COL Licensing Risk

The COL licensing risk, as we have defined it, is comprised of two concerns:
1) The NRC staff won't keep to its COL schedule despite the best efforts of the applicant, and;
2) An intervener(s) with standing will raise numerous admissible contentions during the COL review process and delay the project considerably.

These risks and what can be done to manage them were discussed fully in the report for Task 4. In summary, we wrote that to reduce this particular risk the project management team should:

1. Make full use of industry programs,
2. Form a consortium that commits to construction and not just the acquisition of an early site permit or a COL;
3. Before submitting the COLA, select a plant design for which the supplier has made a contractual commitment to the price and schedule.
4. Commit to an early and extensive public outreach program.

17 The industry has spent over $1 billion on security issues since the three years since September 11th.

Other Uncertainties: Carbon and Emissions Legislation

The possibility of limits or penalties on the emission of carbon is an uncertainty which has not been addressed in this Study to any depth. Obviously this would benefit the nuclear plant substantially, even if no credits were given to nuclear power for its role in reducing greenhouse gases. Market prices would be expected to increase sharply in the case of stringent carbon and emissions caps were legislated.

The pricing model used in Task 6 to study the economics of the plant contains provisions for the possible imposition of legislation to limit emissions from fossil fuel plants, and the resulting increase in market clearing prices. However, as mentioned above, it has been the objective of this effort to not rely on increased pricing from environmental legislation as the basis for a nuclear plant. It is only one possible future (see Task 6) and, while it would appear that such legislation will ultimately be passed, it could be some time before it happens. As is well known, the issue of climate change and the role that carbon plays is both scientifically and politically controversial. While nuclear power will probably play a role in a carbon diminished energy economy, this is not universally accepted as well. With this level of uncertainty, it seems wise not to rely to any great extent on this coming to pass in order to justify building a nuclear plant. It is much easier to justify a nuclear plant on the basis of a new regulation and cost regime

Other Uncertainties: Spent Fuel Waste Disposal

The outlook for final approval and eventual opening of the national spent fuel repository at Yucca Mountain is clouded. While it would seem that there is a low probability that the planned repository at Yucca Mountain will not accept fuel, it is not certain and for this reason spent fuel disposal is viewed with caution by potential investors, and eight States have bans on nuclear construction barring evidence that a spent fuel repository exists.[18] No such ban is currently proposed for Texas.

Since the DOE is responsible for removing spent fuel from reactor sites, and the cost of the program is paid for from the revenues of nuclear generators, the caution exhibited by investors appears unfounded.[19] This caution could only be caused by the belief that ultimately a failure at Yucca Mountain will result in a cost being borne by the plant owners, in spite of the government's obligation to remove the fuel from the site or pay for on-site long term storage.

In order to measure the impact of such a possibility on the plant's ability to be financed a model was developed. This model makes the assumption that rational owners of a nuclear plant would not chance the possibility that a large spent fuel storage cost would occur at the end of the reactor's life if no permanent spent fuel solution has been developed at the time the plant began commercial operation. Such an unfunded cost at the end of a nuclear plant's life would present intractable options to the owners of the plant. Costs in the hundreds of millions of dollars without provision for

18 The ban in Illinois might be tested by Exelon as it is currently involved in one of the consortia to obtain an early site permit for a new nuclear plant to be built in Illinois (the current Clinton site)

19 It is assumed that the DOE will extend the provision to remove and take title to spent nuclear fuel to new nuclear plants.

recovery are more charity than business. So, rational owners would establish a fund for such a contingency during the plant's lifetime in recognition of the possibility that it might be needed. This is already required for decommissioning the plant and this would simply be an added amount. Naturally, in a competitive market this would detract from the economic attractiveness of the plant, which is what potential investors may be concerned about. Adding to the problem is the fact that it is not known with any degree of accuracy how much should be accumulated in the fund. The reference model case does not include this potentiality.

Using this assumption and further assuming that an on-site spent fuel storage facility will cost at least $400 million, an assessment of the impact on the attractiveness of the plant was made.[20] The results indicate that anywhere from a 17 to 122 basis point premium might be applied by investors to the presence of this risk with an average of around 60 basis points depending on the presence of other risks, such as capital cost and price risk. This tends to reinforce the impression that although investors talk about spent fuel disposal as a "showstopper"; that, in fact, small to moderate sized risk premiums might be expected. This is not to diminish the seriousness of this issue; but rather to illuminate the fact that this risk is accommodated by investors in the traditional way; by pricing risk accurately.

Opportunity Management

While this Task is focused on risk management, it should be pointed out that there are several sources of uncertainty that could result in positive NPV increases. For example, an uncertainty with positive overtones is the possibility that electricity pricing will reflect the cost of strict environmental regulation including carbon and other emissions caps. In the model no credit is given to nuclear power for its ability to offset these fossil emissions. The view has always been that the nuclear plant must be able to compete without the need for legislated price increases. Should such a pricing regime emerge, over $300 million of plant value could ultimately accrue to the owners of nuclear plants such as the one being proposed in this Study.

Another uncertainty that might prove more optimistic is the issue of the decommissioning fund. Right now the model assumes that $135 million is established as the initial funding for decommissioning in 2015. This fund will build to the necessary decommissioning reserves in 2056 at a conservative rate of interest (2% real). There is no provision for recovering this cost from revenues. However, depending on the ownership structure, it may very well be possible to recover this from ratepayers of municipal utilities, or any other owner having ratemaking authority. Were this to happen, then the initial funding may be lowered. The NRC has not formulated a decommissioning fund policy for nuclear plants operated by owners without ratemaking authority.

20 See Interim storage of Spent Nuclear Fuel, A Joint Report From the Harvard University Project on Managing the Atom and the University of Tokyo Project on Sociotechnics of Nuclear Energy; Bunn, et al, June 2001,Harvard University and University of Tokyo (pages 13-15) (http://www.ksgharvard.edu/bcsia/atom. The reference estimates a 40 year dry cask storage cost of $250/kgHM. The TGCNF is expected to produce about 1624 MTU in its lifetime. The analysis assumes that no fuel is shipped to storage during the life of the plant.

ACRONYMS

ACRONYMS AND DEFINITIONS

ACRONYM	DEFINITION
AACEI	American Association of COST Engineers International
ACRS	Advisory Committee on Reactor Safeguards
AEA	Atomic Energy Act
ANP	Advanced Nuclear Plant
ASLB	Atomic Safety and Licensing Board
BV	Black & Veatch
BWRD	Brackish Water Reverse Osmosis
CFR	Code of Federal Regulations
CHP	Continued Heat and Power
COL	Combined Construction and Operating License
COLA	Combined Construction and Operating License Application
CPCN	Certificate Public Utilities Commission
CTQ	"Critical - to -Quality" of the product purchased by the end user such as electricity, steam, and process (a term associated with the Six Sigma methodology for defect elimination.)
DC	Design Certification
DCD	Design Control Document
DMAIC	Define, Measure, Analyze, Improve and Control
DMEDI	Define, Measure, Explore, Develop, and Implement
DOE	Department of Energy
DOJ	Department of Justice
DSHS	(Texas) Department of State Health Services
EA	Exclusion Area
EA	Environmental Assessment
EEDB	Energy Economic Data Base
EDC	Engineering Procurement and Construction
EIS	Environmental Impact Statement
EP	EnergyPath

ACRONYM	DEFINITION
EPC	Engineering Procurement and Construction
EPRI	Electric Power Research Institute
EPZ	Emergency Planning Zones
ER	Environmental Report
ERCOT	Electric Reliability Council of Texas
ESP	Early Site Permit
FDA	Final Design Approval
FEMA	Federal Emergency Management Agency
FEIS	Final Environment Impact Statement
FMEA	Failure Modes and Effects Analyses
FOAK	First of a Kind
FOAKE	First of a Kind Engineering Program
FSAR	Full Safety Analysis Report
GEN IV	Generation Four
GW	Gigawatts
INEEL	Idaho National Engineering and Environmental Laboratory
IOU	Industrial Owned Utilities
ITAAC	Inspections, Tests, and Acceptance Criteria
kv	kilovolt
kwh, kWh	kilowatt hour
LPZ	Low Population Zone
MBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt hour
NEPA	National Environmental Policy Act
NRC	Nuclear Regulatory Commission
OBE	Operating Basis Earthquake
O&M	Operation and Maintenance
PPA	Power Purchase Agreement

ACRONYM	DEFINITION
PPE	Plant Parameter Envelope
PRA	Probablistic Risk Assessment
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
REP	Request for Proposal
REP	Retail Energy Provider
RIOC	Return on Invested Capital
RMR	Reliability Must Run
SAMA	Severe Accident Mitigation Alternative
SER	Safety Evaluation Report
SERC	Southeast Electric Reliability Council
SWRO	Sea Water Reverse Osmosis
SMR	Steam Methane Reforming
SSE	Safety Shutdown Earthquake
STP	South Texas Project
SWMED	Sea Water Multiple Effect Distillation
TDSP	Transmission and Distribution Service Providers
TGCN	Texas Gulf Coast Nuclear
TEDE	Total Effective Dose Equivalent
TIACT	Texas Institute for Advancement of Chemical Technology
TSD	Technical Support Document
TSP	Transmission Service Provider
TVO	Teollisuuen Vioma Oy Finish Utility
USEC	U.S. Enrichment Corporation
W	Weight assigned to each CTQ